Chapter Four

Carbon and Other Emissions in the End-Use Sectors

Abstract

The growth in natural gas resources comes at a time when three very important issues have come to the forefront of public concern: energy security, environmental protection, and economic growth. This section of the report provides analysis surrounding the contribution natural gas can make towards a "lower carbon energy future" by reducing emissions of greenhouse gases* (GHGs) as well as criteria pollutants and mercury. In addition, policy and regulatory levers and technology options that could help achieve those reductions are identified and the comparative life-cycle emissions of natural gas and coal in power generation are also analyzed.

The chapter is sectioned into six areas, beginning with a summary and followed by the establishment of emissions baselines used throughout this report. An analysis of the life cycle of emissions of natural gas- and coal-fired generation appears third, which is followed by a discussion of natural gas end-use technologies and the potential for these to reduce emissions. The fifth segment covers the impact of non-GHG rules on the power sector, and the chapter ends with a series of policy recommendations.

* The major greenhouse gas emissions reviewed in this report are carbon dioxide, nitrous oxide, and methane.

SUMMARY

Given the abundance of natural gas supplies in the United States, natural gas can play a significant role in the energy consumption patterns of the country and the transition to a "lower carbon energy future." Accelerated deployment of end-use natural gas technologies offers an important opportunity for reducing future GHG and criteria pollutant emissions. This chapter reviews the potential for reductions in U.S. emissions of air pollutants and greenhouse gases through the increased use of natural gas in end-use sectors and associated policies to support those goals. In addition, emissions reductions in the power sector as a result of upcoming Environmental Protection Agency (EPA) actions on non-GHG environmental rules were analyzed along with the life-cycle emissions of natural gas and coal in power generation.

The analysis determined that expanded supplies of natural gas will significantly impact the economics of fuel choices and that natural gas could play a pivotal role in reducing emissions from various end-use segments including the electric power sector. Increased natural gas supplies, along with policies to place a "price on carbon"[1] to reduce GHG emissions, may yield a market-driven substitution of natural gas for other fuels (mainly coal). This makes natural gas an attractive option in a suite of options for meeting emissions targets in the near- to midterm

1 See http://www.ipcc.ch/pdf/assessment-report/ar4/wg3/ar4-wg3-annex1.pdf. Generally, the term "price on carbon" refers to the recognition of the negative externalities of GHG emissions and the associated economic value of reducing or avoiding one metric ton of GHG in carbon dioxide equivalent (1 $MtCO_2e$). In this report, there is no differentiation between an explicit carbon price (e.g., under a cap and trade or carbon tax policy) and an implied carbon cost (e.g., specific regulatory limitations on the amounts of emissions).

(i.e., to 2030) as well as in the longer term (e.g., a 50% reduction from a 2005 baseline by 2050). In the next few years, low natural gas prices – combined with upcoming environmental regulations affecting relatively old and inefficient coal-fired power plants without adequate emission controls – will likely result in the retirement of many coal plants. External reports estimate the retirement of roughly 18% of total U.S. coal-fired generation capacity (or about 58 gigawatts [GW]) by 2020. In addition, several technologies can be applied to various sectors of the economy that could reduce economy-wide emissions between 120 and 860 million metric tons of carbon dioxide equivalent per year (million $MtCO_2e$/year) by 2030. A steeper long-term emissions reduction target (e.g., 80% below 2005 by 2050) will likely also require more aggressive emission control technologies like carbon capture and sequestration (CCS) for natural gas and coal to be utilized.

To optimize the benefits of natural gas in promoting economic, energy, and environmental security, policymakers must work simultaneously and strategically on multiple policy fronts. These include providing regulatory certainty by finalizing the EPA proposed rules for coal-fired power plants and also addressing specific implementation hurdles, such as grid reliability. While a natural gas-fired power plant has about 50–60% lower GHG emissions on a life-cycle basis than a typical coal-fired power plant, policies should be implemented to encourage natural gas system operators to minimize their GHG emissions by implementing appropriate GHG reduction technologies across the life cycle. However, even with updated natural gas resource estimates, coal-fired generation retirements, and the institution of favorable policies, the energy mix in a carbon-constrained economy will be comprised of a diverse mix of low-carbon resources.

EMISSIONS BASELINE AND PROJECTIONS

In order to compare the projected range of emissions of air pollutants and GHGs in the U.S. end-use sectors, an analysis was performed to determine the baseline level of emissions. The National Petroleum Council (NPC) study selected 2005 as the baseline year since legislation introduced in the 111th Congress employed 2005 as the baseline year,[2] and also to ensure consistency with the parallel Future Transportation Fuels study. The 2005 baseline year thus serves as the reference point with which emissions projections can be compared.

The Energy Information Administration's (EIA) Annual Energy Outlook 2010 (AEO2010) Reference Case and Low and High Macroeconomic Cases were used to define the baseline and projected range of GHG emissions.[3] For non-CO_2 GHG emissions, data were used from the EPA for the baseline and projected emissions.[4] Additionally, the AEO2010 provides emissions projections for power sector sulfur dioxide (SO_2), nitrogen oxides (NOx), and mercury (Hg). The study used EPA data for 2005 baseline emissions of SO_2, NOx, and Hg.[5,6] The emissions projections in the AEO2011 Reference Case were also examined for CO_2.[7]

In general, the AEO2010 Reference Case assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection. Currently, there are many pieces of legislation and regulation that would affect GHG emissions as well as proposed legislation that may be enacted in the near term. In addition, some laws include sunset provisions that may or may not be extended. However, it is difficult to discern the exact form that the final provisions of pending legislation or regulations will take, and to determine if sunset provisions will be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, there is uncertainty as to how those regulations will ultimately be implemented. Therefore, the AEO2010 provides a current policy and technology baseline for decision makers to use in assessing the implications of alternative scenarios that vary assumptions about

2 S. 1733, Clean Energy Jobs and American Power Act; H.R. 2454, American Clean Energy and Security Act of 2009.

3 Annual Energy Outlook 2010 with Projections to 2035, DOE/EIA-0383(2010), April 2010. AEO2010 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91) 2 S. 1733, Clean Energy.

4 U.S. Environmental Protection Agency, *2011 U.S. Greenhouse Gas Inventory Report*, April 15, 2011.

5 SO_2 and NOx emissions data can be found at: http://www.epa.gov/air/emissions/index.htm.

6 Mercury emissions data can be found at: http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewReference&ch=46&lShowInd=0&subtop=341&lv=list.listByChapter&r=216615.

7 The AEO2011 was published in April 2011, after the vast majority of this report was finalized. Hence, the study team used the AEO2010 data for the majority of the analysis presented in the study.

Framing Questions

The End-Use Emissions and Carbon Regulation Subgroup of the Coordinating Subcommittee was asked to address several specific framing questions:

1. What are the current and projected ranges for emissions of air pollutants and greenhouse gases (GHGs) from U.S. natural gas end-use sectors?
2. What is the impact of carbon constraints on end-use natural gas consumption?
3. What are the life-cycle emissions of natural gas and coal, with special focus on the power generation sector?
4. What are the potential technologies for reducing U.S. natural gas end-use sector GHG emissions and the associated costs to deploy them at scale?
5. What is the impact of upcoming non-GHG rules on the power sector in terms of coal plant retirements, potential increased use of natural gas, and reduction of GHGs and other emissions?
6. What are the various policy designs that optimize GHG reductions with accelerated deployment of natural gas end-use technologies?

economics, regulations, or technology.[8] The AEO2010 does include evolutionary technological progress based on ongoing investment by manufacturers and others, but it does not assume revolutionary technological breakthroughs.

Summary of Findings

- Assuming no changes in current policy, U.S. GHG emissions are expected to be 9% higher than 2005 baseline emissions by 2035, or 7,900 million $MtCO_2e$/year in the Reference Case scenario.
- The recent decrease in emissions is mostly the result of the recent economic recession, which is expected to have a lasting impact on GHG emissions. In the Reference Case, GHG emissions remain below the 2005 baseline level until 2017. In the Low Economic Growth case, U.S. GHG emissions are projected to remain below 2005 levels until 2026, while in the High Economic Growth case, emissions return to 2005 levels by 2014.
- In the absence of a national policy to constrain GHG emissions, breakthroughs in technology, or major changes in consumer behavior, economic growth has the largest impact on GHG emissions. In the High Economic Growth case, emissions rise to 8,400 million $MtCO_2e$/year by 2035. In the Low Economic Growth case, emissions rise to 7,300 million $MtCO_2e$/year by 2035.
- Increased natural gas supplies, along with policies to reduce GHG emissions, will yield a market-driven substitution of natural gas for other fuels (mainly coal). This makes natural gas an attractive option in the near- to midterm (i.e., to 2030) and in the longer term with emissions targets (e.g., 50% reduction from a 2005 baseline by 2050). A steeper long-term emissions target (e.g., 80% by 2050) will likely also require more aggressive emission control technologies, like CCS, for both coal and natural gas power plants.

8 See the Carbon Subgroup's Topic Paper #4-1, "Baseline and Projections of Emissions from End-Use Sectors," for more detailed assumptions.

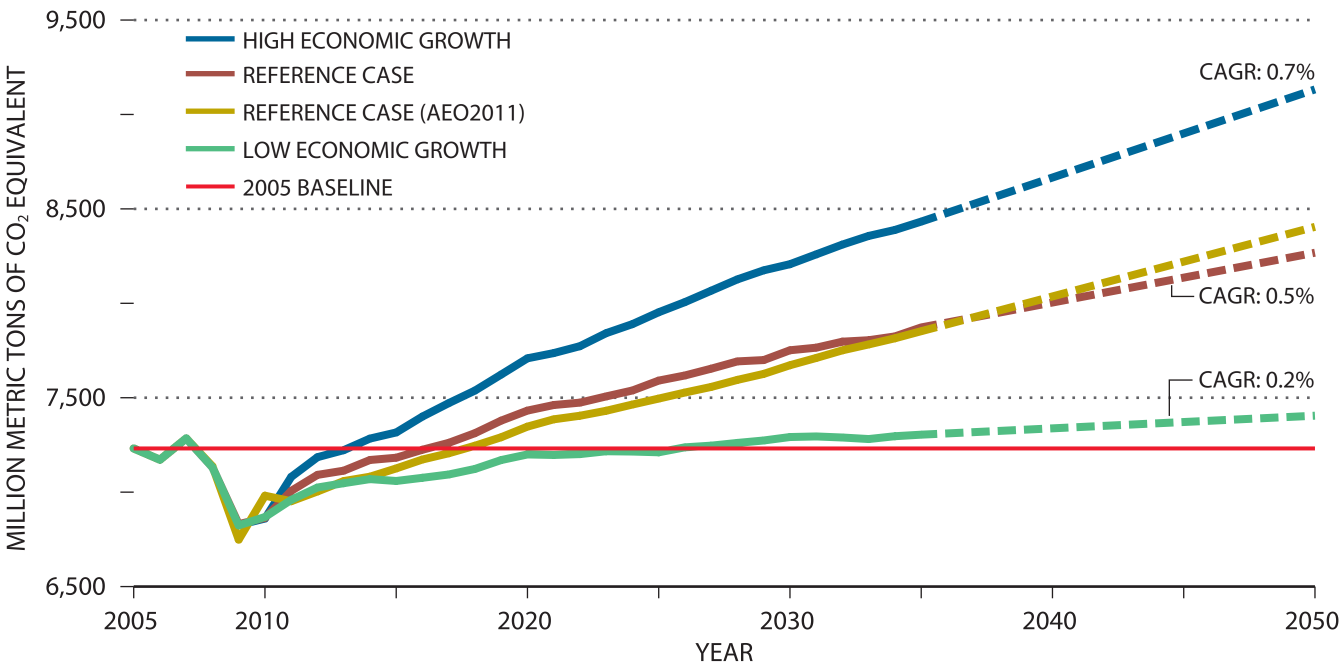
Greenhouse Gas Emissions: Unconstrained Cases

Figure 4-1 displays GHG emissions projections for four cases: three from the AEO2010 (Reference, High Economic Growth, and Low Economic Growth Cases), and the AEO2011 Early Release Reference Case.[9] None of the four cases include any economy-wide constraints in the form of policy or regulation on GHG emissions.[10] In the Reference Case, GHG

9 The AEO2011 has not updated emissions for "other GHGs"; thus, non-energy-related CO2 emissions have been estimated by the NPC. For more information on the AEO2011 emissions, please see http://www.eia.gov/forecasts/aeo/.

10 The AEO2010 includes State RPS programs and CAFE standards per EISA2007, Public Law 110-140. Please see http://www.eia.gov/oiaf/archive/aeo10/leg_reg.html. The AEO2010 includes a 3-percentage point increase in the cost of capital for GHG intensive technologies, including CTL plants and coal-fired power plants without CCS, to reflect the behavior of utilities, other energy companies, and regulators concerning uncertainty created by the possible enactment of GHG legislation, which could mandate that owners purchase allowances, invest in CCS, or invest in other projects to offset their emissions in the future. For more information, please see http://www.eia.gov/oiaf/archive/aeo10/electricity_generation.html.

Figure 4-1. Greenhouse Gas Emissions – 2005 Baseline and Projections



Notes: Dashed continuations represent linear extrapolations of AEO projections based on 2026–2035 values.
CAGR = Compound Annual Growth Rate.
Source: EIA AEO2010 and AEO2011 – Preliminary Results.

emissions rise to about 7,200 million $MtCO_2e$/year by 2015. Energy-related CO_2 makes up 80% of GHG emissions with the remainder coming from methane (10%), non-energy CO_2 (2%), nitrous oxide (5%), and fluorinated gases (4%).[11] By 2035, GHG emissions rise to about 7,900 million $MtCO_2e$/year, with minimal changes in the percentage share by gas. While the AEO2010 provides more than 30 alternative cases, the Low and High Economic Growth Cases bounded the range of GHG emissions (Table 4-1).[12]

11 Fluorinated gases include hydrofluorocarbons (HFCs) and other ozone-depleting substances (ODS) substitutes, perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

12 See http://www.eia.gov/oiaf/aeo/tablebrowser/ for alternative cases.

The abundant supply of natural gas that is now projected gives the United States the opportunity to use natural gas to displace more carbon-intensive fuels, primarily coal used in the power sector and oil used for transportation.[13] Market prices have already begun to reflect a more robust North American gas supply. In turn, these lower natural gas prices have reduced wholesale electricity prices. Today, many large GHG emitters, especially those in the power sector, have already begun to alter their plans based on the long-term risk of GHG regulation. For example, many utilities today use carbon proxy prices in their resource planning to estimate the potential range of

13 The role of natural gas in the transportation sector is being addressed by the Future Transportation Fuels study.

Table 4-1. Emissions Data by Case (Million Metric Tons of Carbon Dioxide Equivalent)

Case	2005	2015	2035	2050*
High	7,231	7,316	8,433	9,133
Reference	7,231	7,182	7,872	8,268
Low	7,231	7,059	7,304	7,405

* 2050 figures based on extrapolations.

impact of future GHG regulation.[14,15,16,17,18] As noted in Footnote 10, the AEO2010 reflects some carbon risk by increasing the capital cost of coal plants, but the incorporation of GHG risk into utility plans (as well as company decisions to proactively reduce GHG emissions on a case-by-case basis) may result in GHG emission reductions not reflected in the AEO Reference Case.

The greater use of natural gas, in lieu of coal, has resulted in a decrease in the carbon intensity[19] of the power sector by about 4%[20] in 2009 (relative to 2008). Over 120 GW of efficient, natural gas combined cycle (NGCC) capacity was added from 2000 to 2008. The increased use of these new and efficient natural gas units decreased the GHG emissions by about 83 million $MtCO_2e$,[21] or about 1% of total U.S. emissions in 2005. Similarly, the carbon intensity of the industrial sector has dropped by over 3% due to lower-carbon natural gas and renewable fuel consumption instead of coal and oil.

14 Ernest Orlando Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, *Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans,* March 2008. http://eetd.lbl.gov/ea/emp/reports/lbnl-44e.pdf.

15 Direct Testimony of Kurtis J. Haeger, Public Service Company of Colorado, before the Public Utilities Commission of the State of Colorado, May 13, 2011. http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/CO-11A-XXXE_2012_RES_Haeger_DirectTestimony.pdf.

16 Tennessee Valley Authority, *Integrated Resource Plan, TVA's Environmental & Energy Future,* March 2011, page 97. http://www.tva.gov/environment/reports/irp/pdf/Final_IRP_complete.pdf.

17 Oklahoma Gas & Electric Co., *Integrated Resource Plan,* May 2011, page 62. http://occeweb.com/pu/OGE%202011%20IRP.pdf.

18 American Electric Power, *Integrated Resource Plan, 2010-2019,* July 2009, page 28. http://occeweb.com/pu/PSO%202011%20IRP.pdf.

19 Carbon intensity of energy is defined as carbon dioxide emissions per unit of energy consumed (CO_2/Btu).

20 Energy Information Administration, "U.S. Carbon Dioxide Emissions in 2009: A Retrospective Review," May 2010. http://www.eia.doe.gov/oiaf/environment/emissions/carbon/.

21 Energy Information Administration, *Monthly Energy Review,* April 2011. Theoretical reductions computed relative to 2000 and computed as reductions in emissions had the emissions intensity of the gas generation fleet not changed. Similarly, in 2010, reductions were estimated by the EIA at 88 million $MtCO_2e$.

Greenhouse Gas Emissions: Constrained Scenarios

The study team explored the impacts of carbon constraints on natural gas demand, specifically in the power sector. In this study, a "carbon constraint" is an implied or explicit limit on GHG emissions that may result in cost impacts for the end-user that did not exist previously and that reflects in some fashion the relative carbon intensity of fuel and technology choices. In practice, carbon constraints may take the form of a work practice or performance standard or a "cap" or "tax" on emissions. Rather than analyze and model the results of specific GHG reductions or targets, the role of natural gas in reducing GHGs was reviewed as reported in the various studies used to complete the "study of studies." Long-term carbon constraints of a 50% reduction from a 2005 baseline by 2050 and steeper long-term emissions targets (e.g., 80% by 2050 or later) were reviewed as part of this analysis.

There are very few studies in the public domain that incorporate the potential effects of increased natural gas resources,[22] as in the cases presented in the AEO2011, suggesting that many currently available studies may underestimate the potential for natural gas use. To study the relationship of carbon constraints and the larger natural gas supplies, the NPC study team reviewed EMF (Energy Modeling Forum) 22: Climate Change Control Scenarios,[23] "The Future of U.S. Natural Gas Production, Use, and Trade,"[24] "Natural Gas: A Bridge to a Low-Carbon Future?",[25]

22 The estimate for technically recoverable unproved shale gas in the AEO2011 Reference Case is 827 Tcf. Alternative cases in AEO2011 examine the potential impacts of variation in overall domestic natural gas production from 22.4 to 30.1 Tcf in 2035, compared with 26.3 Tcf in the Reference Case.

23 See http://emf.stanford.edu/research/emf22/ for more information. EMF (Energy Modeling Forum) 22 is a compilation of results from six modeling teams that focused on 50 and 80% GHG emissions reductions from 1990 levels. As part of this study, results were averaged from the following model outputs (ADAGE, MRN-NEEM, EPPA, MERGE-Optimistic, and MiniCAM-EERE) to represent the outcomes from EMF.

24 Massachusetts Institute of Technology (MIT), "The Future of U.S. Natural Gas Production, Use, and Trade," Interim Report, 2010. http://globalchange.mit.edu/pubs/abstract.php?publication_id=2066.

25 Stephen P. A. Brown, Alan J. Krupnick, and Margaret A. Walls, "Natural Gas: A Bridge to a Low-Carbon Future?", Resources for the Future Issue Brief 9-11, December 2009.

EIA's AEO2011 GHG price economy wide case, and private modeling results provided by Wood Mackenzie. The conclusions are:

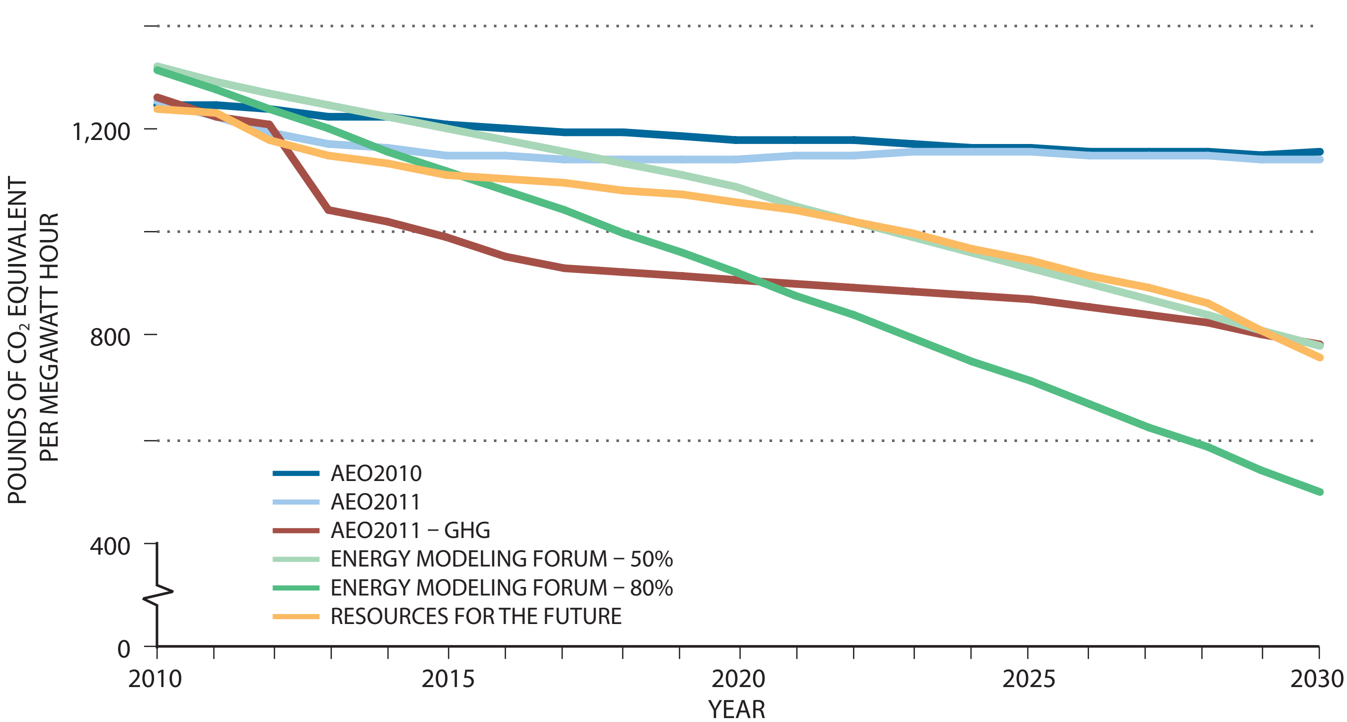
- Relative to a reference case without GHG emission limits,[26] past studies have indicated carbon constraints result in lower energy consumption – on an economy-wide basis – and power sector emission intensity declines over time (Figure 4-2). As noted above, past studies have shown that carbon constraints typically resulted in reduced total energy demand relative to the Reference Case for the comparative year, including economy-wide demand for natural gas. However, under certain cases, even with carbon constraints, an increased market share of natural gas in the power sector was observed (Figure 4-3). Additionally, in cases with higher natural gas supplies, end-use natural gas consumption, on an economy-wide basis, may increase in absolute terms (Figure 4-4, EIA, and Wood Mackenzie) relative to a reference case without carbon constraints. However, due to the limited detailed analyses in the public domain, definitive conclusions were unable to be drawn about whether higher levels of natural gas supplies (such as those used in AEO2011) and carbon constraints would indeed result in higher gas consumption in the economy.

- Even with updated resource natural gas resource estimates, the electricity mix in a carbon-constrained economy will be comprised of a diverse mix of low-carbon resources. Power sector natural gas demand will depend not only on natural gas supply and price but also its competition on with other low-emitting electricity technologies; policies designed to increase renewable technologies such as Renewable Energy Standards would alter that competition. Different assumptions of technology competition yield vastly different future power generation mixes (Figures 4-5 and 4-6).

- The increased natural gas supplies and associated lower gas prices may significantly expand the role of natural gas as one among the suite of viable, economical options to meet GHG emissions

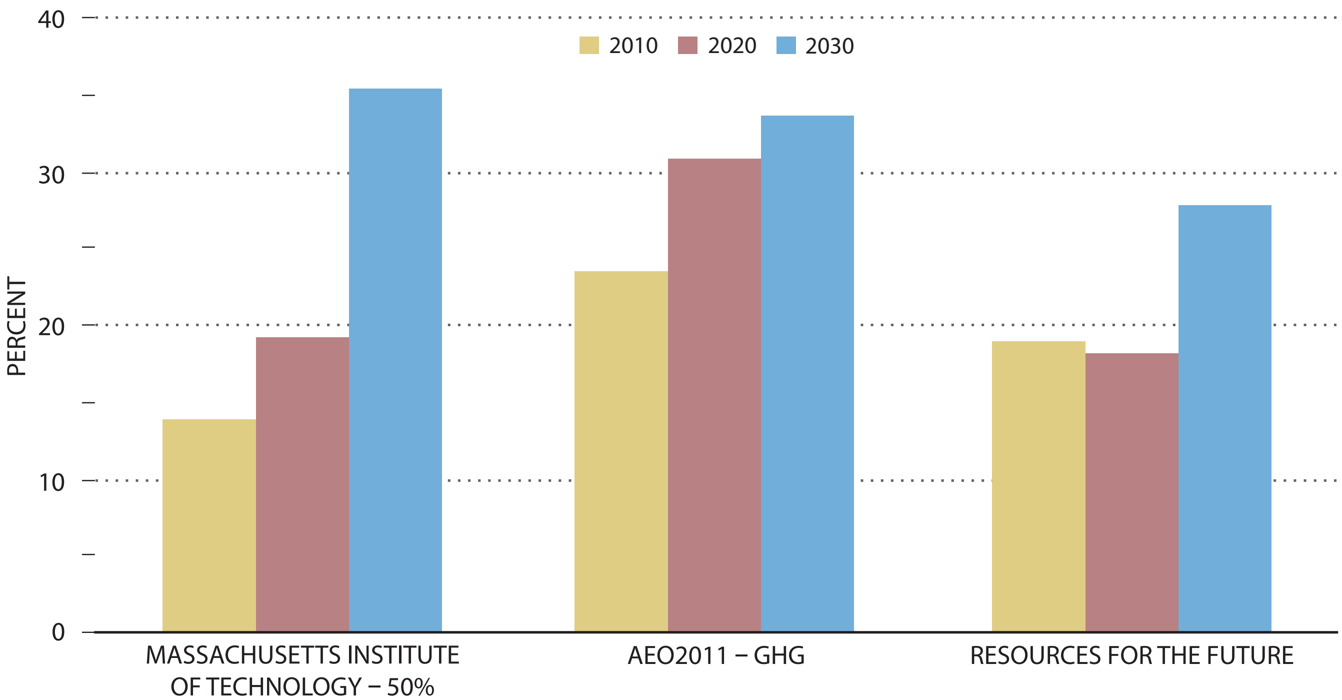
26 The term "Reference Case" in this report implies the projection of emissions or gas/electric/energy demand that would have occurred under current regulatory or business-as-usual conditions for a particular year.

Figure 4-2. Power Sector Emissions Intensity – Carbon-Constrained Scenarios



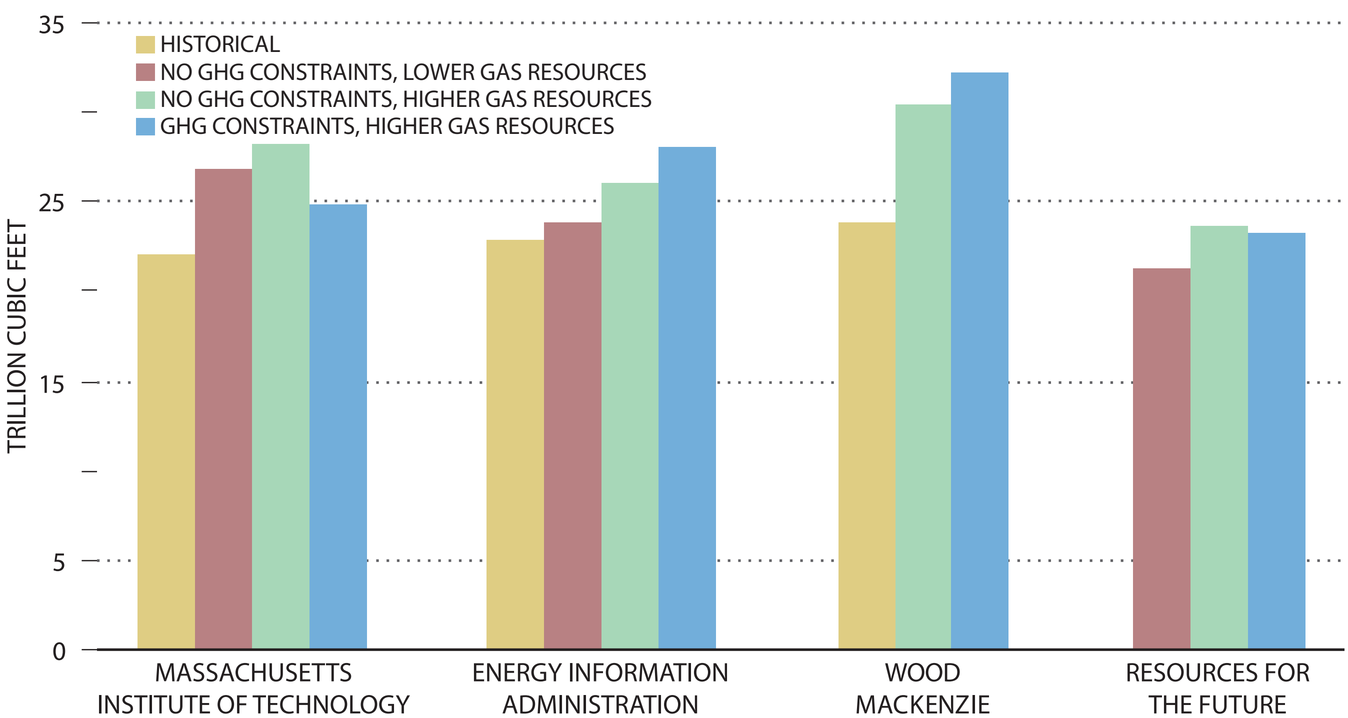
Note: GHG = greenhouse gas.

Figure 4-3. Natural Gas Generation in Carbon-Constrained Scenarios



Note: GHG = greenhouse gas.

Figure 4-4. Total Natural Gas Consumption in 2030



Note: GHG = greenhouse gas.

Figure 4-5. Massachusetts Institute of Technology: Energy Mix Under Carbon Policy, 50% Reduction by 2050

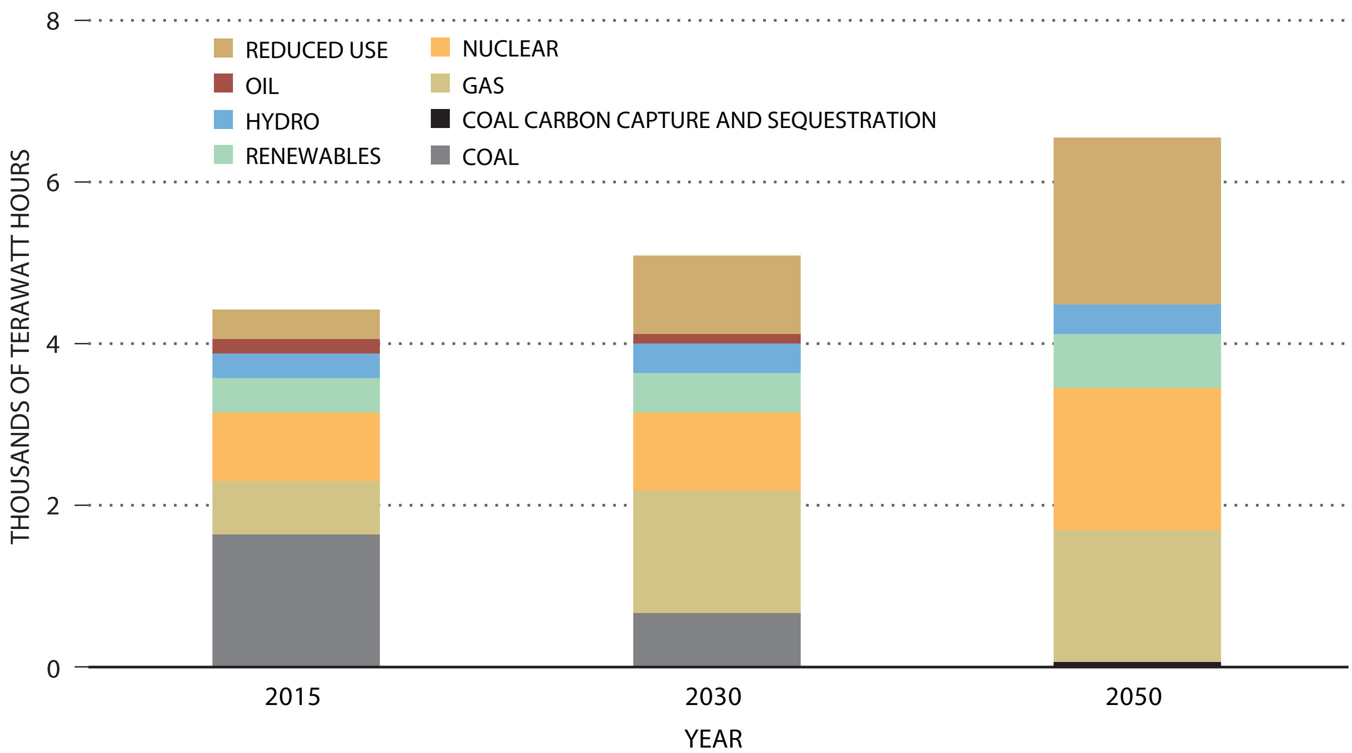
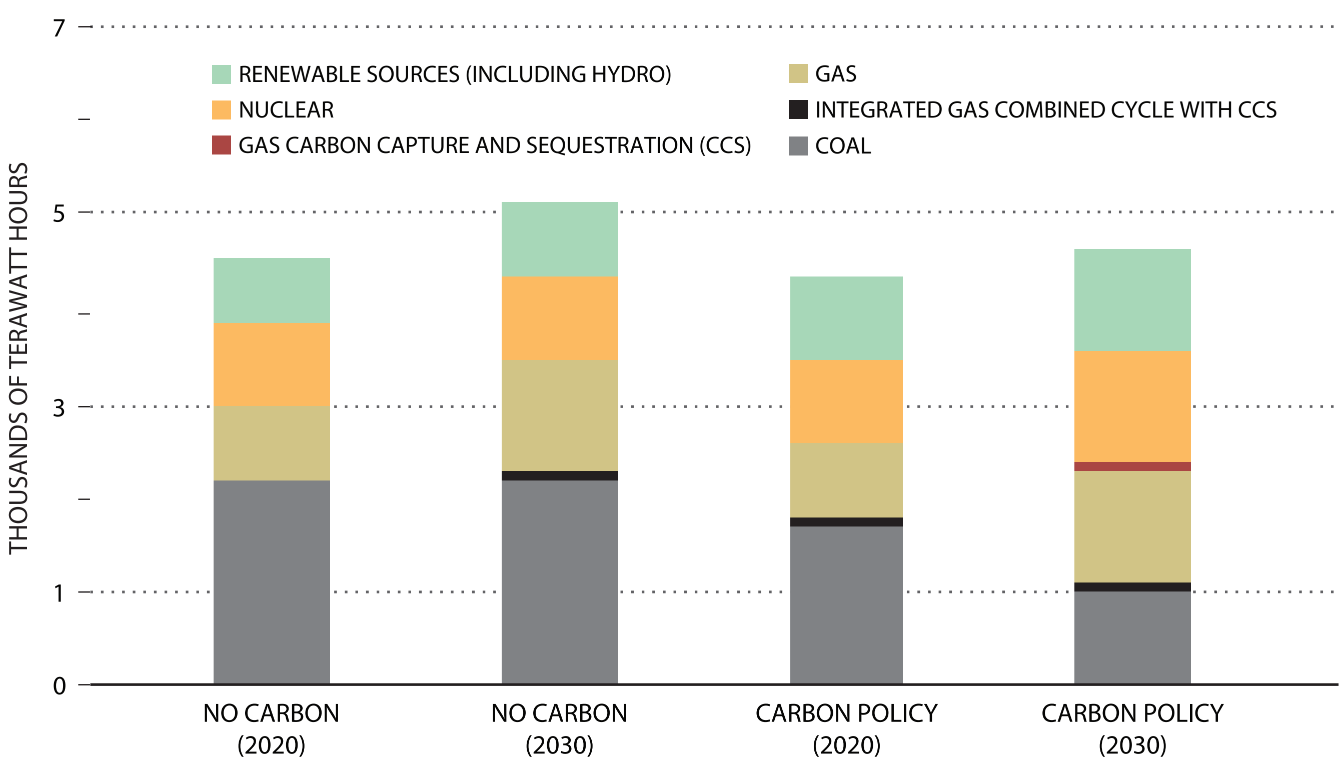


Figure 4-6. Resources for the Future: Energy Mix Under Carbon Policy, 42% Reduction by 2030



constraints of about 50% reduction from 2005 levels by 2050. However, under a more aggressive 80% GHG reduction target, natural gas, even with its relatively lower carbon intensity, cannot meet the carbon constraints alone without low- to zero-emitting technologies such as CCS. Hence, it is imperative that research, development, and demonstration (RD&D) efforts related to lower-carbon technologies, including CCS, continue if a steep, long-term target is established and substantial natural gas use is to be maintained over the longer term.

Sulfur Dioxide, Nitrogen Oxides, and Mercury

Table 4-2 displays 2005 baseline emissions for sulfur dioxide, nitrogen oxides, and mercury by sector. In the AEO2010 Reference Case (Figures 4-7 and 4-8), NOx and SO_2 emissions decline due to the impact of existing regulations, such as the Clean Air Interstate Rule,[27] and mercury emissions decline due to the impact of existing state regulations. Both NOx and SO_2 emissions are expected to decline further due to the impact of proposed Clean Air Act rules, which remain to be finalized by the EPA, that are not incorporated in the Reference Case.

27 The Reference Case includes the Clean Air Interstate Rule that was temporarily reinstated by the U.S. Court of Appeals for the District of Columbia Circuit in December 2008, which includes a cap-and-trade system for SO_2 and NOx emissions.

LIFE-CYCLE EMISSIONS OF NATURAL GAS AND COAL IN POWER GENERATION

As noted in the previous sections, natural gas can play a significant role in a lower carbon-constrained environment. Besides lowering GHGs, displacement of coal and fuel oil can also result in lower SO_2, NOx, and mercury emissions at the various end-use sectors. The demand for natural gas in the power sector is projected to increase in the next few decades. To fully analyze the emissions from the "well to the burner tip," a life-cycle analysis (LCA) was conducted comparing natural gas to coal.

The NPC analyzed the life-cycle emissions of natural gas in the power sector relative to coal employing similar methodologies as developed in the paper by Paulina Jaramillo et al.[28] The life-cycle analysis of emissions from natural gas and coal in power generation in the United States was then evaluated using the updated EPA GHG emissions inventory for 2009.[29] While the methane estimates presented in this EPA inventory have been questioned by both industry and

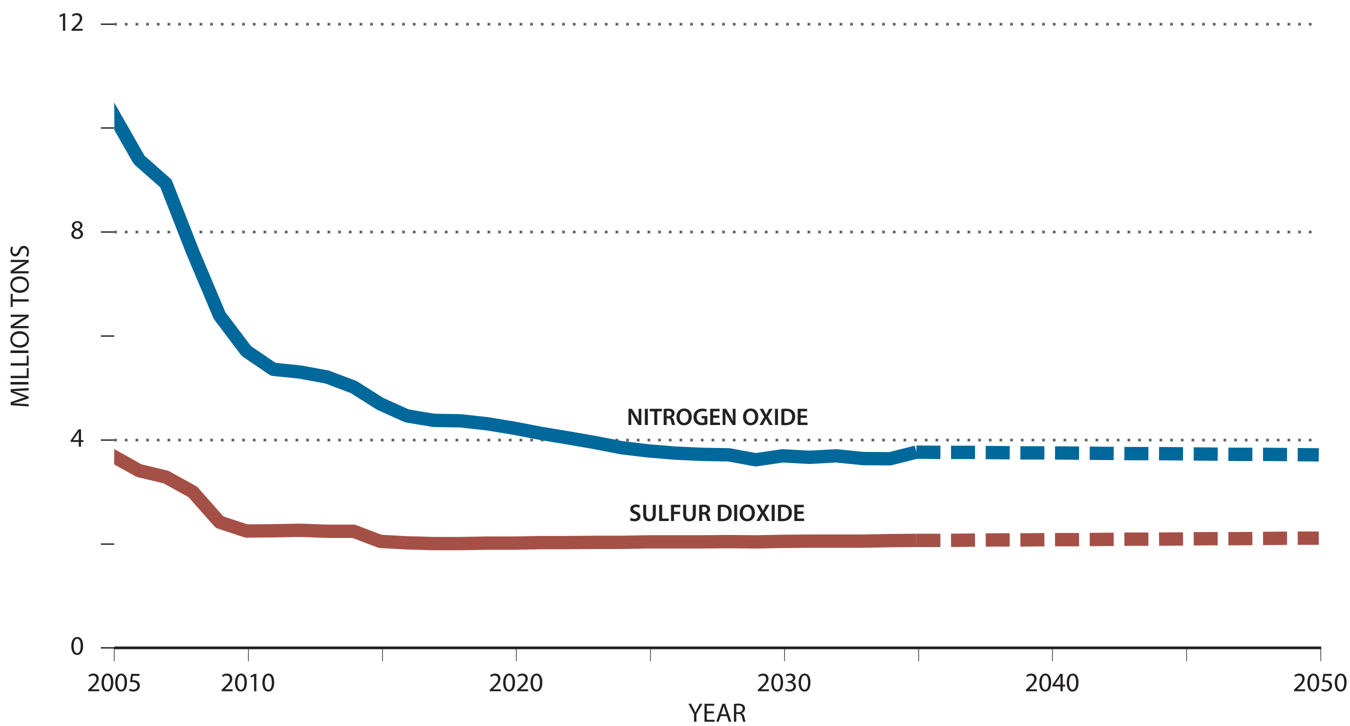
28 P. Jaramillo, W. M. Griffin, and H. S. Matthews, "Comparative Life Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation." *Environmental Science & Technology* (2007) 41(17): 6290–6296. Additional clarifications were provided by P. Jaramillo on February 5 and 7, 2011.

29 U.S. Environmental Protection Agency, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009," EPA 430-R-11-005, April 15, 2011, http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

Table 4-2. 2005 Baseline Emissions: Sulfur Dioxide, Nitrogen Oxides, and Mercury

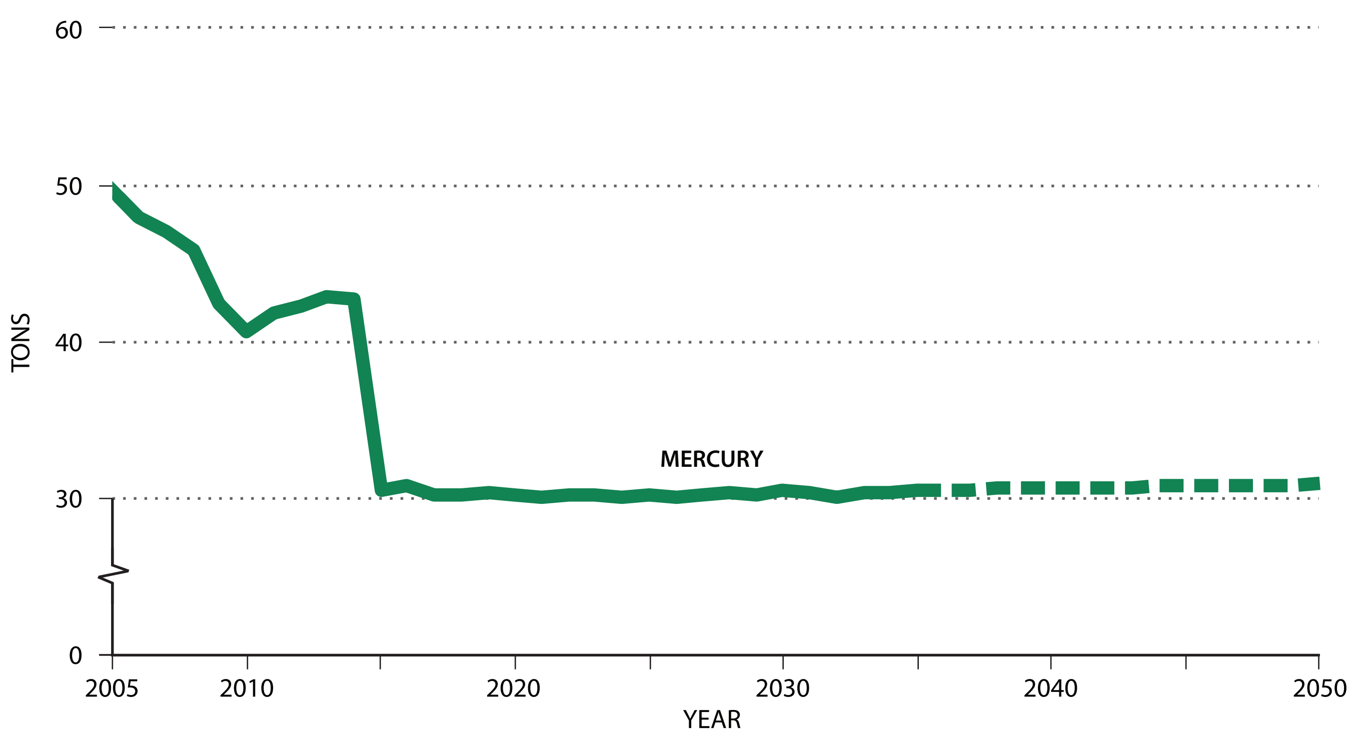
Pollutant	2005 Baseline Emissions	Unit (Short Tons)	
Sulfur Dioxide	Electric power	10	Million tons
	Transportation	1	Million tons
	Other	3	Million tons
	Total	14	Million tons
Nitrogen Oxides	Electric power	4	Million tons
	Transportation	11	Million tons
	Other	4	Million tons
	Total	18	Million tons
Mercury	Electric power	52	Tons
	Mobile sources	1	Tons
	Other	49	Tons
	Total	103	Tons

Figure 4-7. Emissions Projections – Power Sector, Nitrogen Oxide and Sulfur Dioxide



Note: Dashed continuations represent linear extrapolation of AEO projections based on 2026–2035 values.

Figure 4-8. Emissions Projections – Power Sector, Mercury



Note: Dashed continuation represents linear extrapolation of AEO projection based on 2026–2035 values.

Implications of Methane's Global Warming Potential

The life-cycle emission estimates presented in this chapter employed a 100-year global warming potential (GWP) for methane of 25 (unless otherwise noted).

Although most regulations and policy discussions consider the 100-year time horizon, this practice may not fully compare the impact of short-lived GHGs like methane versus longer lived GHGs like CO_2. Conversely, considering a shorter time horizon can give a more complete understanding of the near-term effects of shorter-lived species. The Intergovernmental Panel on Climate Change's current estimate of methane's 20-year GWP is 72. Using a 20-year GWP for methane would result in larger emissions estimates for the upstream portions of both coal's and natural gas' life cycles, although natural gas still produces lower overall equivalent CO_2 emissions than coal. For example, using a 20-year GWP of 72 for methane yields 1,281 lbs of carbon dioxide equivalent per megawatt hour (CO_2e/MWh) and 2,131 lbs of CO_2e/MWh for the heat rates of 7,000 British thermal units per kilowatt hour (Btu/kWh) and 9,000 Btu/kWh for natural gas and coal, respectively.

non-governmental stakeholders, they still represent the official inventory of the United States. Hence, the updated EPA inventory was employed in this LCA.

A global warming potential (GWP) of 25 for methane rather than 21 was employed in the LCA.[30] Also, emissions from energy consumption at mining operations were updated to 2007 using the latest coal mining fuel consumption statistics from the U.S. Census Bureau[31] and certain emissions not considered by Jaramillo et al. (non-combustion CO_2 emissions in natural gas systems[32]) were accounted in the NPC analysis.[33]

30 Based on a 100-year time horizon GWP value from the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4). For methane, the GWPs range from 72 (for 20-year time horizon) to 7.6 (500-year time horizon). See Table 2.14 (http://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-chapter2.pdf). The 100-year time horizon is commonly adopted for various regulations (e.g., AB32, EPA Reporting Rule) and legislative proposals (e.g., 111th Congress). The 100-year time horizon is also the estimate employed by the EPA and EIA in its emissions estimates and projections. GWP of 21 for methane is used by the EPA in its annual inventory reports (See Footnote 24), but it is from the IPCC's Second Assessment Report (SAR) issued in 1995.

31 U.S. Census Bureau, 2007 Economic Census. http://factfinder.census.gov/servlet/IBQTable?_bm=y&-geo_id=&-ds_name=EC0721I3&-_lang=en.

32 10.9 million MtCO_2e of non-combustion CO_2 were added to the natural gas LCA, Table 3-38, EPA.

33 The use of the Jaramillo et al. methodology or even adoption of the new revised EPA emissions in this report should not be viewed as an endorsement, but rather an attempt to place the analysis in the context of recent public discussions surrounding the impact of new EPA emissions data for the natural gas production sector and its impact on the overall natural gas life-cycle emissions.

The boundaries of the LCA included direct combustion and fugitive and vented emissions from the production/extraction, processing, and transportation of coal and natural gas. To ensure current representation of the current power production sector, technologies like CCS or integrated gasification combined cycle are not included. Emissions related to construction and decommissioning of the facilities are also excluded.

Life-Cycle Analysis of Natural Gas and Coal in Power Generation

Because of the new, revised EPA estimate of fugitive and methane emissions and the inclusion of non-combustion CO_2,[34] the NPC estimate of emissions for the natural gas value chain was 409 million MtCO_2e in 2009. Similarly, emissions from coal extraction, processing, and transportation were estimated at 136 million MtCO_2e/year employing methane emissions from the 2009 EPA inventory, the higher GWP of methane and emissions from energy consumption at mining operations (updated to 2007). The natural gas and coal emissions were normalized to a heat content basis (pounds of CO_2 equivalent per million British thermal units [lb CO_2e/MMBtu]), based on higher heating value, for comparison as fuels without consideration of additional efficiency differences in end-use technologies and natural gas emissions were found to be about 35% lower than coal (see Figure 4-9).

34 See Figure 4-9 for definitions.

Since the real focus going forward will be on new NGCC plants (about 52% efficient[35,36]) replacing older, inefficient coal plants (about 30% efficient) or the replacement of the older/inefficient capacity with new coal plants (about 38% efficient[37]), the net efficiency range for consideration by policymakers is much smaller, with combined cycle plants in the range of 49% efficient and coal plants in the 30–38% range.

Figure 4-10 represents the LCA emission rates computed at an NGCC plant of 7,000 British thermal units per kilowatt hour (Btu/kWh) (49% efficiency), 9,000 Btu/kWh (37% efficiency) for a new coal plant, and 11,377 Btu/kWh (30% efficiency) for an inefficient coal plant. For this nominal heat rate range, the natural gas plant consistently has life-cycle GHG emissions about half those of the coal plants. See Table 4-3 for comparison of life-cycle emission rates in the electric power sector.

EPA estimates an uncertainty of -19 to +30% for methane and non-combustion CO_2. Uncertainty ranges[38] from coal mining operations or fuel combustion of coal (-4 to +10%) or natural gas (-3 to +5%) and uncertainties associated with methane emissions from coal mine operations (-13 to +16%) are not illustrated in Figure 4-10.[39]

Other LCA Studies

Besides Jaramillo et al., there have been other recent studies about the LCA of natural gas and coal. Figure 4-11 provides a comparative analysis of the LCA as reported by Jaramillo et al. (adjusted for a GWP of 25), NPC, National Energy Technology Laboratory,[40] and the American Clean Skies Foundation.[41] In comparing the power generation emissions, the assumptions on generation efficiency and, in the case of the updated Jaramillo et al. analysis, the estimates in methane emissions are the main reason for the differences in the LCAs.

In a recent paper,[42] Robert W. Howarth et al. conclude that "[t]he large GHG footprint[43] of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming." To arrive at this conclusion, Howarth et al. compute that 3.6 to 7.9% of methane in natural gas, produced over the life cycle of a well, is emitted to the atmosphere. For conventional wells, Howarth et al. find the range to be between 1.7 and 6%. Using these data points and considering the 20-year horizon, Howarth et al. find that 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

35 The Jaramillo et al. paper uses an efficiency range of 30 to 37% for coal and from 28 to 58% for natural gas. Although Jaramillo et al. report a maximum higher heating value efficiency of 58% for a U.S. NGCC plant with F-class gas turbines, that value appears to be in error for an electricity-only plant. Efficiencies from the EIA's Annual Energy Outlook, Table 8.2– "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies," at http://www.eia.gov/oiaf/aeo/excel/aeo2010%20tab8%202.xls. The efficiency of an NGCC plant using EIA's estimate of an average heat rate of the first- and nth-of-a-kind (6,543 Btu/kWh), is about 52%. Coal plant efficiency is estimated at 38% based on average heat rate of 8,970 Btu/kWh for the first- and nth-of-a-kind "Scrubbed New Coal Plant."

36 Turbine manufacturers Siemens (SGT6-8000H: http://www.energy.siemens.com/hq/en/power-generation/gas-turbines/sgt6-8000h.htm) and GE (FlexEfficiency 50: http://www.ge-flexibility.com/products/flexefficiency_50_combined_cycle_power_plant/index.jsp) have announced gas turbines achieve fuel efficiencies greater than 60% on a lower heating value (LHV) basis.

37 Higher efficiencies, approaching 44–45% higher heating value, are possible for new coal plants employing ultra-supercritical units. S. Yeh and E.S. Rubin, "A Centurial History of Technological Change and Learning Curves for Pulverized Coal-Fired Utility Boilers," *Energy,* Vol. 32, p. 1996–2005 (2007). Technical Assessment Guide (TAG®)-Power Generation and Storage Technology Options, Report No.1017465, Electric Power Research Institute, Palo Alto, CA, December 2009, pages 3–19, 20.

38 See Table 3-16 in the Environmental Protection Agency's Greenhouse Gas inventory found at: http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Chapter-3-Energy.pdf.

39 See Table 3-31 in the Environmental Protection Agency's Greenhouse Gas inventory found at: http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Chapter-3-Energy.pdf.

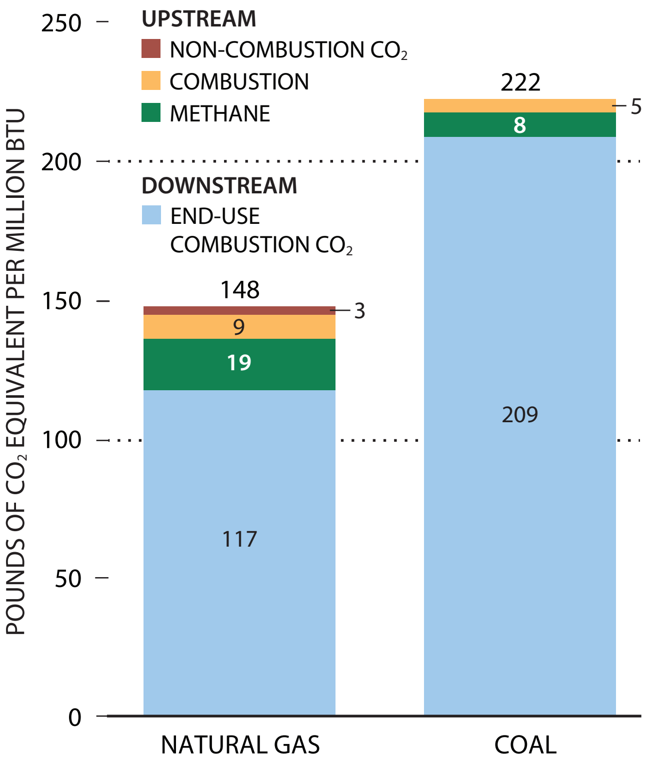
40 National Energy Technology Laboratory, "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States" (Timothy J. Skone, P. E., Cornell University Lecture Series, May 12, 2011).

41 American Clean Skies Foundation, "The Climate Impact of Natural Gas and Coal-Fired Electricity: A Review of Fuel Chain Emissions Based on Updated EPA National Inventory Data," April 19, 2011.

42 Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, "Methane and the Greenhouse-Gas Footprint of Natural Gas from Shale Formations," Climatic Change, 2011.

43 GHG footprint is defined by Howarth et al. "as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion."

Figure 4-9. Comparison of Fuel and Upstream Emissions



Notes: *Non-combustion CO_2* are emissions of CO_2 associated with flaring and removal of CO_2 from natural gas at acid gas removal units.

Combustion emissions are associated with combustion of natural gas in turbines, engines, boilers, and process heaters from the production, processing, transportation/storage, and distribution of natural gas.

Methane emissions are predominantly either fugitive (unintentional) or vented (intentional) releases of natural gas along the natural gas value chain.

End-use combustion CO_2 are emissions resulting from the combustion of the fuel at a combustion source (e.g., boiler, turbine, etc.) at the end-use sector (power, residential, commercial or industrial).

Figure 4-10. Life Cycle – Electricity Emissions Rate

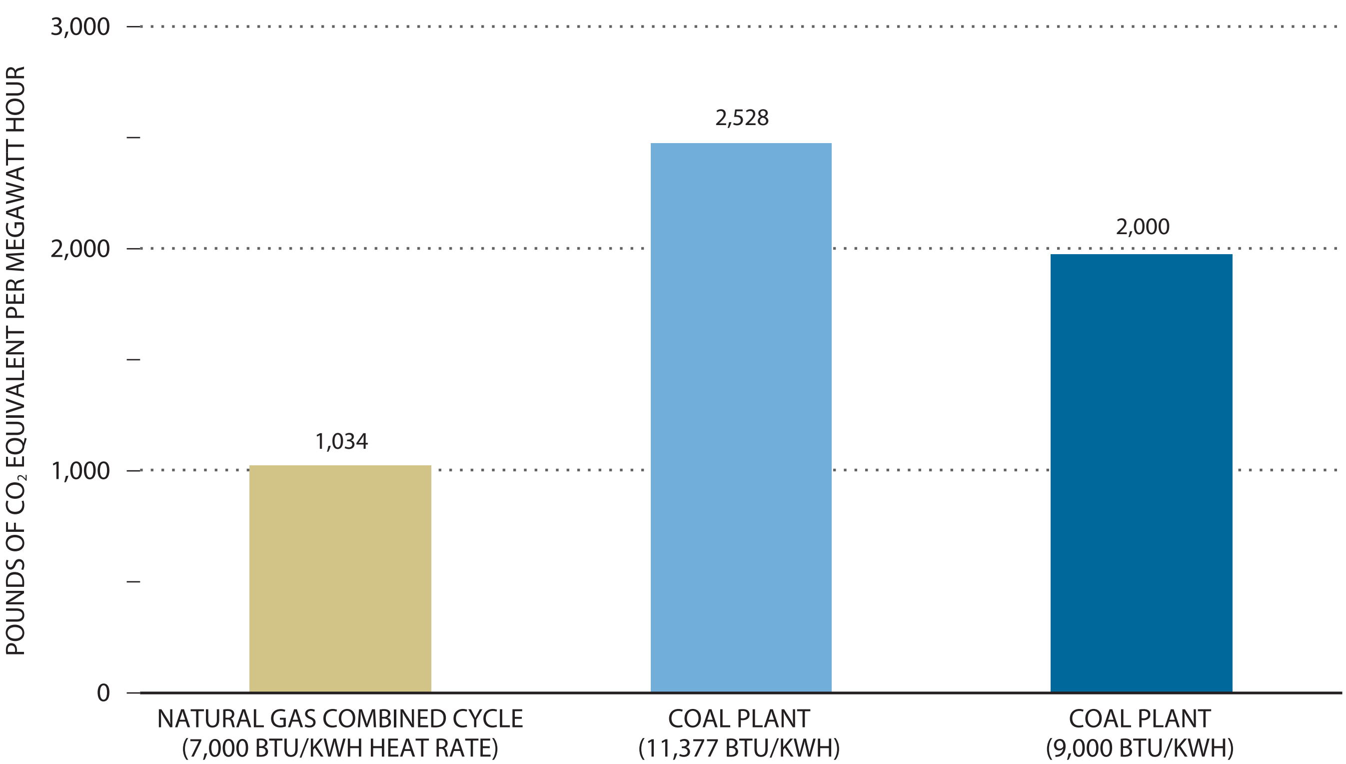


Table 4-3. Comparison of Life-Cycle Emission Rates in the Electric Power Sector

Natural Gas		
Efficiency (percent)*	Heat Rate (Btu/kWh)	NPC (lb CO_2e/MWh)
52	6,563	970
49	7,000†	1,034
28	12,189	1,800
Coal		
Efficiency (percent)‡	Heat Rate (Btu/kWh)	NPC (lb CO_2e/MWh)
38	9,000§	2,000
37	9,224	2,050
30	11,377	2,528

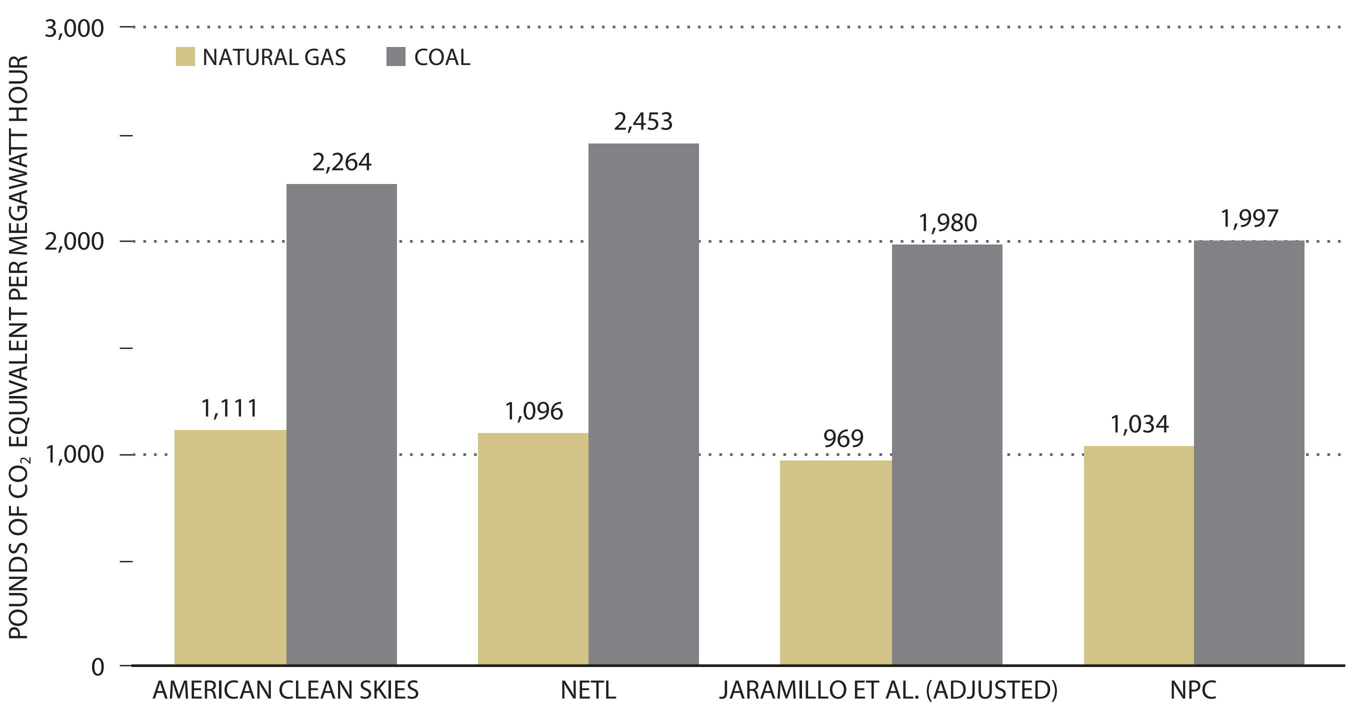
* Adjusted from 58–28% range noted in the Jaramillo et al. paper (see Footnote 35).

† 7,000 Btu/kWh – assumed nominal heat rate for a new NGCC plant.

‡ Adjusted from 37–30% range noted in the Jaramillo et al. paper (see Footnote 35).

§ 9,000 Btu/kWh – assumed nominal heat rate for a new coal plant.

Figure 4-11. Comparison of Life-Cycle Emission Rates in the Electric Power Sector



Note: National Energy Technology Laboratory rates based on average coal and gas life-cycle emissions. NPC and Jaramillo et al. based on nominal heat rates of 7,000 Btu/kWh (gas) and 9,000 Btu/kWh (coal).

during combustion. Over the 100-year frame, the GHG footprint is comparable to that for coal … fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation…. However, this does not greatly affect the overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity."

There are three major factors that contribute to the higher GHG footprint for natural gas, as computed by Howarth et al.:

- The use of a higher 20-year GWP of 105 instead of a 100-year GWP
- Potential overestimation of actual emissions due to the use of "lost and unaccounted for gas" (LAUF) as a proxy to arrive at "1.4% to 3.6% leakage of gas during transmission, storage, and distribution" (about 38–45% of the total leakage of methane computed by Howarth et al.)
- Potentially an overestimation of emissions from well completions (about 24–52% of the total leakage).

The methodologies employed by Jaramillo et al. (and NPC) and also others, such as the American Gas Association and American Clean Skies Foundation, are based on annual average emissions and energy production or consumption. The NPC estimates here use the revised, higher EPA annual emissions estimates and EIA's estimates of natural gas production in 2009. Employing these methods, the NPC estimates the total methane emissions to be 2.2% of the total gross production – an estimate consistent with other independent estimates and significantly less than the Howarth estimates.[44,45]

LAUF is essentially the metered difference in natural gas delivered into and out of the transmission and distribution pipeline system less fuel employed for compressor operations. The EPA in developing the Subpart W rule for GHG reporting for oil and gas facilities concluded that LAUF was not a good "surrogate" since there are several factors associated with LAUF, "such as inaccuracies of gas measurement."[46]

The EPA estimates uncontrolled methane emissions from well completions (and workovers) to be about 120 billion cubic feet (Bcf), or 0.46%, of the 2009 gross production. As noted, these are uncontrolled estimates and do not account for "green completions" to reduce such emissions. Wood Mackenzie[47] estimates that Howarth et al. may have "overestimated the average volume of natural gas vented during the completion and flowback stages by 60%–65%" and that the practice of green completion is widely followed by many operators in various unconventional shale plays.

The end-use combustion of gas or coal accounts for 79% of life-cycle emissions for gas and 94% in case of coal.[48] Hence, "leakage" or emissions from the upstream (i.e., production, processing, transportation/storage, and distribution) has to be about 10% of the 2009 gross production for the life cycle of coal and gas to be similar.[49] Efficiency of the end-use equipment can play a significant role in the LCA. Howarth et al. also do not employ the end-use efficiencies associated with natural gas equipment (e.g., efficiency of an NGCC plant versus a coal plant). The NPC finds the life-cycle GHG emissions from the end-use of natural gas at new NGCC plants in the power sector are approximately 50–60% lower than coal-based generation based on the range of current U.S. power plants.

Methane Reduction Programs and Technologies

The EPA Natural Gas STAR program is a voluntary industry-government partnership that has encouraged reduction of over 900 Bcf of natural gas (over 400 million $MtCO_2e$) through the application of over

44 Ramon Alvarez, April 19, 2011, Environmental Defense Fund (EDF) at http://blogs.edf.org/energyexchange/2011/04/19/mixed-news-coverage-of-report-on-climate-pollution-from-natural-gas-underscores-the-need-for-better-data/.

45 See pages 2–4 of document EPA-HQ-OAR-2009-0923-0086 in the EPA docket for GHG reporting rule. http://www.regulations.gov/contentStreamer?objectId=0900006480afa1c2&disposition=attachment&contentType=pdf.

46 Mandatory Greenhouse Gas Reporting Rule Subpart W – Petroleum and Natural Gas: EPA's Response to Public Comments. Response to Comment No. EPA-HQ-OAR-2009-0923-1059-12, page 323.

47 Wood Mackenzie, Regional Gas and Power Services Insight, May 2011.

48 On a heat input basis (lb/MMBtu).

49 On a 100-year time period (GWP 25). See Section IV of Topic Paper #4-2, "Life-Cycle Emissions of Natural Gas and Coal in the Power Sector," for the "cross-over" analysis.

150 cost-effective technologies since 1993. In addition to the Natural Gas STAR program, segments of the industry are subject to National Emission Standards for Hazardous Air Pollutants rules. In 2009, EPA estimates over 62 million $MtCO_2e$ of reduction via the EPA Gas STAR program and about 19 million $MtCO_2e$ via regulations such as National Emission Standards for Hazardous Air Pollutants.[50]

The Natural Gas STAR program has been very successful in technology transfer between EPA Gas STAR members. Recommended practices, including cost-benefit analysis, have been developed by the EPA[51] and the California Air Resources Board.[52] The EPA Gas STAR program represents over 60% of the natural gas industry and its specific breakdown is as follows:[53]

- Production Sector: 30 Gas STAR production partners responsible for approximately 45% of total gas and oil production in the United States.
- Processing: 12 Gas STAR processing companies accounting for approximately 52% of total gas processed in the United States.
- Transmission: 32 gas transmission companies responsible for approximately 72% of total gas transported in the United States.
- Distribution: 55 local distribution companies responsible for approximately 69% of gas distribution in the United States.

Hence, greater penetration of these technologies in the industry will likely reduce methane emissions. A 2010 Government Accountability Office report showed that around 40% (around 50 Bcf/year, or over 22 million $MtCO_2e$) of currently vented and flared natural gas on federal leases alone could be economically captured, with current available control technologies.[54] Reducing methane emissions in natural gas systems has resulted in significant savings for companies[55]; it will also increase the attractiveness of the downstream natural gas product to end users and also reduce loss of federal royalty payments (on leased federal lands and waters).

Conclusions

- The EPA's 2009 inventory shows about 130% increased methane emissions from the natural gas sector relative to its 2008 report. Based on the inventory, methane emissions from the U.S. natural gas systems[56] are about 3% of the total U.S. GHG emissions.
- As demonstrated by the significant revisions in the EPA estimates, industry comments on the inventory, and recent estimates independently computed by Howarth et al., the methane emissions from the natural gas sector will need refinement and improvement through actual measurements or development of robust, representative factors.
- Applying the EPA methane projections from the 2009 inventory report, the life-cycle GHG emissions for natural gas are about 35% lower than coal on a heat-input basis (expressed as pounds of CO_2 equivalent per million Btu).
- For efficiencies typical of new coal- and natural gas-fired plants in the United States, the natural gas-fired plants are about 50% lower in GHGs (expressed as pounds of CO_2 equivalent per megawatt hour [MWh]) than a supercritical pulverized coal plant on a life-cycle basis and about 60% lower than the older subcritical pulverized coal plants still in use.

50 ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories, Tables A-125 and A-126. http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Annex-3.pdf. Methane reductions converted to CO_2e based on GWP of 25.

51 See Environmental Protection Agency's Natural Gas STAR Program information found at: http://epa.gov/gasstar/tools/recommended.html.

52 See the California Air Resources Board's information on GHG reductions at: http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm#Methane.

53 As of May 2011. EPA via electronic mail, May 9, 2011.

54 United States Government Accountability Office (GAO), "Federal Oil and Gas Leases, Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases," GAO-11-34, October 2010, http://www.gao.gov/new.items/d1134.pdf.

55 GAO-11-34, page 23.

56 Natural gas systems include production, processing, transmission, storage, and distribution segments of the industry. 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. See page 3-43 of "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009," USEPA 430-R-11-005, April 2011. http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

- The NPC estimates the total methane emissions from the U.S. natural gas systems to be 2.2% of the total gross production, an estimate consistent with other independent estimates.
- Other estimates have shown that NGCC plants have 99% lower SO_2 and mercury emissions and about 82% lower NOx emissions relative to a pulverized coal unit on a life-cycle basis.[57]
- NPC estimates are within the range of similar life-cycle emissions estimates conducted by other entities, with the exception of Howarth et al.
- Greater penetration and applications of various EPA Gas STAR technologies provide a proven avenue to reduce methane emissions.

Recommendations

1. More Rigorous Analysis Should Be Undertaken

While the NPC analysis contained in this report provides a life-cycle estimate of GHG emissions for natural gas, a more rigorous analysis should be undertaken making use of the most recent EPA and EIA information on emissions and natural gas resources and also incorporating robust uncertainties in the emissions estimated. Further estimation refinements and improvements are already underway,[58] including comprehensive nationwide measurements that are currently being undertaken by facilities subject to EPA reporting rules. The EPA should analyze these comprehensive compliance measurement data to develop future emission factors for use in LCAs to assist in the development of future policies for the sector.

2. Industry Should Continue to Adopt and Employ EPA Gas STAR Technologies to Reduce Methane Emissions Along the Natural Gas Value Chain while Maintaining Safety and Reliability

Emissions of natural gas occur within natural gas systems prior to end-use (production, processing, and transportation) to facilitate safe and reliable operations (e.g., operations of actuators, control devices, and relief valves).[59] EPA Gas STAR participation is about 60%; regardless of the uncertainty with the emissions estimates and measurements, continuing to adopt and employ EPA Gas STAR technologies[60] or similar technologies will reduce methane emissions along the natural gas value chain while maintaining safety and reliability. Barriers to adoption of these technologies should be evaluated and the industry and government must work together to overcome these barriers.

NATURAL GAS END-USE TECHNOLOGIES

With the definition of a 2005 baseline year and a comparative examination of GHG emission forecasts complete, the study identified natural gas end-use technologies in power, industrial, commercial, and residential sectors that could reduce GHG emissions beyond those included in the baseline. Natural gas-driven GHG emission reduction opportunities in the transportation fuels sector using natural gas, battery, electric, and hydrogen fuel cell vehicles will be covered in the parallel NPC Future Transportation Fuels study. To calculate the cumulative impact of identified technologies would require an integrated modeling approach that avoids double-counting. Notwithstanding the challenges such an effort might require, new and integrated modeling was outside the scope of this working paper. Hence, the results in this subchapter present a palette of options for natural gas end-use technologies, not a prescriptive path.

Methodology[61]

Data were gathered from 35 publicly available academic and industry studies that described 61 emissions reduction cases that quantified the potential GHG reduction volume and associated cost from natural gas end-use technologies.[62] The final study sample set consisted of 15 studies detailing 15 end-use technologies in 32 cost-volume data points after

57 National Energy Technology Laboratory, *Life Cycle Analysis: Power Studies Compilation Report,* January 2011.

58 http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Chapter-3-Energy.pdf. See page 48 (Planned Improvements).

59 As defined by U.S. EPA in the *U.S. Greenhouse Gas Emissions and Sinks 1990-2008,* IPCC Source Category 1B2b.

60 EPA, "Natural gas STAR Program: Accomplishments." Last updated December 14, 2010. http://epa.gov/gasstar/accomplishments/index.html.

61 Full description of the methodology, results, and conclusions can be found in Topic Paper #4-3, "Natural Gas End-Use GHG Reduction Technologies."

62 Studies reviewed did not consider reduction potentials attributed to non-GHG regulations identified in the section of this chapter entitled "Impact of Non-GHG EPA Rules on the Power Sector."

screening for quality and relevancy as described below. After determining the study sample set, the research team tabulated data for each natural gas end-use technology across three attributes:

- Projected GHG emission reduction **volumes**[63]
- The projected abatement **cost**[64] associated with those emission reduction volumes
- A proxy measure of the **uncertainty** of these projections.

Technologies were subsequently sorted into three categories (appliances and equipment, power generation, industrial applications) and 15 discrete subcategories (Table 4-4). An "indicative" potential of each subcategory was summarized by calculating the volume-weighted average cost (VWAC) and cost-weighted average volume (CWAV) for each technology. VWAC is the average marginal cost of avoiding emission of 1 metric ton of CO_2e by deploying the end-use technology in question, weighted in proportion to the corresponding volumes projected in the study sample set. CWAV is the average volume of potential annual emission reductions projected to result from deploying the end-use technology in question, weighted in proportion to the corresponding costs projected in the study sample set. For subcategories with only one study case, the VWAC and CWAV equaled the cost and volume findings of the single study case. For technologies with multiple data points, an uncertainty score was computed using a proxy metric for the variance of projected results across available studies for each technology, calculated using a geometric average.[65] The uncertainty metric is intended to encapsulate the dispersion of volume and cost projections among the studies.

While the study-of-studies methodology required acceptance of the different assumptions used in the different forecasts, disparate units of measure could not be tolerated. Thus, cost and volume estimates had to be normalized. Study data expressed in different units (e.g., dollar-years or reduction target years) or using different metrics (e.g., cumulative rather than annual emissions reductions) were normalized using simple, linear conversion factors. In cases where published reports did not stipulate, specify, or disclose parameters necessary to evaluate whether technologies could be deemed equivalent to technologies addressed in other studies, the research team contacted study authors to obtain additional data and clarifications. The research team excluded those studies where authors did not respond to data requests or data gaps could not be closed. In cases where the research team could not obtain usable, quantitative data for potentially significant natural gas end-use technologies, the research team prepared reasonable estimates of potential reduction volumes and marginal costs.[66]

63 For the purposes of this section, volume refers to the annual quantity of GHG reductions in metric tons of CO_2e below reference case emissions.

64 For the purposes of this section, cost refers to the quantity in 2009 dollars of avoiding 1 metric ton of CO_2e.

65 Uncertainty scores were calculated on a geometric basis using $U = \sqrt{((Cmax - Cmin)^2 + (Vmax - Vmin)^2)}$

Findings

- Table 4-5 provides GHG emissions reduction potentials for the 15 end-use technologies in the various end-use sectors and abatement costs. Cost-weighted average volumes by 2030 for the technologies within the sample set ranged from 7 million $MtCO_2$e per year (commercial appliance conversions) to 571 million $MtCO_2$e per year (natural gas CCS) with a median of 80 million $MtCO_2$e per year. Volume-weighted average costs for the technologies within the sample set ranged from negative \$40/$MtCO_2$e (new industrial appliances and commercial combined heat and power [CHP]) to \$317/$MtCO_2$e (fuel cell generation) with a median VWAC of \$38/$MtCO_2$e.
- Some combination of these 15 technologies may achieve reductions up to 864 million $MtCO_2$e by 2030 (Figure 4-12). This amounts to roughly 12% of GHG emissions in 2005; reductions beyond this will likely require utilization of other technologies and options not identified in this report. While the sum of all reduction potentials of each technology is greater than 864 million $MtCO_2$e (Table 4-5), the range provided in Figure 4-12 was computed by selecting the minimum and maximum value per end-use sector (power, residential, commercial, and industrial) to avoid potential double counting in each sector.

66 For further details on reduction volume and marginal cost estimates, see Topic Paper #4-3, "Natural Gas End-Use GHG Reduction Technologies."

Table 4-4. Natural Gas End-Use Technologies

Sector/Technology	Definition
Residential	
Appliance and Equipment Conversions New Appliances and Equipment	Heating, cooling, and water appliances and equipment that serve residential buildings and are fueled by natural gas.
Power Generation	
Build New Combined Cycle Gas Turbine	An electricity generation technology in which the exhaust of a combustion turbine is linked to a heat recovery steam generator and a steam turbine to produce additional electric output.
Natural Gas Carbon Capture and Sequestration	Use of technology to physically separate CO_2 from other gases either pre-combustion or post-combustion. Captured CO_2 is then disposed of via sequestration or conversion into other compounds.
CHP, Commercial CHP, Industrial	Combined heat and power (CHP) is a form of on-site generation in which a heat engine or a power station simultaneously generates both electricity and useful heat. Heat output can be used for industrial and commercial processes and power consumed on-site with excess power sold to the grid.
Fuel Cells	Form of on-site generation in which electricity conversion occurs via an electrochemical reaction.
Redispatch	Run (dispatch) existing natural gas combined cycle electric generation ahead of higher emitting coal-based generation.
Refuel	Conversion of existing coal- or oil-fired boiler to burn natural gas as a replacement or supplement to coal or oil.
Repower	Conversion of existing coal- or oil-fired generating station by retaining a portion of steam generation equipment for use with new natural gas combustion turbine or combined cycle equipment.
Industrial	
Efficiency	Industrial facilities can improve the efficiency of their natural gas-fueled processes and systems through such measures as waste heat recovery, improved maintenance, process energy monitoring, and new processes.
Fuel Switching	Industrial facilities in energy-intensive industries, such as cement and metals, switch to natural gas for thermal energy.
New Appliances and Equipment	Heating, cooling, and water appliances and equipment that serve industrial facilities and are fueled by natural gas.
Commercial	
Appliance and Equipment Conversions New Appliances and Equipment	Heating, cooling, and water appliances and equipment that serve commercial buildings and are fueled by natural gas.

- Irrespective of cost, natural gas with CCS presents the largest potential GHG reduction volume, with a potential 23% reduction in the power generation sector's emissions. No other individual end-use technology can reduce its sector's emissions by more than 12% below 2030 reference case levels (and most technologies by themselves only reduce total sector emissions by 3–4%).

Table 4-5. GHG Emissions Reduction Potentials per Technology versus Projected Sector Emissions in 2030

Sector/Technology*	Average Volume, Million $MtCO_2e$†	Average Cost, $/$MtCO_2e$‡	Sector Emissions, Million $MtCO_2e$,§ 2030	Reduction Potential as Percentage of Sector's Emissions#
Power Generation				
Natural Gas Carbon Capture and Sequestration (CCS)	571	$79	2,533	23%
Refuel	110	$37		4%
Redispatch	95	$40		4%
Build New Combined Cycle Gas Turbine	89	$46		3%
Combined Heat and Power (CHP), Industrial	82	($15)		3%
Repower	80	$67		3%
Fuel Cells	75	$317		3%
CHP, Commercial	70	($40)		3%
Residential				
New Appliances and Equipment	150	($8)	1,255	12%
Appliance and Equipment Conversions	15	$7		1%
Commercial				
New Appliances and Equipment	84	($16)	1,261	7%
Appliance and Equipment Conversions	7	$49		1%
Industrial				
New Appliances and Equipment	59	($40)	1,578	4%
Fuel Switching	41	$38		3%
Efficiency	34	$41		2%

* Please see Table 4-4 for description of technologies.

† The average volume of potential emission reductions projected to result from deploying the end-user technology in question, weighted in proportion to the corresponding costs projected in the study sample set.

‡ The average marginal cost of avoiding emission of 1 metric ton of CO_2e by deploying the end-user technology in question, weighted in proportion to the corresponding volumes projected in the study sample set.

§ EIA's AEO2010 Reference Case projection for energy-related CO_2 emissions in 2030 for relevant sector. For residential, industrial, and commercial sectors, emissions associated with electricity purchases are included.

\# The quotient of a technology's cost-weighted average volume (CWAV) and the total emissions of the corresponding sector.

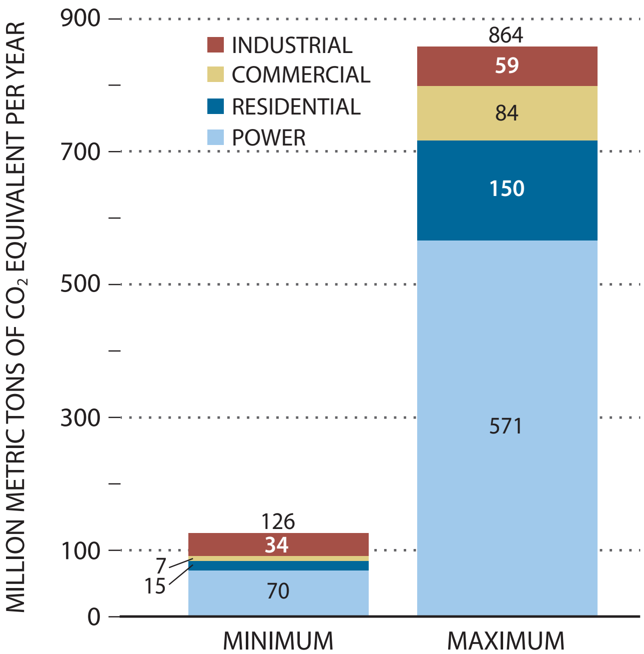
Limitations and Caveats:

a. The technology options or the indicated reductions above are not intended to represent cumulative reduction potential from the concurrent deployment of different technologies.

b. Considering limited publicly available data to meet the study goals, the research methodology required the research team to exclude studies from consideration for two primary reasons: (1) The studies "bundled" technology performance projections with policy assumptions and did not identify whether GHG emissions reductions derived from technology or policy; and/or (2) The studies did not include a complete set of volume and cost data for the technologies they addressed. As a result, the results presented above from a limited data set of studies analyzing these end-use technologies.

c. In order to common-size data for comparison purposes, the research team had to make simplifying assumptions. These simplifying assumptions produce results that are not intended to suggest precise costs and volumes, but to provide broad estimates for comparison purposes.

Figure 4-12. Illustration of Range of Potential GHG Emissions Reductions in the End-Use Sectors through Natural Gas Technologies (2030)



- Academic and industry literature examining the potential GHG reductions and costs associated with end-use natural gas technologies varies by technology in robustness and quality, limiting the ability to comprehensively assess the role of natural gas end-use technologies in reducing GHG emissions.

IMPACT OF NON-GHG EPA RULES ON THE POWER SECTOR

In the United States today, approximately 100 GW, or 32%, of coal-fired electric generating capacity is over 40 years old, and 14% is greater than 50 years old.[67] The power sector will be subject to compliance with several key environmental rules over the next several years (Table 4-6), including the National Emissions Standards for Hazardous Air Pollutants regulations under Section 112 of the Clean Air Act requiring the application of Maximum Achievable Control Technology (MACT), and potential regulations regarding cooling water intake structures and coal combustion byproducts (coal ash). Some of the new rules have been or will be finalized in the next year or two and compliance is set to begin as early as next year for some rules and by mid- to late decade for others. Compliance costs associated with these regulations may cause some owners to retire inefficient coal-fired power plants rather than retrofit them to comply with the new environmental rules.[68]

While significant uncertainty remains surrounding the level of stringency, required emissions controls, timing of the rules, impact to grid reliability, and availability of engineering resources, several analysts have recently published research regarding the amount of coal plant retirements that may occur as a result of these emerging environmental regulations. These reports[69] indicate that an average of 58 GW of coal capacity may retire by 2020, representing a potential increase in natural gas-fired generation of about 295 terawatt hours (TWh) versus 2010 total natural gas generation of about 981 TWh.[70] These results and reductions are specific to this section, which may differ from results in earlier sections that analyzed the impact of carbon constraints without a focus on EPA regulations. These sections operate independently and should not be combined in any manner. The review of these recent reports regarding potential coal plant retirements is discussed in more

67 M. J. Bradley & Associates LLC, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," August 2010.

68 These emerging environmental rules are already causing some coal plant owners to retire their facilities. For example, the Sierra Club reported in a December 22, 2010, press release ("2010, Outlook Dimmed for Coal") that utilities announced 12 GW of coal plant retirements in 2010. However, offsetting these announcements were roughly 6.7 GW of new coal plant capacity that came online in 2010 (and additional coal plant capacity additions of roughly 6 to 7 GW are expected in 2011-2012). See Erik Shuster, "Tracking New Coal-Fired Power Plants," National Energy Technology Laboratory (NETL), January 14, 2011.

69 The reports that were reviewed typically examine the collective impact of multiple environmental rules (or a subset of these rules) rather than any one rule individually. The EPA, however, has recently provided its estimates for how individual rules may impact coal retirements. For example, the EPA projects that about 0.5–1.6 GW of coal capacity would likely retire due to the Transport Rule and natural gas generation would increase only by 1–2% relative to a base case without the Transport Rule. With respect to the Utility MACT rule, the EPA projects a retirement of 9.9 GW of coal-fired capacity (3% of all coal-fired capacity and 1% of total generation capacity in 2015) by 2015 in addition to the 5 GW in the EPA's Base Case. Since the EPA completed their analysis of the MACT rule after the finalization of the analysis presented in this section, the EPA results were not incorporated in this section (MACT rules were proposed on March 16, 2011).

70 EIA's Electric Power Monthly.

Table 4-6. Background Information on Potential EPA Regulations

CATR*	HAPs MACT†	Water‡	Coal Ash§
The Clean Air Transport Rule (CATR) was designed to improve air quality in the eastern United States and limit interstate air pollution transport. The CATR requires 31 states and the District of Columbia to reduce power plant sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions. Combined with other state and EPA actions, the CATR would reduce SO_2 and NOx by 71% and 52% below 2005 levels, respectively. The CATR replaces the Clean Air Interstate Rule that was vacated in 2008.	Hazardous Air Pollutants (HAPs) Maximum Achievable Control Technology (MACT) are standards designed to reduce HAPs emissions, most notably, mercury. The EPA proposed MACT standards for coal and oil utilities on March 16, 2011, and plans to finalize rules by December of 2011. In general, the research reports analyzed in this report assumed that some combination of flue gas desulfurization (FGD, or a scrubber), activated carbon injection, and a fabric filter will suffice.	This section of the Clean Water Act "requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." The EPA proposed these rules based on Section 316(b) of the Clean Water Act on March 28, 2011, and plans to finalize the rules by July 2012.	Currently, the EPA does not regulate coal combustion byproducts (coal ash). However, the Resource Conservation and Recovery Act (RCRA) gave the EPA the power to control hazardous wastes and the framework for managing non-hazardous wastes. The EPA has proposed rules to regulate coal ash as either a hazardous or non-hazardous waste. Final rules are expected in early 2012.

* On July 6, 2011, the U.S. Environmental Protection Agency finalized the Cross-State Air Pollution Rule (CSAPR) (known as the Clean Air Transport Rule when it was proposed) as the formal replacement for the Clean Air Interstate Rule. The final CSAPR was published in the Federal Register (76 FR 48208) and is available at http://www.gpo.gov/fdsys/pkg/FR-2011-08-08/pdf/2011-17600.pdf. Due to late release of the CSAPR, the NPC study did not analyze the impact of the CSAPR to the power sector.

† The proposed rule can be found at http://www.gpo.gov/fdsys/pkg/FR-2011-05-03/pdf/2011-7237.pdf.

‡ The proposed rule can be found at http://www.gpo.gov/fdsys/pkg/FR-2011-04-20/pdf/2011-8033.pdf.

§ The proposed rule can be found at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-0352.

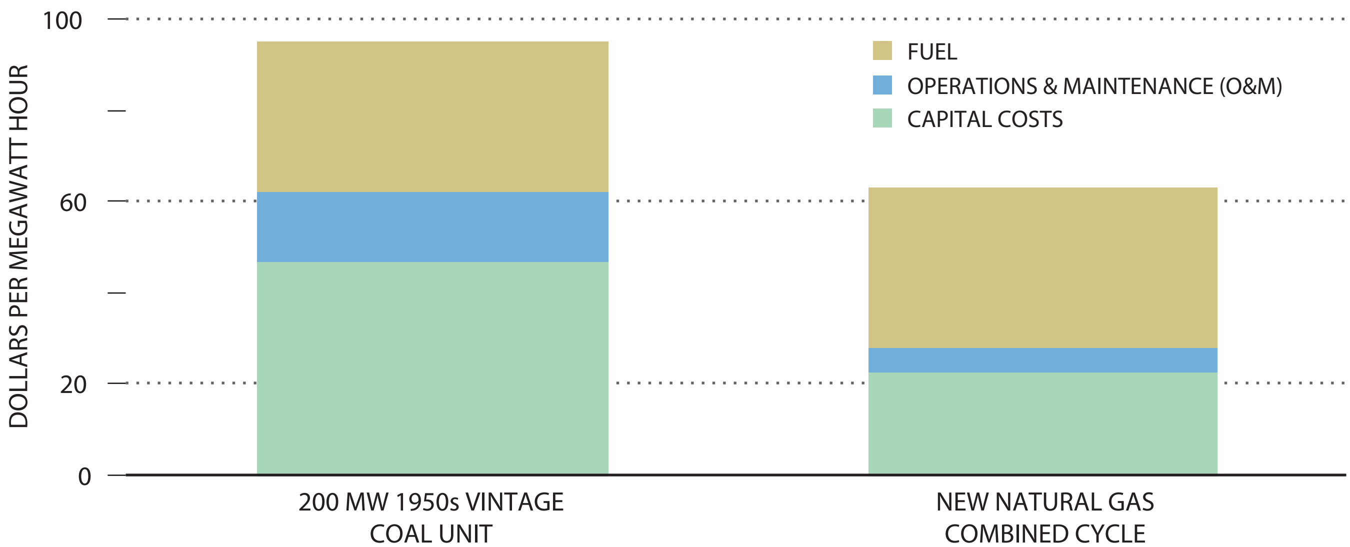
detail in the "Results" section of this chapter. The next section discusses the factors that influence the coal plant retirement decision.

Retirement Decision

A plant owner's decision to retire an existing coal unit will depend on a variety of factors, including the plant's age, condition, and operating history, its efficiency, the cost of the emission controls required, the expected cost of its fuel supply, electric reliability and transmission issues, regional electric market conditions, future CO_2 prices, and expected natural gas prices. For unregulated plants, the retirement decision will depend on the overall expected profitability of the plant (including the costs of retrofitting the plant) while for regulated units, the retirement decision will depend on the comparison of the expected cost of continuing coal plant operations relative to the expected cost of the alternative generating resource (e.g., from a gas-combined cycle or combustion turbine, or conversion to biomass). When natural gas is relatively abundant, favorable fuel economics and relative lack of environmental control requirements may make natural gas-fired power plants an economical choice and greatly influence a power company's decision to retire or retrofit its coal plants.

Figure 4-13 illustrates the retirement decision facing a regulated coal unit. It compares the levelized cost of electricity of two representative facilities: a 200-megawatt coal facility commissioned in 1950 and a new NGCC facility. On a $/MWh basis, the cost to retrofit a coal facility requiring controls for SOx, NOx, mercury, and coal ash is about 50% higher than the cost of a new NGCC facility. Although the short-run marginal cost of a retrofitted coal facility may be lower than a new NGCC facility, that same coal facility – which may be nearing the end of its economic life due to

Figure 4-13. Levelized Cost of Electricity Due to Non-GHG Rules



Assumptions:

1. Retrofit and new build capital cost and O&M assumptions are from Environmental Protection Agency estimates.
2. Coal combustion residual (CCR) capital cost is from industry estimates.
3. Uncontrolled coal unit (200 MW) requires flue gas desulfurization (FGD) + selective catalytic reduction (SCR) + CCR: Capital cost – ~$1,450/kW; retrofit life – 15 years; 11,000 Btu/kWh heat rate; $3/million Btu coal price.
4. Natural gas combined cycle: Capital cost – ~$1,000/kW; life – 30 years; 7,000 Btu/kWh heat rate, $5/million Btu gas price.

Source: American Electric Power, May 2011.

increasing maintenance requirements or potential CO_2 pricing in the future – may need to recover its capital expenditures over a shorter period of time than the useful life of the environmental equipment.

The relationship between coal and natural gas prices also factors into the retirement decision in that it impacts the operating margins of coal units as well as the utilization (capacity factors) of both coal and gas units (i.e., the number of hours of the year the units are dispatched to serve load). In a recent paper,[71] Richard Schmalensee and Robert N. Stavins concluded that "[r]ecent market trends (fuel price spread) and technological developments (unconventional resources) have substantially lowered the cost of transitioning from coal-fired generation to alternative power sources."

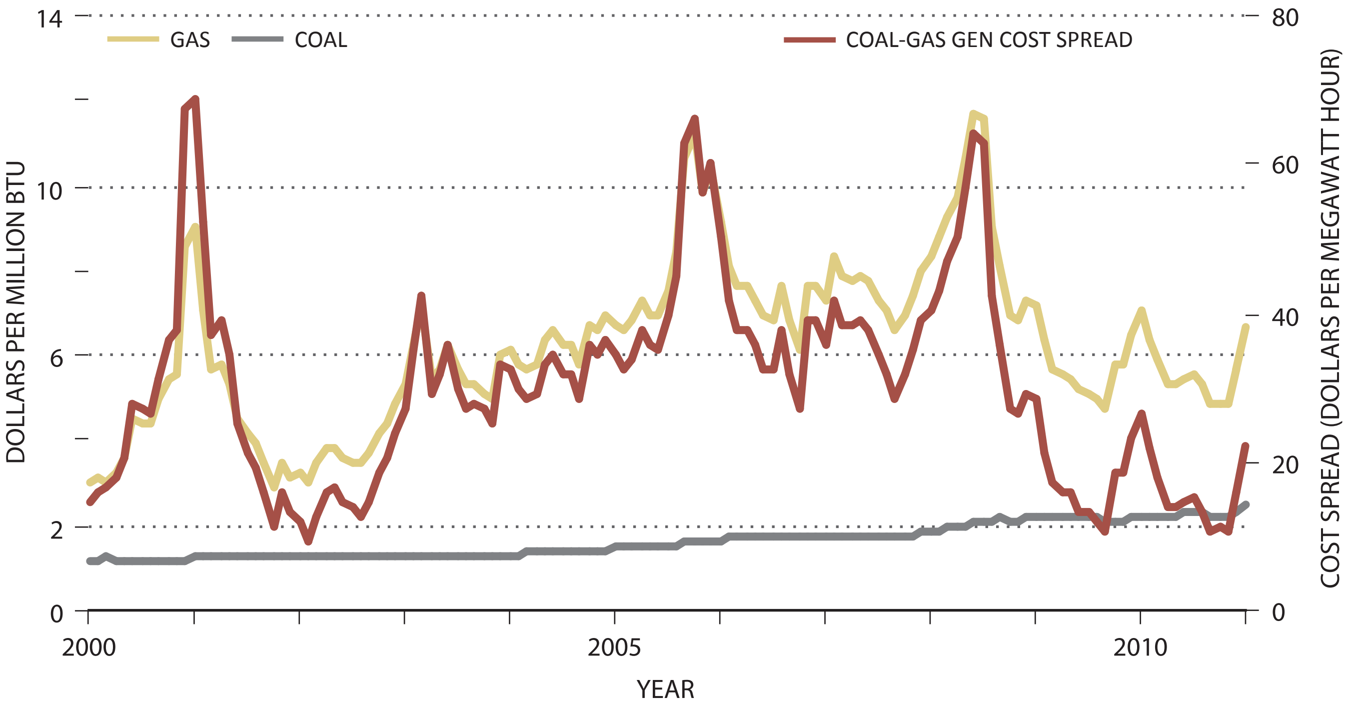
Figure 4-14 displays the historical relationship between delivered coal and natural gas prices, and the derived coal-gas electric generation cost difference; the generation spread has averaged about $30/MWh. However, the recent decline in natural gas prices (brought about by abundant reserves and increasing domestic production) and increasing coal prices have reduced the coal-natural gas electric generation price spread relative to the levels experienced during most of the prior decade.

Since natural gas-fired generation is frequently the marginal (price-setting) source of electricity in many regions at different times of the year, lower natural gas prices may result in lower power prices.[72] If lower power prices could be sustained (due to low natural gas prices or excess capacity conditions in power markets), a coal facility's opportunity to recover the capital cost of retrofits is further deteriorated (especially if these low gas and power prices result in low coal plant capacity factors). In weighing these factors, many power plant operators may opt for plant retirement rather than retrofit their facilities that have reached the end of their useful life.

71 Richard Schmalensee and Robert N. Stavins, "A Guide to Economic and Policy Analysis of EPA's Transport Rule," March 2011, pages 16-17.

72 Federal Energy Regulatory Commission Electric Power Markets, see region-specific information (http://www.ferc.gov/market-oversight/mkt-electric/overview.asp).

Figure 4-14. Megawatt Hour-Weighted Fuel Costs of Generation and Coal-Gas Generation Cost Spread



Sources: FERC Form 1; EIA 412; RUS 412; EIA 906/923; and Ventyx Energy Velocity.

Methodology

To conduct this analysis of the potential amount of coal plant retirements, these broad steps were taken:

- Compiled relevant studies and extracted available data[73]
- Interviewed study authors to better understand their analysis and fill data gaps[74]
- Computed ranges and averages of key statistics across all studies, including estimated coal plant capacity at risk for retirement, lost coal plant generation from retiring plants, CO_2 emission reductions, and increased natural gas demand.

The 12 studies reviewed had varying assumptions and approaches. Some studies conducted qualitative assessments (e.g., filtering by age or lack of control requirements) while other studies conducted integrated energy and emissions modeling. As a study of studies, the team paid particular attention to the differences in key variables among the studies: regulations/policies analyzed (e.g., CATR, HAPs MACT, coal ash, cooling water intake, and GHG regulation), base years, target years, heat rates, energy prices, modeling methodology, and control technology options and costs.

Results

The average estimated coal generating capacity retired through 2020 across all studies (regardless of scenario) is 58 GW, or roughly 18% of the 316 GW of total U.S. coal-fired generation capacity (Figure 4-15).[75] All of the studies make the assumption that natural gas-fired generation will replace some or all of the retired coal generation capacity and, as a result, find (on average): a natural gas-fired generation increase of 295 TWh, with a natural gas

73 Twelve studies were used; the sample included research from private consultants, investment banks, trade associations, and the North American Electric Reliability Council.

74 Five research firms that conducted complex, integrated modeling of the impact of the new environmental rules on the U.S. coal-fired generation fleet were interviewed.

75 EIA's Electric Power Annual reports coal net-winter capacity of about 316GW; see http://www.eia.gov/cneaf/electricity/epa/epat1p2.html.

consumption increase of 2.2 trillion cubic feet (Tcf) per year (6 billion cubic feet per day), or about 10%, of current total U.S. natural gas demand. Additionally, studies find, on average, power sector GHG emissions fall by 254 million $MtCO_2e$, or about 11%, of the 2005 power sector GHG emissions.[76]

Intra-Study Themes

While analyzing these studies in aggregate, four important themes emerged:

1. **Stringency of Non-GHG Regulations**

   Retirements are positively correlated to the stringency and the number of regulations applied to modeling exercises – i.e., cases considering more uncertain regulations (e.g., coal ash and cooling water intake structures) – in addition to more certain regulations (CATR and HAPs MACT) generally saw increased retirements.

2. **Carbon Constraints**

   Retirements are positively correlated to price on carbon – i.e., cases with higher carbon prices saw increased retirements. Conversely, cases with lower (or zero) carbon prices had lower retirements.

3. **Natural Gas Prices**

   Retirements are negatively correlated to natural gas prices – i.e., as natural gas price projections increase, the number of retirements decline, and vice versa.

4. **Control Technology Costs**

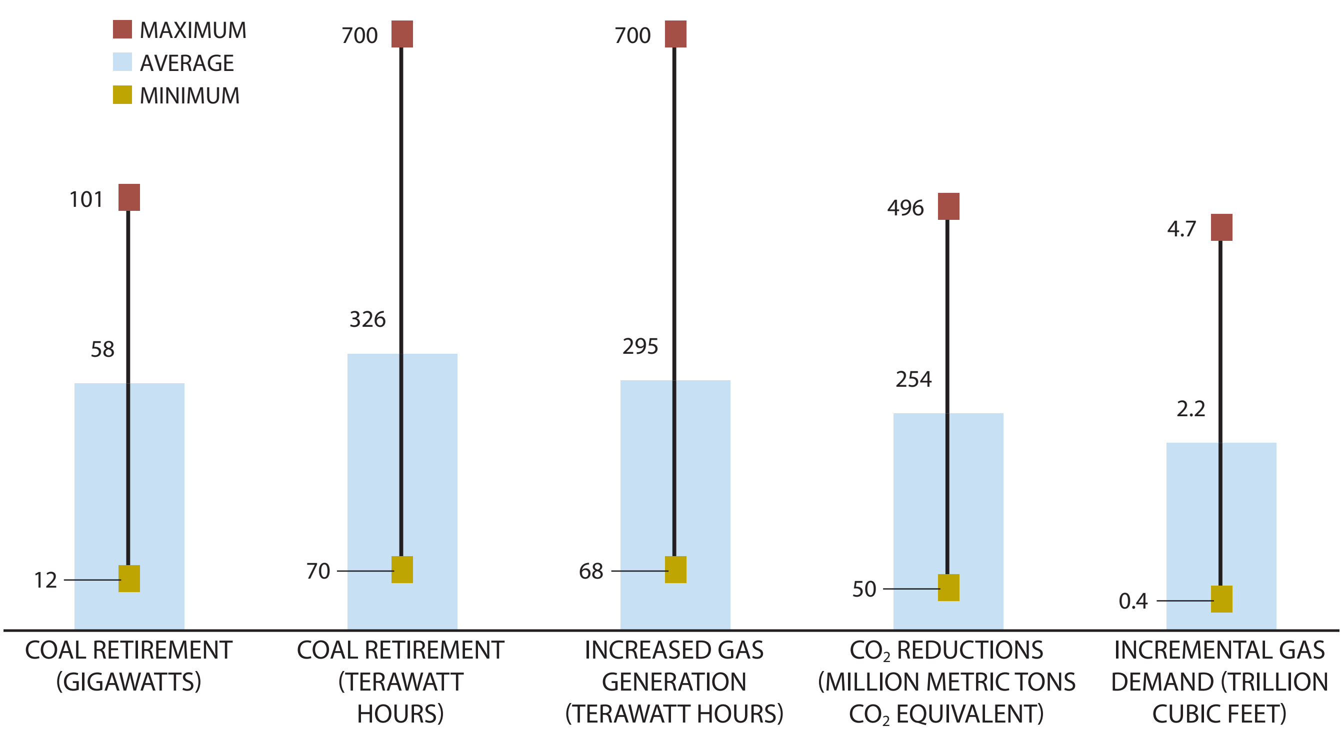
   Retirements are positively correlated to control technology costs – i.e., the more expensive it is to comply with any or all regulations/policies, the greater the retirements.

Other Considerations

As per the purpose of these rules, SO_2, NOx, and mercury emissions will decrease, even if only accounting for the impact of retiring coal facilities. The studies

76 Reductions are specific to this section, which may differ from results in earlier sections that analyze the impact of GHG emissions constraints without a focus on EPA regulations.

Figure 4-15. Summary of Results – Average, Maximum, and Minimum Values across All Studies (2020)



Note: Only to scale within each statistic of interest.

reviewed did not provide the reduction potential for these pollutants; however, reductions can be extrapolated using fleet-wide average emission factors. Table 4-7 summarizes the reduction potential.

Limitations

Analyzing the impact of EPA regulations and carbon policy requires a comprehensive, dynamic modeling effort. This study of studies is not a substitute for such effort; rather, it is a collection of studies, some of which were conducted using modeling.

Additionally, two important topics in this report were not covered: the impact of coal plant retirements on the reliability of the electric system and the need for improved/additional natural gas infrastructure (including both midstream and transmission pipeline infrastructure) to support the increased demand created by new gas-fired power generation. There is literature that discusses these issues, but at this time, these important considerations are beyond the scope of this report.[77] The Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), the EPA, the Department of Energy (DOE), and individual public utility commissions (PUCs) and independent system operators (ISOs) should carefully analyze these important issues.

77 See the North American Electric Reliability Corporation's report (http://www.nerc.com/files/EPA_Scenario_Final.pdf), MJ Bradley's report (http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf), or CRA's report (http://crai.com/uploadedFiles/Publications/CRA-Reliability-Assessment-of-EPA's-Proposed-Transport-Rule.pdf).

POLICY CONSIDERATIONS

Given the abundance of natural gas supplies in the United States, natural gas can play a significant role in the energy consumption patterns of the country. Accelerated deployment of end-use natural gas technologies may offer an important opportunity for reducing future GHG and criteria pollutant emissions.[78]

Earlier sections reviewed the macro impacts of carbon constraints on natural gas demand, the EPA rules impacting coal-fired power plants, and the life-cycle GHG emissions of natural gas relative to coal. In general, increased natural gas supplies, along with new environmental regulations, make natural gas an attractive option as a fuel in the electric power sector in the near- to midterm, particularly as a replacement fuel if there are significant coal plant retirements. However, in a scenario requiring deeper, long-term emission reductions (e.g., 80% reduction of GHGs by 2050), the contribution that natural gas would make to a lower carbon fuel mix may be less certain.

Methodology

The analysis in this section is based on a review of policy options that examined the wide range of policies that the United States could adopt as well as policies specific to the 15 clusters of technologies identified in Table 4-4 that hold special promise for

78 The term "accelerated deployment" has been defined by the National Research Council (2009) as the deployment of technologies at a rate that would exceed the reference scenario deployment pace, but at a less dramatic rate than an all-out crash effort, which could require disruptive economic and life-style changes that would be challenging to initiate and sustain.

Table 4-7. Potential Annual Reductions in Sulfur Dioxide (SO_2), Nitrogen Oxides (NOx), and Mercury (Hg)

Total Potential Switch from Coal to Gas	295 terawatt hours		
Emissions (Short Tons)	**Sulfur Dioxide**	**Nitrogen Oxides**	**Mercury**
Coal Retirements	1.9 Million tons	0.9 Million tons	6.0 tons
Natural Gas Increases	0.0 Million tons	0.3 Million tons	0.0 tons
Avoided Emissions	1.9 Million tons	0.6 Million tons	6.0 tons

Note: Coal emissions factors for SO_2, NOx, and Hg – 13 pounds per megawatt hour (lbs/MWh), 6 lbs/MWh, and 4.1x10^-5 lbs/MWh, respectively. Natural gas emissions factors for SO_2, NOx, and Hg – 0.1 lbs/MWh, 1.7 lbs/MWh, and 0 lbs/MWh, respectively.

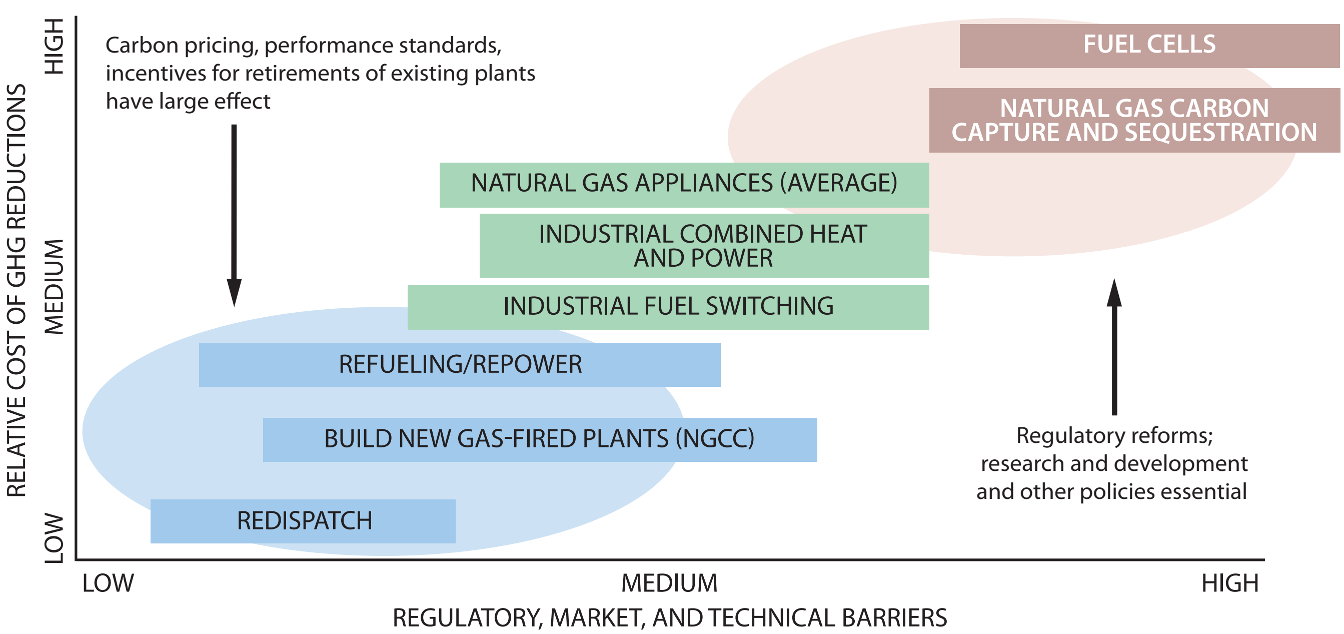
utilizing natural gas as a means of reducing emissions. The study team commissioned eight case studies by combining some of those clusters. Each of those eight case studies then evaluated policies and technologies along seven dimensions:

1. Maturity of technology
2. Cost effectiveness of technology at reducing CO_2 emissions
3. Public acceptance of technology
4. Regulatory and technical barriers
5. Role for government
6. Market barriers
7. Impact on jobs.

It is instructive to explore how the seven evaluation criteria interact. To illustrate those interactions, there are two criteria that are likely to have a big impact on policy design: the cost of a technology (closely linked to maturity and ability to achieve a given level of emissions reduction) and barriers. Figure 4-16 shows the results from plotting the eight case studies on these two dimensions for evaluation. Placement on this chart is sensitive to the definition of a relatively moderate cost as \$20–\$40/MtCO_2e out to 2030. For the bottom-left corner options, a carbon pricing policy can have a large impact if other market conditions favor a shift to gas (e.g., notably, lower natural gas prices). Indeed, if gas prices remain low relative to other fuels and conversion technologies, some opportunities in the bottom-left corner might unfold without much additional policy signal (but perhaps not to a degree to achieve substantial emissions reductions).[79] Carbon price projections in many legislative actions that have been considered in the 111th Congress are expected to start off within this price range. However, in some cases – e.g., higher carbon prices in the range of \$66–\$80/MtCO_2e – competing lower/zero emitting

79 Many other factors are at work as well, such as regulations that affect the ability of incumbent coal plants to compete. For example, the levelized cost of emission controls due to EPA rules associated with the transport of air pollution, ash from combustion, and cooling water regulation ("316(b)") could add up to \$25/MWh to the cost of coal-fired generation.

Figure 4-16. Evaluating Natural Gas Use Options According to their Cost and Barriers for Policies Designed to Achieve Low to Moderate Reductions in GHG Emissions



Notes: Low relative-cost of GHG reductions means that the technology is at or near competitive with low or zero cost per metric ton of CO_2 emissions avoided. High relative-cost of GHG reductions means that much larger policy signals – including possibly high costs for CO_2 emissions – would be needed for commercial deployment of the technology.
GHG = greenhouse gas; NGCC = natural gas combined cycle.

energy sources (e.g., nuclear and renewable energy sources) will become more attractive than natural gas.[80]

Deploying the technologies in the upper-right corner is much more complicated because they require a wider array of policies and higher price on carbon. RD&D incentives and subsidies will likely play a key factor in bringing many of these technologies to commercialization. However, accelerated deployment or even widespread adoption of these technologies will require overcoming significant regulatory, economic, and social barriers. For example lack of an adequate regulatory program, an overly stringent program, or public perception barriers may prevent the widespread penetration of natural gas CCS technology.

The potential emissions reduction varies by each technology. Table 4-5 indicates CCS for natural gas, and natural gas appliances offer the largest theoretical reduction potentials through the use of natural gas. Other technologies have lower long-term emissions reduction potential, but offer the prospect of emission reductions that could appear more quickly and may also be less costly.

Findings

The analysis leads to these main findings about the context in which deployment of natural gas technologies might be pursued as a policy objective:

- A portfolio of policies could enable accelerated deployment of several natural gas end-use technologies to effectuate both near-term and long-term emissions reductions.
- A price on carbon (implied or explicit) or similar regulatory action that recognizes and prices the environmental externalities of fossil fuel emissions will help to accelerate shifts from power generation that burns coal to generation technologies that rely on natural gas, including higher use of existing natural gas-fired power plants as well as the construction of new natural gas-fired power plants.
- Upcoming EPA regulations may result in substantial coal plant retirements, with corresponding increases in natural gas-fired generation and electric sector natural gas demand and decreases in carbon dioxide emissions.
- Even with a price on carbon, market and regulatory barriers are many and complicated. Such obstacles include social barriers – such as lack of education or information about the performance of technologies or public acceptance of infrastructure – that prevent their adoption. Some technologies, such as higher efficiency appliances, could save users money at present, yet are not adopted due to such barriers.
- For many opportunities, especially those in the power sector, the future role of natural gas depends heavily on the regulation and policy incentives that affect other energy sources (e.g., coal, nuclear, and renewables) and prudent development and operations of resources and infrastructure (e.g., management of hydraulic fracturing or methane emissions). For example, policies that accelerate coal plant retirements could result in significant increases in natural gas demand by the electric power sector. On the other hand, policies or congressional actions that maintain existing levels of coal-fired generation could result in reduced penetration of natural gas and reduced potential reductions of GHG and non-GHG emissions in the electric power sector. Similarly, requiring generation/sales quotas of renewable energy may also delay and reduce the penetration of natural gas.
- For some technologies, such as natural gas-based fuel cells, the potential for significant emissions reductions will be realized only with sustained and targeted RD&D programs. While continued RD&D also is needed to reduce the cost of CCS for natural gas-fired power plants, a key need here is also for sound policies for CCS deployment (see Text Box, "CCS Recommendations").

Evaluation of Policy Options and Frameworks

Employing the seven dimensions listed earlier, Table 4-8 summarizes the policies that could accelerate the deployment of the natural gas end-use technologies identified in the prior section. Within the suite of policies, there are many different factors to consider when choosing among different policies and

80 See Steven H. Levine, Frank C. Graves, and Metin Celebi, "Prospects for Natural Gas Under Climate Policy Legislation: Will There Be a Boom in Gas Demand?" The Brattle Group Discussion Paper, March 2010, page 6. See also Steve Fine and Joel Bluestein, ICF International, "GHG Regulatory Update and Economic Analysis," presented at INGAA Foundation Meeting, Miami, November 7, 2009.

Table 4-8. Examples of Policy Options and Frameworks for Accelerated Deployment of Natural Gas End-Use Technologies

Type of Policy	Possible Effects on Gas Consumption and Emissions	Case Study Illustrations*
Regulatory policies that affect gas and other energy sources		
A price on CO_2 emissions (cap & trade or carbon tax)	Would encourage shift from higher emission technologies (e.g., coal) to lower emissions for mature technologies in the near term	Redispatch away from high carbon plants; repower/refuel high carbon plants; build new gas plants; carbon capture & storage
Power plant greenhouse gas emission performance standards	Similar effects on fuel mix as a price on carbon	Redispatch away from high carbon plants; build new gas plants
Alternative interconnection standards	Could allow some gas-based technologies to compete with incumbent power supplies more effectively	Industrial combined heat and power (CHP); redispatch
Alternative clean energy mandates	Could allow some natural gas technologies to earn valuable credit as renewable or "clean energy" source	Redispatch/repower from high carbon plants; build new gas plants, industrial CHP; commercial CHP, carbon capture and sequestration (CCS)
Elimination of long-term subsidies or preferential policies for competing energy sources (renewable, nuclear, and coal)	Would level the playing field for all sources of energy	Redispatch/repower from high carbon plants; build new gas plants, industrial CHP; commercial CHP
Incentive policies that could be focused on gas-based technologies		
Financial incentives for gas-fired technologies, such as tax depreciation rules or limited assurances of market shares for early adopters	Could lower the cost of gas-fired technologies for some firms	Industrial CHP; fuel cells
Fast tracking of environmental permitting	Could make it easier to site and operate gas-fired technologies	Industrial CHP; natural gas appliances; redispatch; repower/refuel; CCS
Targeted research, development, demonstration, and deployment	Could lead to improved performance of gas-fired technologies, making them more competitive.	Industrial CHP; distributed fuel cells; carbon capture & storage; fuel cells; high-efficiency residential appliances
Loan guarantees, such as for infrastructure development or state/utility low-interest loans to consumers	Could make it easier and less costly to purchase natural gas technologies	Natural gas appliances, redispatch, CCS, repower/refuel
Other policies		
Positive incentives to encourage retirement of high-emitting or inefficient plants, such as payments for "stranded costs" in existing plants	Would reduce high-emitting or inefficient power supply and require more dispatch and possible new building of gas-fired plants	Redispatch away from high carbon plants; build new gas plants
Stricter regulation of existing and new coal plants	Would reduce coal-based power supply and require more dispatch and possible new building of gas-fired plants	Redispatch away from high carbon plants; build new gas plants; repower/refuel coal and oil plants
Ease siting of CO_2 pipelines and clarify assignment of long-term post-closure liability for stored CO_2	Would improve prospects for CCS, which could advantage both coal-based and gas-based CCS	Carbon capture & storage
Building performance standards	Could improve ability to install and operate on-site technologies, such as natural gas appliances	Natural gas appliances; fuel cells
Educational programs and labeling	Could improve awareness of emission-reducing opportunities	Natural gas appliances

* See Topic Papers under Carbon and Other Emissions in the End-Use Sectors for further illustration.

CCS Recommendations

The primary hurdles to implementation of carbon capture and sequestration (CCS) are the lack of a national policy for reducing GHG emissions; the high costs associated with constructing and operating CCS facilities, particularly the capture component; and lack of a clear and equitable policy on managing long-term responsibility for storage sites. The array of policy actions that could accelerate deployment of CCS technology include:

- Support for sub-scale and full-scale demonstration and deployment of commercially ready CCS technology on natural gas plants.
- Legal and regulatory frameworks for the design and operation of CCS including capture, transport, and storage. These frameworks would include accelerated right-of-way and environmental approval for CO_2 pipelines from the power plant to the storage site.
- Policies that provide for a clear transfer of long-term responsibility for closed storage sites, after appropriate site integrity verification, to a government/public entity for long-term management.

there are various trade-offs to pursuing some policies over others. Among these factors and tradeoffs are the following:

- **Timing.** Some policies offer the prospect for relatively near-term emissions reductions (i.e., over the next 5 to 10 years) while others may only make a substantial impact in the long-term (20 years or more). For example, policies like finalization of EPA regulations, and methane reductions along the natural gas fuel cycle, offer opportunities for near-term reductions. Other potential policies, such as requiring CCS on new gas-fired power plants, will not result in significant emission reductions for a few decades (when substantial deployment is achieved). To achieve long-term goals most effectively, CCS RD&D policies and policies surrounding residential/commercial appliances may need to be initiated in the near term.
- **Cost.** Choosing policy options that cause substantial investment today in current technologies might risk abandoning other promising technology options that could be an important component of an overall policy designed to maximize emission reductions over the long run.
- **Environmental Impact.** Policies that offer the largest long-term emissions reductions potential may also require the highest-cost alternative or an alternative that does not result in near-term emission reductions. Such trade-offs need to be carefully weighed.

Clearly, there are other factors that could be important in the development of policies other than those listed (such as economic impact, job creation, etc.). Moreover, there is interplay between these different factors with some policies favorable to one factor but unfavorable to another. Some policies might serve to promote only a single technology while others may promote multiple technologies.

Recommendations

Because of well-known and documented market barriers, the main recommendation is that if the United States wants to adopt an energy and environmental strategy that promotes economic, energy, and environmental security, it must work simultaneously and strategically on multiple policy fronts. That is, policymakers – when balancing energy, environment, and economic security – should consider the trade-offs between near-term opportunities (e.g., finalization of non-GHG EPA regulations) and long-term requirements (e.g., if large reductions in GHG emissions are required). Thus, policymakers should take a "phased-in" approach while recognizing the complexities of the energy industry related to infrastructure turnover, reliability, and sound environmental policies. The following policies should be pursued or considered as part of this portfolio approach to balance the environmental and energy goals of the study.[81]

- **Provide regulatory certainty to the power sector by finalizing the non-GHG EPA regulations applicable to the power sector.**[82] Today, the uncer-

81 See the "Study Request" section in the Preface and the Executive Summary of this report.

82 EPA regulations include rules identified in the "Impact of Non-GHG EPA Rules on the Power Sector" section of this chapter. The NPC does not take a position on scope and content of these EPA rules impacting the power sector other than the findings in that section.

tainty associated with the pending EPA regulations may prevent electric generating companies from making decisions regarding whether and when to retire aging coal-fired power plants. Policymakers should take into account the benefits for market conditions from the finalization of EPA regulations affecting the power sector, especially those regulations not related to controlling GHG emissions. These benefits include reduced uncertainty in the market and provision of near-term investment signals, as well as the reduction of emissions of sulfur dioxide, nitrogen oxide, mercury, and particulates, along with collateral reductions of GHG emissions from power generation. As discussed earlier, many of these plants are older plants that may be reaching the end of their useful life, some in excess of 50 years in age. A review of existing research suggests that roughly 58 GW of aging coal plant capacity might be retired due to potential EPA regulations. Much of the capacity associated with these retirements would be replaced by natural gas-fired generation and result in significant increases in natural gas demand and reductions in CO_2 and other emissions.

While there may be significant issues that need to be resolved that are beyond the scope of this chapter (e.g., reliability, specific control requirements, human resources, and infrastructure needs), power plant operators need regulatory clarity and certainty with respect to the type of required emissions controls and other environmental regulations. Resolution of the EPA rules, as well as compliance timelines and decisions affecting individual plants, must take into consideration reliability impacts, recognizing that there are a variety of tools available to address location-specific reliability issues. The FERC, NERC, EPA, DOE, and individual PUCs and ISOs must carefully analyze these important issues and develop a comprehensive plan to address these issues.

Improved building codes/standards, appliance codes/standards, tax credits, and education programs to encourage more efficient energy use, which can include deployment/installation of new residential natural gas appliances, should be implemented through a joint government (federal/state/local) and industry (distribution and other companies) partnership. Specific barriers (e.g., social, contractual, zoning) in the residential and commercial sector must be overcome. Since new residential natural gas appliances offer such a significant emissions reduction potential over the long-term, a variety of policies must be pursued to achieve this potential. (See Text Box, "New Residential Appliances and Equipment," for additional recommendations.)

- **Consider an appropriate carbon policy for internalizing the cost of carbon impacts into fuel prices.** In his letter asking the NPC to conduct this study, the Secretary of Energy asked the NPC to examine the contribution that natural gas could make in a transition to a lower carbon fuel mix. He did not ask the NPC to weigh in on the merits of adopting a climate policy.[83] The NPC recognizes that the United States, with its market-based economy,

83 The merits of a particular carbon policy are beyond the scope of the study and the NPC does not endorse a particular carbon policy. The study also did not review macroeconomic, international competitiveness, health or environmental benefits, or global energy security of a carbon policy.

New Residential Appliances and Equipment

The primary barriers to deployment of new residential gas appliances with efficiencies of over 90% are technology development, first cost, split incentives (owner vs. renter), and lack of gas mains (in some sections of the country). Policies that could accelerate new gas appliances include:

- More aggressive federal energy efficiency standards for appliances based on full fuel cycle analysis, continued DOE support for model building energy code development, and enhanced DOE support (such as for training and technical assistance) for state and local adoption and enforcement of such codes.
- State and local education programs to help consumers make more educated choices.
- Tax credits for installing higher-efficiency, lower-CO_2 emitting equipment.
- Technology RD&D to help lower the cost of higher-efficiency natural gas equipment for the home, including condensing water heaters, instantaneous water heaters, and gas heat pumps.

will find it difficult if not impossible to substantially further decrease its carbon emissions without introducing higher costs or regulatory controls associated with GHG emissions from development, delivery, or combustion of fossil fuels. Absent a price on carbon, energy efficiency, and those power sources with lower carbon intensity – such as renewables, nuclear, and natural gas – will tend to be undervalued as individuals, businesses, and governments make decisions. A price on carbon, implied or explicit, or similar regulatory action that prices the environmental costs of fossil fuel emissions, will help to accelerate shifts to lower carbon-intensity sources of electric power.

As policymakers consider energy and environmental policies, they should consider a carbon policy that recognizes the abundant natural gas resource base while ensuring the carbon price signal is not distorted to favor one energy source (i.e., without subsidies or preferential programs or policies). Such a policy could take the form of an explicit carbon price through market-based policies such as a carbon tax or other market mechanism that allows for trading of carbon emission permits.

Designed appropriately, a GHG policy could reduce GHG emissions, provide the economic incentive for increased natural gas use as well as for the development of other low- to zero-emitting technologies including renewables, nuclear, coal with CCS, and natural gas with CCS.

Decision makers could also consider other policies with an implied price on carbon, such as a performance standard, a clean energy standard, or coal plant retirement incentives. For example, if the United States proceeds with a Clean Energy Standard (CES),[84] then such a CES policy should evaluate the inclusion of natural gas as a "qualified clean energy" source for both new and existing natural gas power plants. Preliminary research indicates that inclusion of natural gas for existing and new natural gas plants may have a significant effect on cumulative CO_2 emissions relative to scenarios that do not include emissions-based market mechanisms.[85]

- **Consider long-term strategies for prudent development in the development of existing and new natural gas capacity. These actions should include:**
  - **A robust industry-government partnership to promote technologies, protocols, and practices to measure, estimate, and manage (reduce) natural gas emissions – in all cycles of production and delivery.** A significant amount of the emissions in the natural gas value chain occurs to facilitate safe and reliable operations (e.g., operations of actuators and relief valves). However, regardless of the uncertainty with the emissions estimates and measurements, continuing to adopt and employ EPA Gas STAR technologies or equivalent technologies will reduce methane emissions along the natural gas system while maintaining high safety and reliability standards. Barriers to adoption of these technologies should be fully evaluated and the industry and government must work together to overcome these barriers.
  - **Research, development, and demonstration of CCS for gas-fired power plants.** The development of CCS for gas-fired power plants is important in that a significant amount of natural gas-fired combined cycle capacity is expected to be built in the next two decades. If deep GHG emissions reductions are ultimately required (e.g., 80% by 2050), CCS or other lower emitting technologies are vital to meet the emissions goals. A coherent long-term vision, dedicated focus, and adequate funding must be made by all stakeholders now to implement the required RD&D and deploy commercially ready technologies to meet longer-term, deeper reduction targets. (For additional recommendations, see Text Box entitled "CCS Recommendations" earlier in this chapter.)

84 Clean Energy Standard is a market-based policy approach that mandates a certain percentage of electricity generation from "clean energy" sources beyond non-hydro renewables.

85 Karen Palmer, Richard Sweeney, and Maura Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity," Resources for the Future. June 2010; revised October 2010.