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Role of Alternative Energy Sources: Natural Gas Technology Assessment

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
AGR	Acid gas removal
ANL	Argonne National Laboratory
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AVB	Aluminum vertical break
Bcf	Billion cubic feet
Btu	British thermal unit
CBM	Coal bed methane
CCS	Carbon capture and sequestration
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COE	Cost of electricity
CTG	Combustion turbines/generators
DOE	Department of Energy
ECF	Energy conversion facility
eGRID	Emissions and generation resource integrated database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EROI	Energy return on investment
EUR	Estimated ultimate recovery
EXPC	Existing pulverized coal
EV	Expected Value
G&A	General and administrative
GHG	Greenhouse gas
GJ	Gigajoule
GTSC	Gas turbine simple cycle
GWP	Global warming potential
H_2S	Hydrogen sulfide
Hg	Mercury
HHV	Higher heating value
HRSG	Heat recovery steam generator
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
ISO	International Standards Organization
kJ	Kilojoule
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
LC	Life cycle
LCA	Life cycle analysis
LCC	Life cycle cost
LCOE	Levelized cost of electricity
LHV	Lower heating value
LNG	Liquefied natural gas
MACRS	Modified accelerated cost recovery system
Mcf	Thousand cubic feet
MCL	Maximum containment level
MJ	Megajoule
MMBtu	Million Btu
MMcf	Million cubic feet
MW,MWe	Megawatt electric
MWh	Megawatt-hour
N_2	Nitrogen
N_2O	Nitrous oxide
N/A	Not applicable
NO_X	Nitrogen oxides
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NH_3	Ammonia
NMVOC	Non-methane volatile organic compound
NYSDEC	New York State Department of Environmental Quality
O&M	Operating and maintenance
Pb	Lead
PM	Particulate matter
PT	Product transport
psig	Pounds per square inch, gauge
RFS2	Renewable Fuel Standard, Version 2
RMA	Raw material acquisition
RMT	Raw material transport
scf	Standard cubic feet
SCPC	Supercritical pulverized coal
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
T&D	Transmission and distribution
Tcf	Trillion cubic feet
TDS	Total dissolved solids
TOC	Total overnight costs
ton	Short ton
TPC	Total plant cost
USDA	U.S. Department of Agriculture
VOC	Volatile organic compound
WWTP	Wastewater treatment plant

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Executive Summary

This study discusses the role of natural gas power in meeting the energy needs of the United States (U.S.). This includes the identification of key issues related to natural gas and, where applicable, analyses of environmental and cost aspects of natural gas power.

The performance of natural gas power plants is detailed in the National Energy Technology Laboratory's (NETL) bituminous baseline (NETL, 2010a), which includes cases for natural gas combined cycle (NGCC) technologies. The NGCC power plant in NETL's bituminous baseline is a 555-megawatt (MWe) (net power output) thermoelectric generation facility. It is possible to configure this technology with a carbon recovery system that captures 90 percent of the CO_2 in the flue gas, with the trade-off being a 14.6 percent reduction in net power (474 MW vs. 555 MW). A gas turbine simple cycle (GTSC) plant is also considered in this study. The performance of the GTSC plant was adapted from the NETL baseline of NGCC power by considering only the streams that enter and exit the combustion turbines/generators and not accounting for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW. This analysis also considers the characteristics of an average baseload natural gas plant, which is based on efficiency data from the Emissions and Generation Resource Integrated Database (eGRID) (EPA, 2010). The average efficiency of baseload natural gas power plants is 36.2 percent. When larger, more productive plants are sampled, the average efficiency is 47.1 percent.

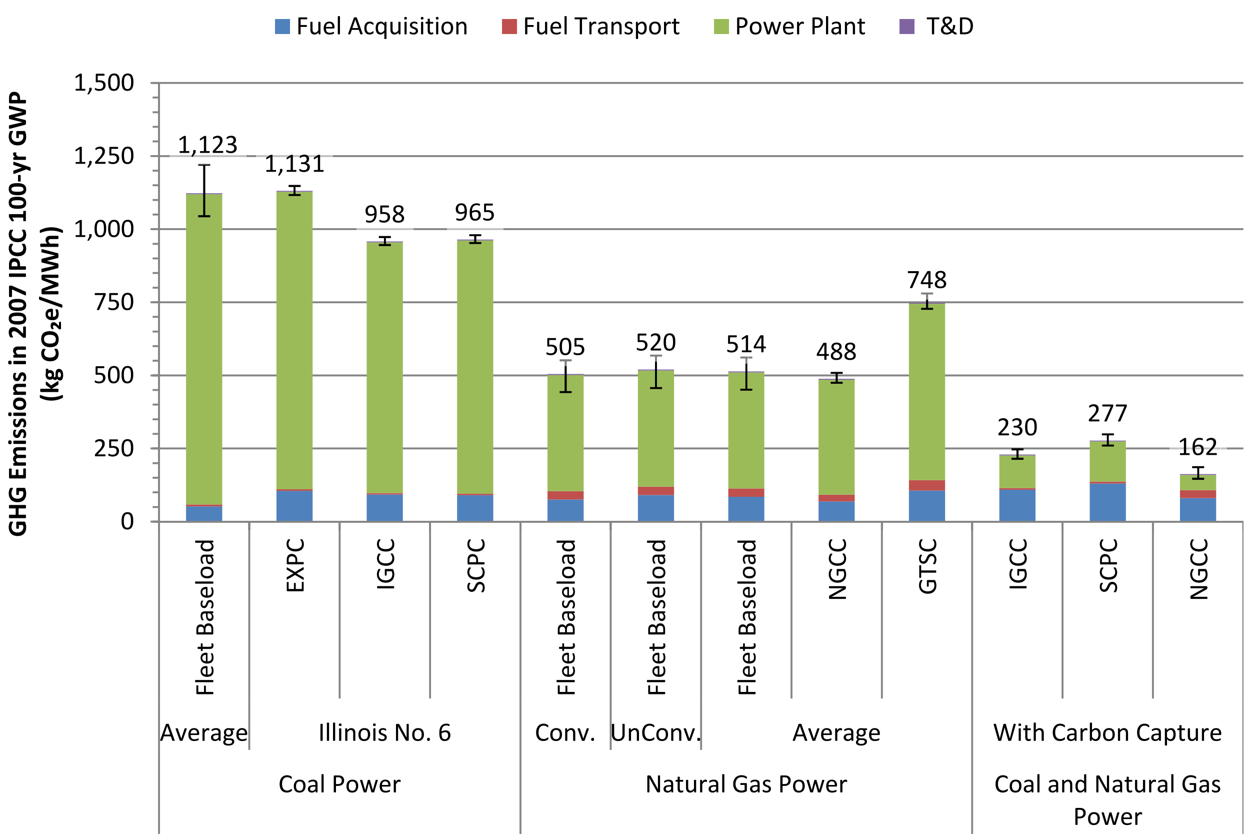
In addition to understanding the efficiency and other performance characteristics of natural gas power plants, it is also important to understand the availability, environmental, cost, and other issues surrounding natural gas.

The U.S. supply of natural gas consists of domestic and imported sources and includes conventional and unconventional technologies. The total U.S. demand for natural gas was 24.1 trillion cubic feet (Tcf) in 2010 and is projected to grow to 26.5 Tcf by 2035 EIA (EIA, 2012a). This demand is balanced by conventional and unconventional supply sources, including an increasing share of shale gas. Between 2009 and 2010, shale gas grew from 14 percent to 24 percent of the U.S. natural gas supply and, based on AEO's reference case (EIA, 2012a), is projected to comprise 49 percent of the supply by 2035. The Marcellus Shale formation is the latest location that has been developed for natural gas extraction. In 2008, the Marcellus Shale was estimated to contain 50 Tcf of technically recoverable natural gas. This estimate was based on the known area and thickness of Marcellus Shale factored by production rates observed for Barnett Shale (Engelder, 2009; Soeder & Kappel, 2009). In 2011, the U.S. Geological Survey (USGS) used the latest geologic information and engineering data to estimate 84 Tcf of technically recoverable gas from the Marcellus Shale (Pierce, Colman, & Demas, 2011). Terry Engelder, a leading authority on Marcellus Shale and professor of geosciences at Pennsylvania State University, has a significantly higher estimate of 489 Tcf of technically recoverable natural gas from Marcellus Shale (Engelder, 2009).

Given the increase in shale gas production in the U.S., domestic natural gas prices are projected to remain low over the next few years due to supply growth that exceeds demand growth (EIA, 2012b). The relatively high levels of underground natural gas storage will also contribute to excess supply in the short term. As of April 2012, levels of U.S. natural gas in storage were relatively high, at 2.5 trillion cubic feet (Tcf). This storage volume is 51 percent higher than storage levels in April 2011. (EIA, 2012d)

A life cycle analysis (LCA) was conducted to evaluate the environmental characteristics of natural gas power. The LCA accounted for significant energy and material flows, beginning with the extraction of natural gas and ending with electricity delivered to the consumer. The key metrics of the LCA include greenhouse gas (GHG) emissions, other emissions to air, water withdrawal and discharge, water quality, and land use change. The GHG emissions from natural gas power are also compared to the GHG emissions from coal power. While different types of natural gas (i.e., conventional and unconventional) have different environmental profiles, the GHG profile of the natural gas life cycle (LC) is driven by the CO_2 emissions from the power plant. **Figure ES-1** shows the LC GHG emissions of natural gas and coal technologies per MWh of electricity delivered to the consumer. The GHG emissions are expressed in terms of global warming potentials (GWP) based on CO_2 equivalency factors developed by the Intergovernmental Panel on Climate Change (IPCC) in 2007.

Figure ES-1: Life Cycle GHG Emissions from Natural Gas and Coal Power



An understanding of the overall natural gas market provides more information on the price of natural gas than a focus on the costs of specific extraction technologies. The price volatility of natural gas is a barrier to the use of natural gas for baseload power generation and hinders capital investments in new natural gas energy systems. Within the past decade, the spot price of U.S. natural gas has ranged between $1 and $14 per MMBtu ($0.94 to $13 per GJ).

Regardless of natural gas price volatility, some utilities have decided to take advantage of low natural gas prices by investing in new natural gas power plants. A recent press release from Dominion Virginia Power publicizes their intent to build a new 1,300 MW combined cycle natural gas power plant, in Brunswick County, Virginia (DVP, 2012). Duke Energy has added natural gas power capacity in North Carolina, including a 620 MW combined cycle plant that began operating in 2011, and a similar plant that will begin operating in 2012 (Rogers, 2012). The EIA projects that the consumption of natural gas in the power sector will grow by 16 percent in 2012 (EIA, 2012c).

The costs of three natural gas scenarios were modeled: NGCC, NGCC with carbon capture and sequestration (CCS), and GTSC. The NGCC case without CCS has the lowest COE ($53.36/MWh), and the NGCC case with CCS has the highest COE ($81.37/MWh). The COE of the GTSC system is $71.76/MWh. NGCC power has higher capital costs than GTSC power, but NGCC power is more efficient so it has lower fuel costs than GTSC power.

Barriers include technical issues that could prevent or delay the implementation of a technology. The limited capacity of the existing natural gas pipeline network could also be a barrier to the immediate growth of shale gas production in the Northeast. According to a representative of El Paso Pipeline Partners (Langston, 2011), the installation of new compressor stations along the pipeline network or the installation of new pipelines alongside existing pipelines are feasible solutions to this issue (Langston, 2011).

Legislative actions are a risk to the implementation of natural gas systems. For example, in December 2010, Governor Paterson vetoed legislation that would have placed a six-month moratorium on hydrofracking in New York. Governor Paterson followed his veto with an executive order that prohibited horizontal drilling for six months (through July 2011), but still allowed hydrofracking of vertical wells (NYSDEC, 2010). In June 2011, Governor Cuomo, Paterson's successor, recommended lifting the horizontal drilling ban (Hakim & Confessore, 2011), and the New York State Department of Environmental Conservation released new recommendations that favored high-volume fracking on privately-owned land as long as it is not near aquifers (NYSDEC, 2011). These new recommendations were faced with opposition. For example, in February 2012 the New York State Supreme Court ruled that municipalities can use zoning laws to prohibit oil and natural gas drilling (Navarro, 2012).

Pennsylvania has also faced legislative uncertainty with respect to natural gas extraction. In June 2011, the Pennsylvania House of Representatives canceled a vote on an impact fee on gas extracted from the Marcellus Shale (Scolforo, 2011). After months of controversy, in February 2012, Pennsylvania approved legislation that taxes the shale gas industry and sets standards for developing gas wells. Proponents of the legislation see it as a way for state and local governments to take advantage of a valuable revenue stream. Critics argue that the new laws do not adequately address the environmental and safety issues of shale gas extraction. (Tavernise, 2012)

Expert opinions include the outlook of natural gas industry players and experts, most of which are currently expressing positive forecasts for future natural gas resource availability.

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1 Introduction

This study evaluates the role of natural gas in the energy supply of the United States (U.S.) by focusing on the resource base, growth, environmental characteristics, costs, barriers, risks of implementation, and expert opinions surrounding natural gas used in power generation. The criteria used by the National Energy Technology Laboratory (NETL) to evaluate the roles of energy sources are summarized in **Table 1-1**.

Table 1-1: Criteria for Evaluating Roles of Energy Sources

Criteria	Description
Resource Base	Availability and accessibility of natural resources for the production of energy feedstocks
Growth	Current market direction of the energy system – this could mean emerging, mature, increasing, or declining growth scenarios
Environmental Profile	Life cycle (LC) resource consumption (including raw material and water), emissions to air and water, solid waste burdens, and land use
Cost Profile	Capital costs of new infrastructure and equipment, operating and maintenance (O&M) costs, and cost of electricity (COE)
Barriers	Technical barriers that could prevent the successful implementation of a technology
Risks of Implementation	Non-technical barriers such as financial, environmental, regulatory, and/or public perception concerns that are obstacles to implementation
Expert Opinion	Opinions of stakeholders in industry, academia, and government

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, industrial, and transportation applications in addition to an expanding role in power production. Domestic sources of natural gas include onshore and offshore conventional wells with a wide range of production rates. Other domestic sources of natural gas include unconventional wells that use technologies that stimulate the reservoir to enhance natural gas recovery. For example, hydraulic fracturing technologies inject a mixture of water and other reagents into shale and other tight geological formations in order to free trapped natural gas, and coal bed methane (CBM) wells are stimulated by removing naturally occurring water from the formation.

After natural gas is extracted, a series of dehydration and acid removal processes are necessary to remove contaminants and prepare it for pipeline transport. The current U.S. natural gas pipeline network connects suppliers in the South with markets in the Midwest and Northeast, and also has pipelines that traverse the Southwest and reach the west coast. This existing pipeline network can be adapted to serve growing natural gas extraction sources, such as new shale gas wells in the Northeast. Due to the efficacy of natural gas processing and the interconnected U.S. natural gas pipeline network, natural gas is a commodity with quality characteristics that do not vary significantly between markets.

There are many applications for natural gas in the utility, industrial, transportation, and residential sectors. This analysis focuses on the role of natural gas in power generation. Simple cycle systems use gas turbines that compress inlet air with a mixture of natural gas that is combusted to produce a high pressure stream that drives a turbine and produces power. Combined cycle systems also use gas turbines, but recover heat to generate steam and drive a separate steam cycle for power generation.

2 Natural Gas Power Technology Performance

This study evaluates the following natural gas power technologies:

- Natural Gas Combined Cycle (NGCC)
- Natural Gas Combined Cycle with Carbon Capture and Sequestration (NGCC/ccs)
- Gas Turbine Simple Cycle (GTSC)
- U.S. Fleet Baseload Average (Fleet Baseload)

The performance of natural gas power plants is detailed in NETL's bituminous baseline (NETL, 2010a), which includes cases for natural gas combined cycle (NGCC) technologies. The NGCC power plant in NETL's bituminous baseline is a 555-megawatt (MWe) (net power output) thermoelectric generation facility that uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators (CTG). Each CTG is followed by a heat recovery steam generator (HRSG), and all net steam produced in the two HRSGs flows to a single steam turbine. It is possible to configure this technology with a carbon recovery system; in this study, the Fluor Econamine℠ technology is modeled. The carbon capture system uses system steam for solvent regeneration and also consumes power for pumps and other auxiliary equipment. When carbon capture is employed, the net power output of the NGCC plant is 474 MW. The carbon capture system captures 90 percent of the CO_2 in the flue gas, with the trade-off being a 14.6 percent reduction in net power (474 MW vs. 555 MW). When comparing the higher heating value (HHV) of the natural gas input to the energy of the saleable electricity, the NGCC plant has efficiencies of 50.2 percent and 42.8 percent for the base case and carbon capture case, respectively. Both NGCC systems have an 85 percent capacity factor.

A gas turbine simple cycle (GTSC) plant is also considered in this study. The GTSC plant uses two parallel, advanced F-Class natural gas-fired CTG. The performance of the GTSC plant was adapted from NETL's baseline of NGCC power by considering only the streams that enter and exit the CTG and not accounting for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW and it has an 85 percent capacity factor.

This analysis also considers the characteristics of an average baseload natural gas plant, which is based on efficiency data from eGRID (EPA, 2010). The average heat rate was calculated for plants with a capacity factor over 60 percent to represent those plants performing a baseload role. Another average, weighted by production (so the efficiency of larger, more productive plants had more weight), was calculated as 47.1 percent. This efficiency is used to generate results for average natural gas power in the U.S. An energy content between 990 and 1,030 Btu/scf and a carbon content of natural gas between 72 percent and 80 percent by mass were used to create the feed rate of natural gas and emissions from combustion.

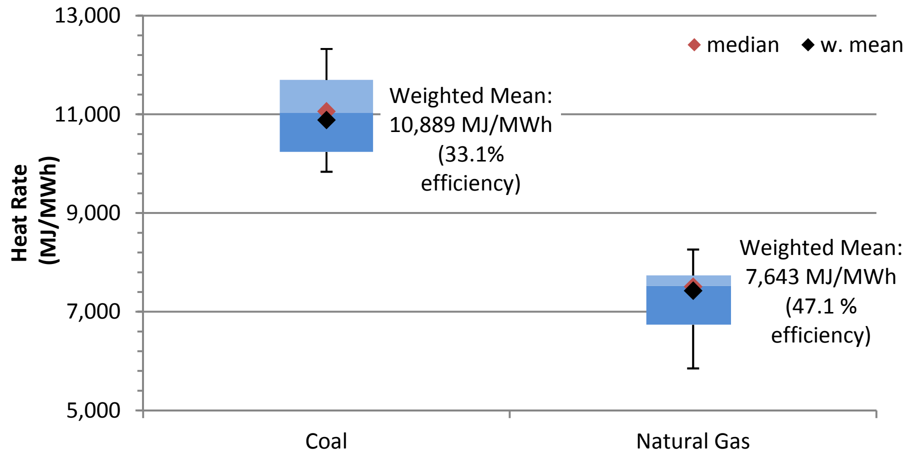
The performance characteristics of natural gas power plants are shown in **Table 2-1**. For the two NGCC technologies, all data are based on NETL's bituminous baseline (NETL, 2010a), except for the emission of methane, nitrous oxide, and sulfur dioxide, which are a function of the natural gas consumption rate of an auxiliary boiler and the Environmental Protection Agency's (EPA) emission factors for natural gas combustion (EPA, 1995).

Table 2-1: Performance Characteristics of Natural Gas Power Plants

Characteristic	NGCC	NGCC/ccs	GTSC	Fleet Baseload
Power Summary (kW)				
Gas Turbine Power	362,200	362,200	362,200	N/A
Steam Turbine Power	202,500	148,800	0	N/A
Total Power	**564,700**	**511,000**	**362,200**	**N/A**
Auxiliary Load Summary (kW)				
Condensate Pumps	170	80	0	N/A
Boiler Feedwater Pumps	2,720	2,710	0	N/A
Amine System Auxiliaries	0	9,600	0	N/A
CO_2 Compression	0	15,200	0	N/A
Circulating Water Pump	2,300	4,360	0	N/A
Ground Water Pumps	210	360	0	N/A
Cooling Tower Fans	1,190	2,250	0	N/A
Selective Catalytic Reduction	10	10	10	N/A
Gas Turbine Auxiliaries	700	700	700	N/A
Steam Turbine Auxiliaries	100	100	0	N/A
Miscellaneous Balance of Plant	500	500	500	N/A
Transformer Losses	1,720	1,560	1,106	N/A
Total Auxiliary Load	**9,620**	**37,430**	**2,316**	N/A
Net Power, Efficiency, and Heat Rate				
Net Power, kW	555,080	473,570	359,884	N/A
Net Plant Efficiency (HHV)	50.20%	42.80%	30.04%	47.10%
Net Plant Efficiency (LHV)	55.70%	47.50%	33.32%	N/A
Net Plant Heat Rate (HHV), kJ/kWh	7,172	8,406	11,983	7,647
Net Plant Heat Rate (LHV), kJ/kWh	6,466	7,579	10,804	N/A
Consumables				
Natural Gas Feed Flow, kg/hr	75,901	75,901	75,901	N/A
Thermal Input (HHV), kW_{th}	1,105,812	1,105,812	1,105,812	N/A
Thermal Input (LHV) , kW_{th}	997,032	997,032	997.032	N/A
Raw Water Withdrawal, m^3/min	8.9	15.1	0	N/A
Raw Water Consumption, m^3/min	6.9	11.3	0	N/A
Air Emissions (kg/kWh)				
Carbon Dioxide	0.362	0.0463	0.560	0.379
Methane	7.40E-09	8.61E-09	N/A	N/A
Nitrous Oxide	2.06E-09	2.39E-09	N/A	N/A
Carbon Monoxide	2.70E-07	3.14E-07	4.59E-04	N/A
Nitrogen Oxides	2.80E-05	3.25E-05	4.24E-05	N/A
Sulfur Dioxide	1.93E-09	2.24E-09	N/A	N/A

For the U.S. fleet average power plants, **Figure 2-1** shows the distribution of heat rates and associated efficiencies from eGRID. For comparison, the heat rates of coal-fired power plants are also shown. To arrive at the samples shown below, plants smaller than 200 MW, with capacity factors lower than 60 percent and with primary feedstock percentages below 85 percent were cut. The boxes are the first and third quartiles, and the whiskers the 5th and 95th percentiles. The division in the boxes is the median value. The black diamond is the production-weighted mean, and the orange diamond is the median.

Figure 2-1: Fleet Baseload Heat Rates for Coal and Natural Gas



The types of technologies employed by natural gas power plants are important factors in the overall plant efficiency and emissions. However, the activities that occur upstream and downstream of natural gas power plants also incur environmental burdens, making life cycle assessment (LCA) a necessary framework for understanding of the environmental burdens of the entire natural gas supply chain. In addition to environmental concerns, the role of natural gas in the U.S. energy portfolio is also affected by costs, resource availability, barriers, and other issues.

3 Resource Base and Potential for Growth

The resource base describes the availability of a natural resource. U.S. producers have successfully developed conventional sources of natural gas at onshore and offshore sites, and have also developed unconventional sources in tight gas reserves, such as coal beds and shale formations. The Marcellus Shale gas formation is the latest location that has been developed for natural gas extraction.

3.1 Natural Gas Demand

Natural gas is a key component of national energy consumption, so an understanding of total energy demand provides information on natural gas demand. The 2008 downturn in the U.S. economy resulted in a 4.7 percent drop in energy consumption in 2009. U.S. energy consumption grew by 3.7 percent between 2009 and 2010, but is expected to be flat in the near term and grow slowly in the long term. The AEO 2012 reference case projects an average annual growth of 0.4 percent through 2035 (EIA, 2012a).

Natural gas prices have been volatile over the last decade, including price peaks as high $13.4/MMBtu in October 2005 and $12.7/MMBtu in June 2008. The 2008 price peak was followed by a steady decline to $3.0/MMBtu in September 2009, a small recovery in 2010, and then another decline to current levels of approximately $2/MMBtu. U.S. natural gas prices are projected to increase in the long term; however, the forecast made by the AEO 2012 reference case suggests that natural gas prices will not recover to 2008 price levels (greater than $6 per MMBtu in 2008 dollars) until 2030 (EIA, 2012a).

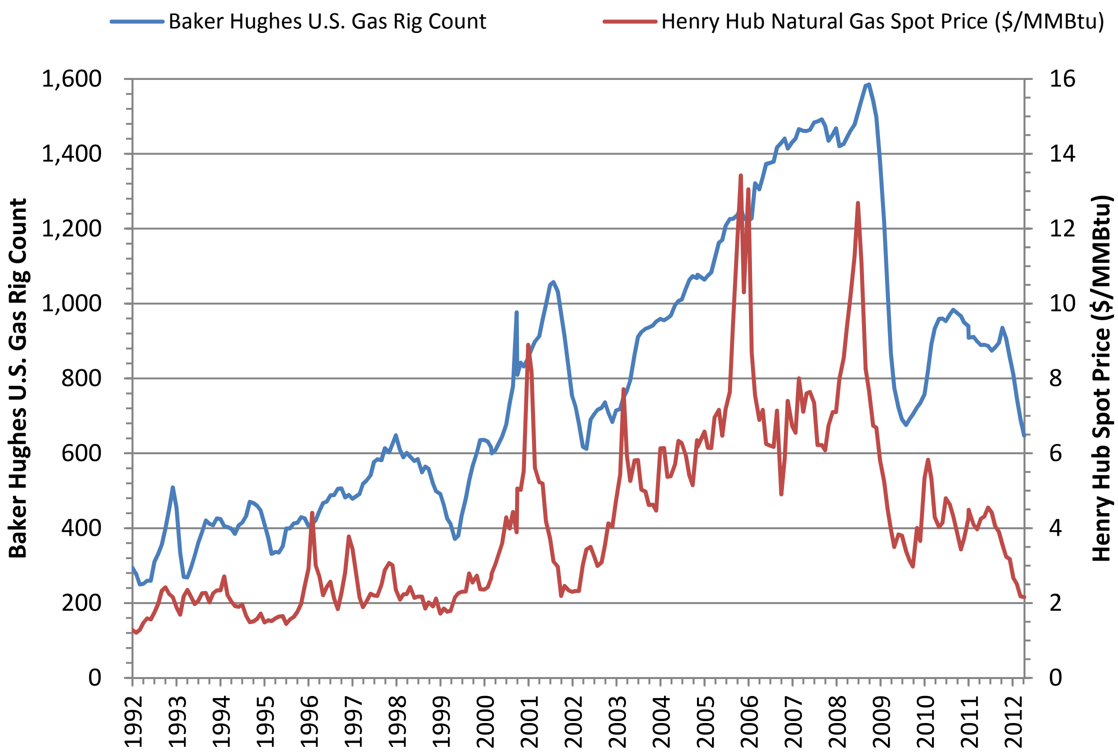
Changes in energy demand, weather variations, and supply disruptions contribute to volatility in natural gas prices. As the economy recovers, the industrial and utility sectors will be key leaders of increased natural gas consumption. The industrial sector is a major consumer of natural gas, accounting for 27 percent of domestic natural gas consumption in 2010 (EIA, 2012a). The electric power sector, which accounted for 31 percent of domestic natural gas consumption in 2010, is also expected to increase consumption of natural gas (EIA, 2012a). Mild temperatures could increase the amount of underground-stored natural gas, while extreme temperatures or unexpected supply disruptions could decrease the storage levels significantly due to accelerated demand or reduced supply.

Regardless of natural gas price volatility, some utilities have decided to take advantage of low natural gas prices by investing in new natural gas power plants. A recent press release from Dominion Virginia Power publicizes their intent to build a new 1,300 MW combined cycle natural gas power plant in Brunswick County, Virginia (DVP, 2012). Duke Energy has added natural gas power capacity in North Carolina, including a 620 MW combined cycle plant that began operating in 2011, and a similar plant that will begin operating in 2012 (Rogers, 2012). The EIA projects that the consumption of natural gas in the power sector will grow by 16 percent in 2012 (EIA, 2012c).

3.2 Natural Gas Supply

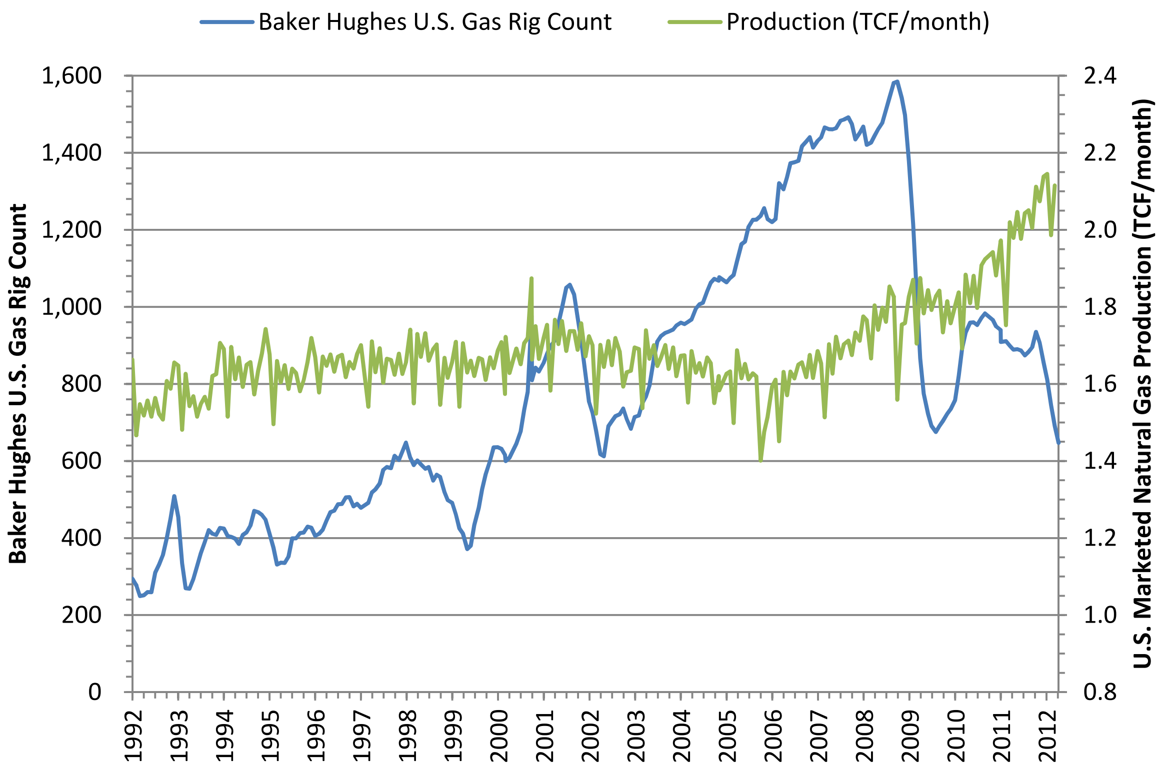
Total U.S. natural gas production increased by 1.4 percent from 2008 to 2009. During the same period, there was a 44 percent drop in the U.S. gas rig count and a 54 percent drop in U.S. natural gas prices (Baker-Hughes, 2012; EIA, 2012a). Natural gas prices stayed low in 2010, but U.S. dry gas production climbed 4.9 percent and the Baker Hughes U.S. natural gas rig counts rose 22 percent (Baker-Hughes, 2012). The increase in rig count and gas production during a period of low gas prices indicated an adherence to lease and drilling contracts, and reduced finding and development costs for certain “sweet spot” shale gas plays. The high production rates and declining natural gas prices are due in part to the improved recovery rates of natural gas, which have been made possible by new technologies, specifically horizontal drilling, seismic testing, and hydrofracking.

Figure 3-1: Natural Gas Spot Price vs. U.S. Gas Rig Count (Baker-Hughes, 2012; EIA, 2012a)



As shown in **Figure 3-2**, historical data for rig count and natural gas production demonstrate that, in general, natural gas producers have invested in new well development in response to increased demand for natural gas. The steep decline in rig count in 2008 indicates that the development of new wells was too aggressive between 2006 and 2007. The data for 2010 through 2012 show rises, plateaus, and declines in rig count, so more data is necessary to determine if producers have changed their well development strategies. To manage the risk of market volatility, it is possible that natural gas producers are attempting to establish a more tempered approach to well development.

Figure 3-2: Natural Gas Production vs. U.S. Gas Rig Count (Baker-Hughes, 2012; EIA, 2012a)



Given the increase in shale gas production in the U.S., domestic natural gas prices are projected to remain low over the next few years due to a supply growth that exceeds demand growth (EIA, 2012b). Between 2009 and 2010 alone, U.S. shale gas production grew from 2.9 to 5.0 trillion cubic feet (TCF), representing an increase from 16 percent to 24 percent of U.S. domestic supply of natural gas. However, U.S. natural gas companies seem to be trimming their higher cost production until prices reach higher ground, and many uncompleted wells appear to be waiting as well. As a result, the direction of U.S. natural gas prices is uncertain. Further, projected gains in U.S. natural gas prices could be undermined if domestic companies set aggressive gas production targets, if U.S. natural gas in underground storage is not drawn down by increased consumption from improved economic growth.

The production of natural gas from shale formations is projected to grow (as discussed in the next section and illustrated in **Figure 3-3**), but production from other natural gas sources will show slower growth rates or overall declines. For example, EIA forecasts that the production of offshore natural gas in the Gulf of Mexico will decline 8.8 percent between 2012 and 2013, followed by gradual growth to production levels comparable to pre-2008 offshore production levels. The production of conventional onshore natural gas is expected to decline by 5.5 percent between 2012 and 2013 and exhibit an overall decline in the long term (EIA, 2012a).

Given the increase in shale gas production in the U.S., domestic natural gas prices are projected to remain low over the next few years (EIA, 2012a). The relatively high levels of underground natural gas storage will also contribute to excess supply in the short term and will result in low natural gas prices. As of April 2012, levels of U.S. natural gas in storage were relatively high, at 2.5 trillion cubic feet (Tcf). This storage volume is 51 percent higher than storage levels in April 2011. (EIA, 2012d)

Pipeline imports to the U.S. decreased by 2.2 percent between 2009 and 2010, and are projected to have larger decreases in the next two years (EIA, 2012a). These decreases are likely a result of reduced U.S. natural gas prices and increased Canadian consumption. Similar decreases are expected for imports of LNG (liquefied petroleum gas) (EIA, 2012a). Solid domestic production, high inventories, and relatively low U.S. natural gas prices are expected to discourage liquefied natural gas (LNG) imports.

3.3 Shale Gas and Future Supplies

The Marcellus Shale is a geological formation that traverses Ohio, West Virginia, Pennsylvania, and New York. New horizontal drilling technology and hydraulic fracturing (“hydrofracking”) allow the recovery of natural gas from Marcellus Shale, which could provide 20 years of natural gas supply to the U.S. (Engelder, 2009).

In 2008, the Marcellus Shale was estimated to contain 50 Tcf of recoverable natural gas. This estimate was based on the known area and thickness of Marcellus Shale factored by production rates observed for Barnett Shale (Engelder, 2009; Soeder & Kappel, 2009). Recent data indicates that the Marcellus Shale includes a significantly higher amount of recoverable natural gas than estimated in 2008. In 2011, the U.S. Geological Survey (USGS) used the latest geologic information and engineering data to estimate 84 Tcf of technically recoverable gas from the Marcellus Shale (Pierce, et al., 2011). Terry Engelder, a leading authority on Marcellus Shale and professor of geosciences at Pennsylvania State University, estimates that 489 Tcf of natural gas can be recovered from the Marcellus Shale (Engelder, 2009).

Engelder’s estimate of the total recoverable natural gas contained in the Marcellus Shale is based on production data for 50 wells operating in the Marcellus Shale region. The estimate also assumes that the 50-year performance of these wells follows a steeply declining performance curve (described by a power-law rate decline) and that 70 percent of the land in the Marcellus region will be developed for natural gas recovery. Engelder’s estimate ranges from 221 Tcf (a 90 percent probability) to 867 Tcf (a 10 percent probability); the recovery of 489 Tcf is 50 percent probable (Engelder, 2009).

The above estimates of the natural gas resource base of Marcellus Shale are technically recoverable estimates, not *economically* recoverable estimates. According to an MIT report on the future of natural gas, approximately 60 percent of the technically recoverable shale gas can be produced at a wellhead price of $6/MMBtu or less (MIT, 2010). MIT’s estimate of economically recoverable shale gas is based on a mean projection of 650 Tcf of technically recoverable gas from all shale gas plays in the U.S., so it is not directly comparable to the Marcellus Shale gas play.

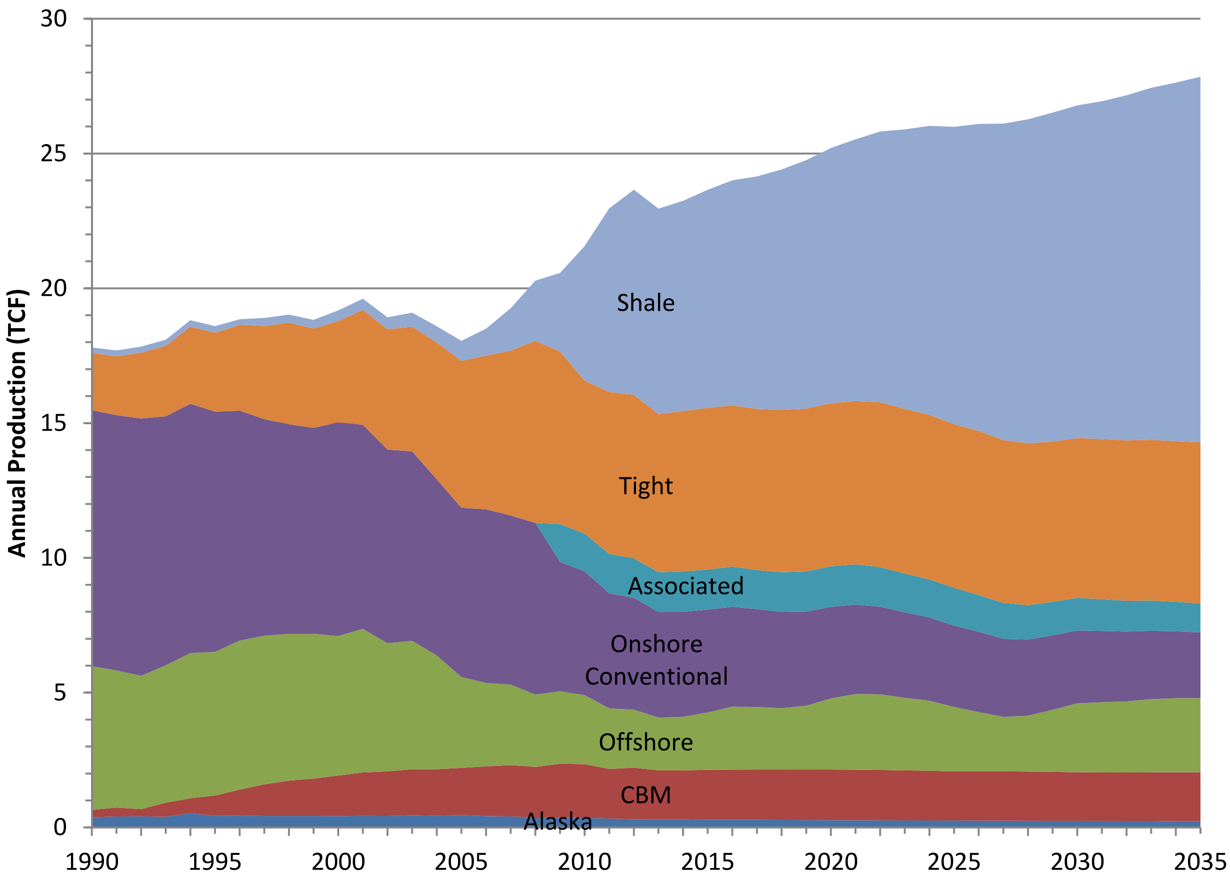
In 2009, the annual consumption of natural gas in the U.S. was 22.7 Tcf (EIA, 2011). Based on EIA projections, this consumption is expected to grow to 26.5 Tcf by 2035 (EIA, 2011). The amount of technically recoverable natural gas from Marcellus Shale, as estimated by Engelder’s projection of 489 Tcf (Engelder, 2009), is enough to meet nearly 20 years of natural gas demand. However, the estimated recoverable amount is based on an extraction period of 50 years, meaning that the 20-year supply will not be extracted within a 20-year timeframe.

Assuming a natural gas heat content of 1,027 Btu per cubic foot, 489 trillion cubic feet of natural gas translates to 489 quadrillion Btu. For comparison, the amount of recoverable coal in the U.S. is 261 billion tons (EIA, 2011), which, using a heat content of 10,000 Btu/lb., translates to 5,220 quadrillion

Btu. Thus, the amount of recoverable natural gas from Marcellus Shale is approximately 9 percent of the energy content of recoverable coal in the U.S.

The U.S. supply of natural gas consists of domestic and imported sources from both conventional and unconventional natural gas resources. The total U.S. demand for natural gas was 24.1 trillion cubic feet (Tcf) in 2010 and is projected to grow to 26.5 Tcf by 2035 EIA (EIA, 2012a). This demand is balanced by conventional and unconventional supply sources, including an increasing share of shale gas, as well as a small share of imports. Shale gas comprised 14 percent of the U.S. natural gas supply in 2009, 24 percent in 2010, and is projected to comprise 45 percent of the supply in 2035 (EIA, 2012a). The U.S. supply profile for natural gas through the year 2035 is shown in **Figure 3-3**.

Figure 3-3: Time Series Profile for U.S. Natural Gas Production (EIA, 2012a; Newell, 2011)



The historical data for U.S. natural gas production in **Figure 3-3** does not show the split between onshore conventional and associated gas prior to 2008. The data for onshore conventional production shown in **Figure 3-3** aggregates associated gas and conventional onshore gas into a single category (onshore conventional) for 1990 to 2008.

4 Environmental Analysis of Natural Gas Power

This analysis uses LCA to evaluate the environmental burdens of natural gas power. An LCA accounts for the material and energy flows of a system from cradle to grave, where the cradle is the extraction of resources from the earth and the grave is the final disposition of used products (when applicable). Direct environmental burdens, such as the extraction and combustion of natural gas, are considered along with indirect environmental burdens associated with construction and operation of facilities. Indirect burdens include energy expended during the manufacture, transport, installation, and maintenance of natural gas extraction and energy conversion equipment; the construction of natural gas conveyance and a trunkline that connects the power plant to the electricity grid; and air emissions result from the operation of an electricity transmission and distribution network. LCA is necessary to evaluate the environmental burdens from the entire life cycle (LC) of natural gas power. This inventory and analysis is ISO 14040-compliant.

4.1 LCA Scope and Boundaries

The boundaries of the LCA account for the cradle-to-grave energy and material flows for natural gas power. The boundaries include five LC stages:

LC Stage #1, Raw Material Acquisition (RMA): Accounts for the construction and operation of wells and includes hydrogen sulfide removal (sweetening) as well as other natural gas processing operations.

LC Stage #2, Raw Material Transport (RMT): Accounts for the pipeline transport of marketable natural gas from the gas processing facility to the energy conversion facility.

LC Stage #3, Energy Conversion Facility (ECF): Accounts for the conversion of natural gas to electricity, using NGCC, GTSC, or fleet average technologies.

LC Stage #4, Product Transport (PT): Accounts for the transmission and distribution of electricity from the energy conversion facility to the end user.

LC Stage #5, End Use (EU): Accounts for the consumption of electricity (this stage does not have any energy or material flows and thus serves as a placeholder in the model).

The above life cycle stages are consistent with the boundaries of other NETL LCAs, allowing comparisons among two or more technologies.

4.2 Basis of Comparison

To establish a basis for comparison, the LCA method requires specification of a functional unit, the goal of which is to define an equivalent service provided by the systems of interest. Within the cradle-to-gate boundary considered in this analysis, the functional unit is 1 MJ of fuel delivered to the gate of an energy conversion facility or other large end user. When the boundary of the analysis is expanded to include power production and transmission, the functional unit is the delivery of 1 MWh of electricity to the consumer. In both contexts, the period over which the service is provided is 30 years.

4.3 Timeframe

The environmental results are based on a 33-year period that includes 3 years of construction followed by 30-years of operation. All processes are considered to be fully operational on day one of the 30-year operating period. Construction begins in 2007, the first year of operation is 2010, and the last year of operation is 2040. All environmental consequences of construction are divided by the total electricity delivered during the 30-yr operating period in order to evenly apportion all construction burdens per unit of electricity produced. The life of all facilities and connected infrastructure is equal to that of the power plant.

4.4 Greenhouse Gas Metrics

Greenhouse gases (GHG) in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (Forster et al., 2007). The default GWP used is the 100-year time frame but, in some cases, results for the 20-year time frame are presented as well. **Table 4-1** shows the GWPs used for the GHGs inventoried in this study.

Table 4-1: IPCC Global Warming Potentials (Forster, et al., 2007)

GHG	20-year	100-year (Default)	500-year
CO_2	1	1	1
CH_4	72	25	7.6
N_2O	289	298	153
SF_6	16,300	22,800	32,600

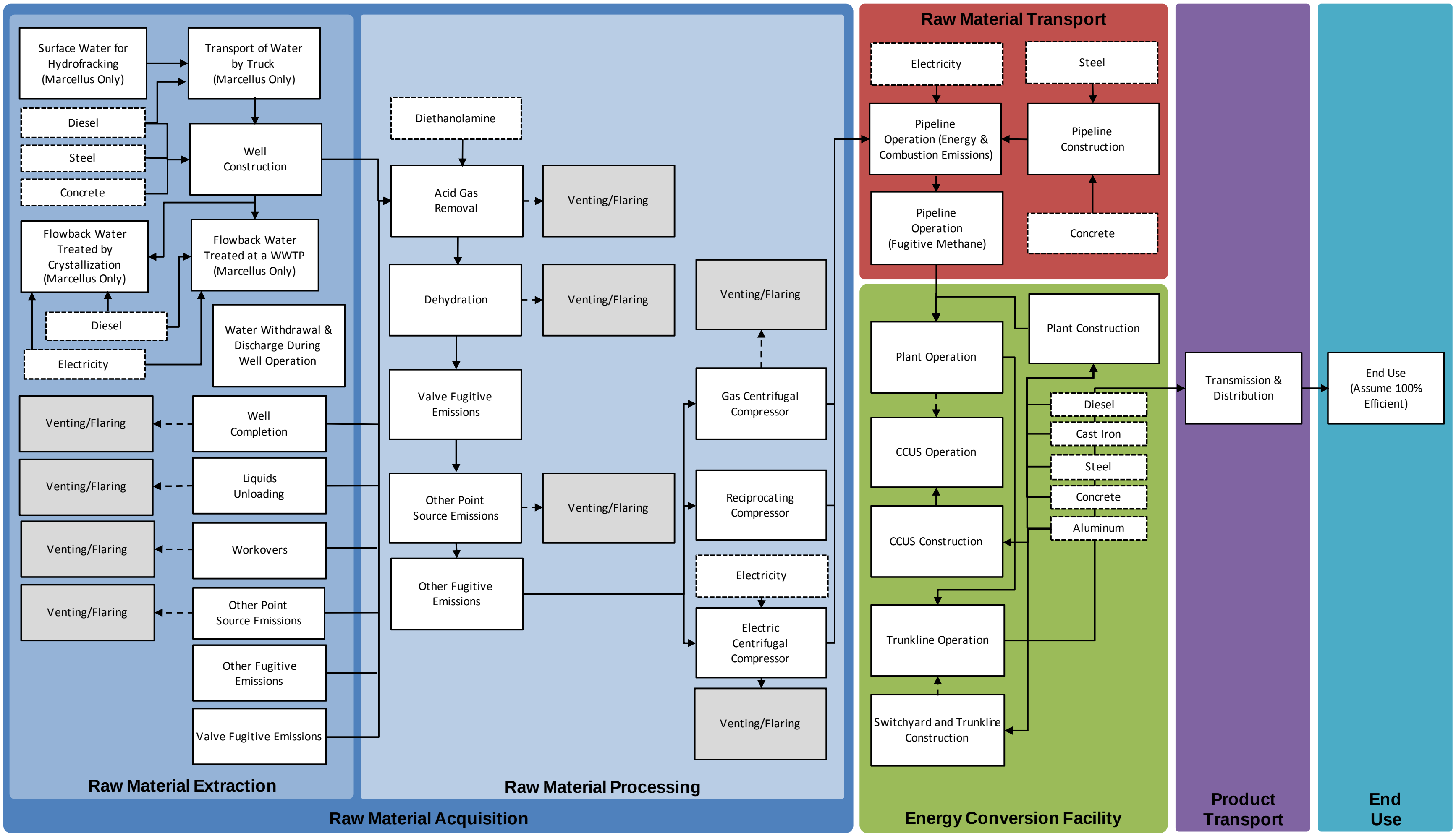
The results of this analysis also include an inventory of non-GHG emissions, effluents related to water quality, resource consumption, and water withdrawal and discharge. Equivalency factors are not applied to these metrics.

4.5 Model Structure

All results for this inventory were calculated by NETL's LCA model for natural gas power systems. This model is an interconnected network of operation and construction blocks. Each block in the model, referred to as a unit process, accounts for the key inputs and outputs of an activity. The inputs of a unit process include the purchased fuels, resources from nature (fossil feedstocks, biomass, or water), and man-made raw materials. The outputs of a unit process include air emissions, water effluents, solid waste, and product(s). The role of an LCA model is to converge on the values for all intermediate flows within the interconnected network of unit processes and then scale the flows of all unit processes to a common basis, or functional unit.

The five LC stages of the natural gas LC are illustrated in **Figure 4-1**, which shows the key unit processes of NETL's natural gas LCA model and the connections among the unit processes. These processes were assembled using the GaBi 4.0 software tool. For simplicity, the following figure shows the extraction and delivery for a generic natural gas scenario; NETL's actual model uses seven parallel modules to arrive at the LC results for a mix of seven types of natural gas. This figure also shows a breakdown of the RMA stage into extraction and processing sub-stages.

Figure 4-1: Natural Gas LCA Modeling Structure



4.6 Data Sources

The primary unit processes of this natural gas model are based on data developed by NETL. Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, or amine solvents used for gas processing, are based on third-party data.

This analysis models the extraction of natural gas by characterizing key construction and operation activities. The scope of construction includes the key metals and minerals used for foundations, structures, equipment, and other new infrastructure, as well as the energy expended to install the materials, where relevant. Data for operation activities include the fuels, raw materials, water use, and emissions associated with the daily, steady-state use of a process.

4.6.1 Sources of Natural Gas

This inventory and analysis includes results for natural gas domestically extracted from sources in the lower 48 states:

1. Conventional Onshore
2. Associated
3. Conventional Offshore
4. Tight Gas
5. Shale Formations (Barnett, Marcellus)
6. Coal Bed Methane

This is not a comprehensive list of natural gas extracted or consumed in the U.S. Natural gas extracted in Alaska, 2 percent of domestically extracted natural gas, is included as conventional onshore production. The Haynesville Shale play makes up a large portion of unconventional shale production, but it is assumed here that the Barnett play is representative of all shale production, except Marcellus Shale production. Imported natural gas (11 percent of 2010 total consumption, 86 percent of which is imported via pipeline from Canada) is not included. About 12 percent of imports in 2010 were brought in as LNG from a variety of countries of origin. While this inventory includes a profile for LNG from offshore extraction in Trinidad and Tobago, this natural gas is not included in the domestic production mix.

Table 4-2 shows the makeup of the domestic production mix in the U.S. in 2010 and the mix of conventional and unconventional extraction. In 2010, unconventional natural gas sources made up 60 percent of production and the majority of consumption in the U.S. (EIA, 2012a; Newell, 2011).

Table 4-2: Mix of U.S. Natural Gas Sources (EIA, 2012a; Newell, 2011)

Source	Conventional			Unconventional			
	Onshore	Associated	Offshore	Tight Gas	Barnett Shale	Marcellus Shale	CBM
Domestic Mix	22%	7%	12%	27%	21%	2%	9%
Type Mix	40%			60%			
	54%	16%	30%	45%	35%	4%	16%

The characteristics of these seven sources of natural gas are summarized next and include a description of the extraction technologies.

4.6.2 Natural Gas Composition

Relevant to all phases of the LC, the composition of natural gas varies considerably depending on source, and even within a source. For simplicity, a single assumption regarding natural gas composition is used, although that composition is modified as the natural gas is prepared for the pipeline (EPA, 2011a). **Table 4-3** shows the composition on a mass basis of production and pipeline quality natural gas. The pipeline quality natural gas has had water and acid gases (CO_2 and H_2S) removed, and non-methane volatile organic compounds (VOC) either flared or separated for sale. The pipeline quality natural gas has higher methane content per unit mass. The energy content does not change significantly.

Table 4-3: Natural Gas Composition on a Mass Basis

Component	Production	Pipeline Quality
CH_4 (Methane)	78.3%	92.8%
NMVOC (Non-methane VOCs)	17.8%	5.54%
N_2 (Nitrogen)	1.77%	0.55%
CO_2 (Carbon Dioxide)	1.51%	0.47%
H_2S (Hydrogen Sulfide)	0.50%	0.01%
H_2O (Water)	0.12%	0.01%

4.6.3 Data for Natural Gas Extraction

This analysis models the extraction of natural gas by characterizing key construction and operation activities at the natural gas wellhead. A summary of each unit process of NETL's model of natural gas extraction is provided below. **Appendix B** includes comprehensive documentation of the data sources and calculations for these unit processes.

4.6.3.1 Well Construction

Data for the construction and installation of natural gas wellheads are based on the energy requirements and linear drill speed of diesel-powered drilling rigs, the depths of wells, and the casing materials required for a wellbore. Construction and installation are one-time activities that are apportioned to each unit of natural gas operations by dividing all construction and installation emissions by the lifetime in years and production in million cubic feet of a typical well.

4.6.3.2 Well Completion

The data for well completion describe the emission of natural gas that occurs during the development of a well, before natural gas recovery and other equipment have been installed at the wellhead. Well completion is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from an event that occurs one time in the life of a well.

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells emit 36.65 Mcf of natural gas per completion, and unconventional wells produce 9,175 Mcf of natural gas per completion (EPA, 2011a).

Within the unconventional well category, NETL adjusted EPA's completion emission factors to account for the different reservoir pressures of unconventional wells. NETL used EPA's emission factor of 9,175 Mcf of natural gas per completion for Barnett Shale gas wells. NETL adjusted this emission factor downward for tight gas in order to account for the lower reservoir pressures of tight gas wells. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the emission factor. The production rate of tight gas wells is 40 percent of that for Barnett Shale wells (with estimated ultimate recoveries [EUR] of 1.2 Bcf for tight gas vs. 3.0 Bcf for Barnett Shale), and thus NETL assumes that the completion emission factor for tight gas wells is 3,670 Mcf of natural gas per completion (40 percent × 9,175 = 3,670).

Coal bed methane (CBM) wells also involve unconventional extraction technologies, but have lower reservoir pressures than shale gas or tight gas wells. The corresponding emission factor of CBM wells is 49.57 Mcf of natural gas per completion, which is the well completion factor that EPA reports for low pressure wells (EPA, 2011a).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. For instance, when factoring for the density of natural gas, a conventional completion emission of 36.65 Mcf is equivalent to 1,540 lbs. (699 kg) of natural gas per completion. All of the natural gas emissions during well completion are approximately 78.3 percent methane by mass.

4.6.3.3 Liquid Unloading

The data for liquids unloading describe the emission of natural gas that occurs when water and other condensates are removed from a well. These liquids impede the flow of natural gas from the well, and thus producers must occasionally remove the liquids from the wellbore. Liquid unloading is necessary for conventional gas wells—it is not necessary for unconventional wells or associated gas wells. Liquid unloading is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well.

The natural gas emissions from liquids unloading are based on the total unloading emissions from conventional wells in 2007, the number of active conventional wells in 2007, and the average frequency of liquids unloading (EPA, 2011a). The resulting emission factor for liquids unloading is 776 lbs. (352 kg) of natural gas per episode; this emission is 78.3 percent methane by mass.

4.6.3.4 Workovers

Well workovers are necessary for cleaning wells and, in the case of shale and tight gas wells, use hydraulic fracturing to re-stimulate natural gas formations. The workover of a well is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well. As stated in EPA's technical support document of the petroleum and natural gas industry (EPA, 2011a), conventional wells produce 2.454 Mcf of natural gas per workover; this emission factor is 78.3 percent methane by mass. EPA assumes that the emissions from unconventional well workovers are equal to the emission factors for unconventional well completion (EPA, 2011a). Thus, for unconventional wells, this analysis uses the same emission factors for well completion (discussed above) and well workovers.

Unlike well completions, well workovers occur more than one time during the life of a well. For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

4.6.3.5 Other Point Source Emissions

Routine emissions from natural gas extraction include gas that is released from wellhead and gathering equipment. These emissions are referred to as "other point source emissions." This analysis assumes that a portion of these emissions are flared while the balance is vented to the atmosphere. For conventional wells, 51 percent of other point source emissions are flared while for unconventional wells, a 15 percent flaring rate is used (EPA, 2011a).

Data for the other point source emissions from natural gas extraction are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for onshore and offshore wells. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other point source emissions from natural gas extraction are shown in **Table 4-4**.

4.6.3.6 Other Fugitive Emissions

Routine emissions from natural gas extraction include fugitive emissions from equipment not accounted for elsewhere in the model. These emissions are referred to as "other fugitive emissions," and cannot be captured for flaring. Data for other fugitive emissions from natural gas extraction are based on EPA data for onshore and offshore natural gas wells (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other fugitive emissions from natural gas extraction are included in **Table 4-4**.

4.6.3.7 Valve Fugitive Emissions

The extraction of natural gas uses pneumatic devices for the opening and closing of valves and other control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction site, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from valves (and other pneumatically-operated devices) are based on EPA data for onshore and offshore gas wells (EPA, 2011a). EPA's data are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate. The emission factors for fugitive valve emissions from natural gas extraction are included in **Table 4-4**.

Table 4-4: Other Point Source and Fugitive Emissions from Natural Gas Extraction

NG Extraction Emission Source	Onshore Extraction	Offshore Extraction	Units
Other Point Source Emissions	7.49E-05	3.90E-05	kg CH_4/kg NG extracted
Other Fugitive Emissions	1.02E-03	2.41E-04	kg CH_4/kg NG extracted
Valve Fugitive Emissions (including pneumatic devices)	2.63E-03	1.95E-06	kg CH_4/kg NG extracted

4.6.3.8 Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring at a natural gas well include CO_2, CH_4, and NO_X. The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.3 percent CH_4, 1.51 percent CO_2, 1.77 percent N_2, and 17.8 percent non-methane hydrocarbons (EPA, 2011a). This composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2), the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2, and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

4.6.3.9 Water Use and Produced Water

Water is an output from conventional onshore and offshore oil and natural gas extraction. For conventional gas extraction, this analysis calculates produced water per unit of natural gas production based on total figures for annual U.S. oil and gas production (ANL, 2004; DOE, 2006). The total amount of produced water is then apportioned between oil and gas production based on energy content. Recycling of the produced water for secondary extraction (e.g., pumping water into wells to facilitate gas and oil extraction) is also considered. The same data (ANL, 2004; DOE, 2006) was used to calculate the water used by associated gas operations, but was adjusted according to the ratio of energy for petroleum and natural gas produced by associated wells.

Offshore natural gas extraction withdraws water from the extraction site but returns large amounts of water to the oil or gas formation. In 2007, approximately 49 million barrels of water were injected offshore in support of natural gas production (ANL, 2009). However, the original source of this water was produced water from natural gas wells. Therefore, this analysis assumes that offshore natural gas extraction does not use additional water beyond produced water, which constitutes a net zero water use.

Water is an input to hydrofracking, which is used for recovering natural gas from tight reservoirs such as Barnett Shale and Marcellus Shale. The water inputs for the completion of a horizontal shale gas well ranges from 2 to 4 million gallons. The variability in this value is due to basin and formation characteristics (GWPC & ALL, 2009). The completion of a horizontal well in the Marcellus shale gas play uses 3.88 million gallons of water (GWPC & ALL, 2009). Water used for hydrofracking accounts for 98 percent of this water use; the remaining 2 percent accounts for water used during well drilling. These data are based on discussions with various well operators (GWPC & ALL, 2009).

The completion of shale gas wells in the Barnett shale gas play uses 1.2 and 2.7 million gallons of water for vertical and horizontal wells, respectively. The data used in the LCA model of this analysis is based on the water use and natural gas production of the entire Barnett Shale region, so it is a composite of vertical and horizontal wells and has a per well average water use of 2.3 million gallons. These data are based on 2005 well completion statistics compiled by the Texas Water Development Board (Harden, Griffin, & Nicot, 2007). In 2005 a total of 1,043 wells were completed in the Barnett Shale; 65 percent of these wells were horizontal, 23 percent were vertical, and 12 percent were unidentified (Harden, et al., 2007). As the lateral lengths for horizontal wells increase, the volume of water used for the completion of Barnett Shale wells is expected to increase. For each extra foot in lateral length, the water used for hydrofracking is expected to increase by 1,625 to 1,805 gallons (Harden, et al., 2007).

Substantial water is produced during Barnett Shale extraction operations (Harden, et al., 2007). However, the water is of poor quality and is not discharged to surface water or ground water. Instead, it is injected to deep aquifers for disposal. The water that is discharged from Marcellus Shale must be treated by a wastewater treatment plant, a crystallization system, or other treatment procedures because the geologic strata underlying the Marcellus Shale region will not support deep injection well development capacity sufficient to accept typical Marcellus Shale produced water/return flows. Produced water from conventional, associated gas, and coal bed methane extraction is sometimes treated prior to discharge. However the application of wastewater treatment to produced water was considered only for the Marcellus Shale case.

4.6.4 Data for Natural Gas Processing

This analysis models the processing of natural gas by developing an inventory of key gas processing operations, including acid gas removal, dehydration, and sweetening. Standard engineering calculations were applied to determine the energy and material balances for the operation of key natural gas equipment. A summary of NETL's natural gas processing data is provided below. **Appendix B** includes comprehensive documentation of the data sources and calculations for NETL's natural gas processing data.

4.6.4.1 Acid Gas Removal

Raw natural gas contains hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas. Amine-based processes are the predominant technologies for acid gas removal (AGR). The energy consumed by an amine reboiler accounts for the majority of energy consumed by the AGR process. Reboiler energy consumption is a function of the amine flow rate, which in turn is related to the amount of H_2S removed from natural gas. The H_2S content of raw natural gas is highly variable, with concentrations ranging from 1 part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass of raw natural gas (Foss, 2004) is modeled in this analysis.

In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb. of methane per lb. of natural gas sweetened (API, 2009).

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and natural gas product, shows that 0.013 lb. of naturally-occurring CO_2 is vented per lb. of processed natural gas.

Non-methane volatile organic compounds (NMVOC) are a co-product of AGR. A mass balance shows that 84 percent of the vented gas from the AGR process is NMVOC. They are separated and sold as a high value product on the market. Co-product allocation based on the energy content of the natural gas stream exiting the AGR unit and the NMVOC stream was used to apportion LC emissions and other burdens between the natural gas and NMVOC products.

4.6.4.2 Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

NETL's data for natural gas dehydration accounts for the reboiler used by the dehydration process, the flow rate of glycol solvent, and the methane vented from the regeneration of glycol solvent. All of these activities depend on the concentrations of gas and water that enter and exit the dehydration process. The typical water content for untreated natural gas is 49 pounds per million cubic feet (MMcf). In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs./MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is three gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gallon (EPA, 2006).

4.6.4.3 Valve Fugitive Emissions

The processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas processing plant, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from pneumatic devices are based on EPA data for gas processing plants (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific processing activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for valve fugitive emissions from natural gas processing is included in **Table 4-5**.

4.6.4.4 Other Point Source Emissions

Routine emissions from natural gas processing include gas that is released from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other point source emissions." This analysis assumes that 100 percent of other point source emissions from natural gas processing are captured and flared.

Data for the other point source emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other point source emissions from natural gas processing is included in **Table 4-5**.

4.6.4.5 Other Fugitive Emissions

Routine emissions from natural gas processing include fugitive emissions from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions" and cannot be captured for flaring.

Data for the other fugitive emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the CH_4 emission rate by the natural gas processing rate in 2006. The emission factor for other fugitive emissions from natural gas processing is included in **Table 4-5**.

Table 4-5: Other Point Source and Fugitive Emissions from Natural Gas Processing

NG Processing Emission Source	Value	Units
Other Point Source Emissions	3.68E-04	kg CH_4/kg NG processed
Other Fugitive Emissions	8.25E-04	kg CH_4/kg NG processed
Valve Fugitive Emissions (including pneumatic devices)	6.33E-06	kg CH_4/kg NG processed

4.6.4.6 Venting and Flaring

The venting and flaring process for natural gas processing is similar to that of natural gas extraction, described in **Section 4.6.3.8**, except all of the other point source emissions at the natural gas processing plant are flared. The combustion products of flaring at a natural gas processing plant include CO_2, CH_4, and NO_X. The mass composition of pipeline quality natural gas is 92.8 percent CH_4, 0.47 percent CO_2, 0.55 percent N_2, and 5.5 percent NMVOCs; this composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2); the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2; and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

4.6.4.7 Natural Gas Compression

Compressors are used to increase the natural gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. Three types of compressors are used at natural gas processing plants: gas-powered reciprocating compressors, gas-powered centrifugal compressors, and electrically-powered centrifugal compressors.

Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Burklin & Heaney, 2006).

Gas-powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures).

If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a populated area. An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine.

Centrifugal compressors (both gas-powered and electrically-powered) lose natural gas through a process called wet seal degassing, which involves the regeneration of lubricating oil that is circulated between the compressor shaft and housing. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010) and implies a wet seal degassing emission factor of 0.0069 lb. of natural gas/lb. of processed natural gas.

4.6.5 Data for Natural Gas Transport

This analysis models the transport of natural gas by characterizing key construction and operation activities for pipelines used by the U.S. natural gas transmission system.

4.6.5.1 Natural Gas Transport Construction

The construction of a natural gas pipeline is based on the linear density, material requirements, and length for pipeline construction. A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Construction is a one-time activity that is apportioned to each unit of natural gas transport by dividing all construction burdens by the book life in years and throughput in million cubic feet of the pipeline.

4.6.5.2 Natural Gas Transport Operations

The U.S. has an extensive natural gas pipeline network that connects natural gas supplies and markets. Compressor stations are necessary every 50 to 100 miles along the natural gas transmission pipelines in order to boost the pressure of the natural gas. Compressor stations consist of centrifugal and reciprocating compressors. Most natural gas compressors are powered by natural gas, but, when electricity is available, electrically-powered compressors are used. Data for the operation of a natural gas pipeline are based on national inventory data for methane emissions from natural gas transmission (EPA, 2011b), a database compiled by the Interstate Natural Gas Association of America (Hedman, 2008), and personal communication with El Paso Pipeline Group (George, 2011). The estimated transport capacity of U.S. national gas pipelines (in ton-miles) is applied to the other pipeline variables in order to correlate pipeline emissions with pipeline distance.

4.6.6 Data for Other Energy Sources

In addition to the extraction and delivery of natural gas, it is also helpful to model the extraction and delivery of other fossil fuels, such as coal, to provide further context for the life cycle burdens of natural gas.

Coal was chosen as a comparable fossil energy source to natural gas. Because a mix of natural gas sources is developed to represent a domestic production average, a similar method was followed for developing an average domestic coal extraction and transport profile. Two sources of coal are used in the mix, and a wide range of uncertainty is applied to sensitive parameters to ensure the domestic average is captured. The two coal sources are:

- Illinois No. 6 Underground-mined Bituminous
- Powder River Basin Surface-mined Sub-bituminous

More data on coal extraction and delivery are provided in **Appendix B**.

4.6.7 Data for Energy Conversion Facilities

The simplest way to compare the full LC of coal and natural gas is to produce electricity, although there are alternative uses for both feedstocks. To compare inputs of coal and natural gas on a common basis, production of baseload electricity was chosen. Seven different power plant options are used – three for natural gas and four for coal. Three of the options include carbon capture technology and sequestration infrastructure. Two of the options are U.S. fleet averages based on eGRID data, while the remainder is NETL baseline models.

4.6.7.1 Natural Gas Combined Cycle (NGCC)

The NGCC power plant is based on a 555 MW net thermoelectric generation facility with two parallel, advanced F-Class gas fired combustion turbines. Each combustion turbine is followed by a heat recovery steam generator that produces steam that is fed to a single steam turbine. The NGCC plant consumes natural gas at a rate of 75,900 kg/hr and has an 85 percent capacity factor. Other details on the fuel consumption, water withdrawal and discharge, and emissions are detailed in NETL's bituminous baseline (NETL, 2010a). The carbon capture scenario for NGCC is configured with a Fluor Econamine℠ CO_2 capture system that recovers 90 percent of the CO_2 in the flue gas. Full description, input data, and results for this power plant can be found in the report, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant* (NETL, 2010d).

4.6.7.2 Gas Turbine Simple Cycle (GTSC)

A GTSC power plant is modeled based on a plant that uses two parallel, advanced F-Class natural gas-fired CTGs. The performance of the GTSC plant was adapted from NETL baseline of NGCC power by considering only the streams that enter and exit the CTGs and not accounting for any process streams related to the heat recovery systems used by combined cycles. The output of the GTSC plant is 360 MW net.

4.6.7.3 U.S. 2007 Average Baseload Natural Gas

The average baseload natural gas plant was developed using data from eGRID on plant efficiency (EPA, 2010a). The most recent eGRID data is representative of 2007 electricity production. The average heat rate was calculated for plants with a capacity factor over 60 percent and a capacity greater than 200 MW to represent those plants performing a baseload role. The average efficiency (weighted by production, so the efficiency of larger, more productive plants had more weight) was 48.4 percent. This efficiency is applied to the energy content of natural gas (which ranges from 990 and 1,030 Btu/cf) in order to determine the feed rate of natural gas per average U.S. natural gas power. Similarly, the carbon content of natural gas (which ranges from 72 percent to 80 percent) is factored by the feed rate of natural gas, 99 percent oxidation efficiency, and a molar ratio of 44/12 to determine the CO_2 emissions per unit of electricity generation.

4.6.7.4 Integrated Gasification Combined Cycle (IGCC)

The plant modeled is a 640 MW net IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A slurry of Illinois No. 6 coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is cleaned before being fed to two advanced F-Class combustion turbine/generators. The exhaust gas from each combustion turbine is fed to an individual heat recovery steam generator where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator. A syngas expander generates additional power.

This facility has a capacity factor of 80 percent. For the carbon capture case, the plant is a 556 MW net facility with a two-stage Selexol solvent process to capture both sulfur compounds and CO_2 emissions. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data, and results for this power plant can be found in the report, *Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant* (NETL, 2010c).

4.6.7.5 Supercritical Pulverized Coal (SCPC)

This plant is a 550 MW net facility located at a greenfield site in southeast Illinois utilizing a single-train supercritical steam generator. Illinois No. 6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator. Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide, a combination of low-nitrogen oxide burners and overfire air, a selective catalytic reduction unit that removes nitrogen oxides, a pulse jet fabric filter that removes particulates, and mercury (Hg) reductions via co-benefit capture.

The carbon capture case is a 546 MW net plant configured with 90 percent carbon capture and sequestration (CCS) utilizing an additional sulfur polishing step to reduce sulfur content and a Fluor Econamine FG Plus℠ process. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant* (NETL, 2010e).

4.6.7.6 Existing Pulverized Coal (EXPC)

This case is an existing pulverized coal power plant that fires coal at full load without capturing CO_2 from the flue gas. This case is based on a 434 MW net plant with a subcritical boiler that fires Illinois No. 6 coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. The net efficiency of this power plant is 35 percent.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant* (NETL, 2010b).

4.6.7.7 U.S. 2007 Average Baseload Coal

Using a similar method to the fleet average natural gas baseload plant, a mean and weighted average efficiency of 33.1 percent were pulled from eGRID. The heating value of coal and the heat rate of the power plant were used to determine the feed rate of coal to the power plant.

For each option, the transmission and distribution (T&D) of electricity incurs a 7 percent loss, resulting in the production of additional electricity and extraction of necessary fuel to overcome this loss. All upstream LC stages scale according to this loss factor.

Construction is included in the four NETL developed models. It accounts for less than 1 percent of overall GHG impact, and so was excluded from the total for the fleet average plants.

4.6.8 Summary of Key Model Parameters

The following table summarizes the key parameters that affect the LC results for the extraction of natural gas. This includes the amounts of CH_4 emissions from routine activities, frequency and emission rates from non-routine operations, depths of different well types, flaring rates of vented gas, production rates, and domestic supply shares.

Table 4-6: Key Parameters for Seven Natural Gas Sources

<table>
<tr><th>Property (Units)</th><th>Onshore</th><th>Associated</th><th>Off-shore</th><th>Tight Gas</th><th>Barnett Shale</th><th>Marcellus Shale</th><th>CBM</th></tr>
<tr><td colspan="8">Natural Gas Source</td></tr>
<tr><td>Contribution to 2010 U.S. Domestic Supply</td><td>22%</td><td>6.6%</td><td>12%</td><td>27%</td><td>21%</td><td>2.5%</td><td>9.4%</td></tr>
<tr><td>Average Production Rate (Mcf/day) Low</td><td>46</td><td>85</td><td>1,960</td><td>77</td><td>192</td><td>201</td><td>73</td></tr>
<tr><td>Expected Value</td><td>66</td><td>121</td><td>2,800</td><td>110</td><td>274</td><td>297</td><td>105</td></tr>
<tr><td>High</td><td>86</td><td>157</td><td>3,641</td><td>143</td><td>356</td><td>450</td><td>136</td></tr>
<tr><td>EV Estimated Ultimate Recovery (BCF)</td><td>0.72</td><td>1.32</td><td>30.7</td><td>1.20</td><td>3.00</td><td>3.25</td><td>1.15</td></tr>
<tr><td colspan="8">Natural Gas Extraction Well</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="3">51% (41 - 61%)</td><td colspan="4">15% (12 - 18%)</td></tr>
<tr><td>Well Completion (Mcf natural gas/episode)</td><td colspan="3">37.0</td><td>3,670</td><td colspan="2">9,175</td><td>49.6</td></tr>
<tr><td>Well Workover (Mcf natural gas/episode)</td><td colspan="3">2.44</td><td>3,670</td><td colspan="2">9,175</td><td>49.6</td></tr>
<tr><td>Lifetime Well Workovers (Episodes/well)</td><td colspan="3">1.1</td><td colspan="4">3.5</td></tr>
<tr><td>Liquids Unloading (Mcf natural gas/episode)</td><td>23.5</td><td>N/A</td><td>23.5</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Lifetime Liquid Unloadings (Episodes/well)</td><td>930</td><td>N/A</td><td>930</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td>Valve Emissions, Fugitive (lb. CH_4/Mcf)</td><td colspan="2">0.11</td><td>0.0001</td><td colspan="4">0.11</td></tr>
<tr><td>Other Sources, Point Source (lb. CH_4/Mcf)</td><td colspan="2">0.003</td><td>0.002</td><td colspan="4">0.003</td></tr>
<tr><td>Other Sources, Fugitive (lb. CH_4/Mcf)</td><td colspan="2">0.043</td><td>0.01</td><td colspan="4">0.043</td></tr>
<tr><td colspan="8">Acid Gas Removal (AGR) and CO_2 Removal Unit</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="7">100%</td></tr>
<tr><td>CH_4 Absorbed (lb. CH_4/Mcf)</td><td colspan="7">0.04</td></tr>
<tr><td>CO_2 Absorbed (lb. CO_2/Mcf)</td><td colspan="7">0.56</td></tr>
<tr><td>H_2S Absorbed (lb. H_2S/Mcf)</td><td colspan="7">0.21</td></tr>
<tr><td>NMVOC Absorbed (lb. NMVOC/Mcf)</td><td colspan="7">6.59</td></tr>
<tr><td colspan="8">Glycol Dehydrator Unit</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="7">100%</td></tr>
<tr><td>Water Removed (lb. H_2O/Mcf)</td><td colspan="7">0.045</td></tr>
<tr><td>CH_4 Emission Rate (lb. CH_4/Mcf)</td><td colspan="7">0.0003</td></tr>
<tr><td colspan="8">Valves & Other Sources of Emissions</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="7">100%</td></tr>
<tr><td>Valve Emissions, Fugitive (lb. CH_4/Mcf)</td><td colspan="7">0.0003</td></tr>
<tr><td>Other Sources, Point Source (lb. CH_4/Mcf)</td><td colspan="7">0.02</td></tr>
<tr><td>Other Sources, Fugitive (lb. CH_4/Mcf)</td><td colspan="7">0.03</td></tr>
<tr><td colspan="8">Natural Gas Compression at Gas Plant</td></tr>
<tr><td>Compressor, Gas-Powered Reciprocating (%)</td><td>100%</td><td>100%</td><td></td><td>100%</td><td>75%</td><td>100%</td><td>100%</td></tr>
<tr><td>Compressor, Gas-Powered Centrifugal (%)</td><td></td><td></td><td>100%</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Compressor, Electric Centrifugal (%)</td><td></td><td></td><td></td><td></td><td>25%</td><td></td><td></td></tr>
<tr><td colspan="8">Natural Gas Emissions on Transmission Infrastructure</td></tr>
<tr><td>Pipeline Transport Distance (mi.)</td><td colspan="7">604 (483 - 725)</td></tr>
<tr><td>Pipeline Emissions, Fugitive (lb. CH_4/Mcf-mi)</td><td colspan="7">0.0003</td></tr>
<tr><td colspan="8">Natural Gas Compression on Transmission Infrastructure</td></tr>
<tr><td>Distance Between Compressors (mi)</td><td colspan="7">75</td></tr>
<tr><td>Compressor, Gas-powered Reciprocating (%)</td><td colspan="7">78%</td></tr>
<tr><td>Compressor, Gas-powered Centrifugal (%)</td><td colspan="7">19%</td></tr>
<tr><td>Compressor, Electrical, Centrifugal (%)</td><td colspan="7">3%</td></tr>
</table>

4.7 Land Use Change

Analysis of land use effects is considered a central component of an LCA under both the International Standards Organization (ISO) 14044 and the American Society for Testing and Materials (ASTM) standards. Additionally, the U.S. EPA's Renewable Fuel Standard Program (RFS) (EPA, 2010b) includes a method for assessing land use change and associated GHG emissions. The land use model of this analysis is consistent with this method. It quantifies both the area of land changed, as well as the GHG emissions associated with that change, for direct and select indirect land use impacts.

4.7.1 Definition of Direct and Indirect Impacts

Land use effects can be roughly divided into direct and indirect. In the context of this study, direct land use effects occur as a result of processes within the natural gas life cycle boundary. Direct land use change is determined by tracking the change from an existing land use type (native vegetation or agricultural lands) to a new land use that supports production; examples include gas wells, regasification facilities, biomass feedstock cropping, and energy conversion facilities.

Indirect land use effects are changes in land use that occur as a result of the direct land use effects. For instance, if the direct effect is the conversion of agricultural land to land used for energy production, an indirect effect might be the conversion to new farmland of native vegetation, but at a remote location, in order to meet ongoing food supply/demand. This specific case of indirect land use change has been studied in detail by the U.S. EPA (EPA, 2010b) and other investigators, and sufficient data are available to enable consideration of this specific case of indirect land use within this study. There are also other types of indirect land use change that could potentially occur as a result of the installation of new energy production and conversion facilities. For instance, the installation of a new NGCC power plant at a rural location could result in the migration of power plant employees to the site, causing increased urbanization in surrounding areas. However, due to the uncertainty in predicting and quantifying this and other less studied indirect effects, such phenomena were not considered in this analysis.

4.7.2 Land Use Metrics

A variety of land use metrics that seek to numerically quantify changes in land use have been devised in support of LCAs. Two common metrics in support of an LCA are transformed land area (square meters of land transformed) and GHG emissions (kg CO_2e). The transformed land area metric estimates the area of land that is altered from a reference state, while the GHG metric quantifies the amount of carbon emitted in association with that change. **Table 4-7** summarizes the land use metrics included in this analysis.

Table 4-7: Primary Land Use Metrics

Metric Title	Description	Units	Type of Impact
Transformed Land Area	Area of land that is altered from its original state to a transformed state during construction and operation of the advanced energy conversion facilities	m^2 (acres)	Direct and Indirect
Greenhouse Gas Emissions	Emissions of GHGs associated with land clearing/transformation, including emissions from aboveground biomass, belowground biomass, soil organic matter, and lost forest sequestration	kg CO_2e (lbs CO_2e)	Direct and Indirect

This assessment of GHG emissions from land use change includes those emissions that would result from the direct and indirect activities associated with the following:

- Quantity of GHGs emitted due to biomass clearing during construction of each facility
- Quantity of GHGs emitted due to oxidation of soil carbon and underground biomass following land transformation, for each facility
- Evaluation of ongoing carbon sequestration that would have occurred under existing conditions, but did not occur under study/transformed land use conditions

Additional land use metrics, such as potential damage to ecosystems or species, water quality changes, changes in human population densities, quantification of land quality (e.g., farmland quality), and many other land use metrics may conceivably be included in the land use analysis of an LCA. However, much of the data needed to support accurate analysis of these metrics are severely limited in availability (Bauer, Dubreuil, & Gaillard, 2007; Scholz, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area and GHG emissions are quantified for this study.

4.7.3 Land Use Calculation Method

As discussed previously, the land use metrics that will be used for this analysis quantify the land area that is transformed from its original state due to production of electricity, including supporting facilities. Calculations are based on a 30-year study period, or as relevant for each facility as discussed in the following text.

4.7.3.1 Transformed Land Area

The transformed land area metric was evaluated using assumptions regarding facility size and were based on prior NETL documentation (NETL, 2010b), as well as satellite imagery and total statewide land use patterns available from the U.S. Department of Agriculture (USDA) (USDA, 2005), to assess and quantify original state land use. Land use requirements associated with natural gas extraction were taken from a variety of sources specific to each natural gas source (AEC, 2009; NYSDEC, 2009; Truestar, 2008) except tight gas, which was assumed to require the same land area as Marcellus Shale due to lack of available data. This was completed for each relevant facility including natural gas extraction, pipelines, LNG transport facilities, the NGCC plant, CCS pipeline, and other installed facilities as relevant, for all LC stages. No facilities or other changes were required for the study under LC Stage #5, such that land use would potentially be affected.

For indirect land use change, consistent with EPA's Renewable Fuel Standard analysis, it was assumed that 30 percent of all agricultural land that was lost as a result of the installation of facilities within the study resulted in the creation of new agricultural land at a remote location within the U.S. The creation of new agricultural land, in turn, was assumed to result in the conversion of either forest or grassland/pasture to farmland, according to regional land use characteristics identified by USDA (USDA, 2005).

4.7.3.2 Greenhouse Gas Emissions

GHG emissions due to land use change were evaluated based upon the U.S. EPA's method for the quantification of GHG emissions, in support of the RFS (EPA, 2010b). EPA's analysis quantifies GHG emissions that are expected to result from land use changes from forest, grassland, savanna, shrubland, wetland, perennial, or mixed land use types to agricultural cropland, grassland, savanna, or perennial land use types. Relying on an evaluation of historic land use change completed by Winrock, EPA calculated a series of GHG emission factors for the following criteria: change in biomass carbon stocks, lost forest sequestration, annual soil carbon flux, CH_4 emissions, NO_X emissions, annual peat emissions, and fire emissions, that would result from land conversion over a range of timeframes. EPA's analysis also includes calculated reversion factors, for the reversion of land use from agricultural cropland, grassland, savanna, and perennial, to forest, grassland, savanna, shrub, wetland, perennial, or mixed land uses. Emission factors considered for reversion were change in biomass carbon stocks, change in soil carbon stocks, and annual soil carbon uptake over a variety of timeframes. Each of these emission factors, for land conversion and reversion, was included for a total of 756 global countries and regions within countries, including the 48 contiguous states. Based on the land use categories (forest, grassland, and agriculture/cropland) that were affected by study facilities, EPA's emission factors were applied on a statewide or regional basis.

GHG emissions from indirect land use were quantified only for the displacement of agriculture, and not for the displacement of other land uses. Indirect land use GHG emissions were calculated based on estimated indirect land transformation values, as discussed previously. Then, EPA's GHG emission factors for land use conversion were applied to the indirect land transformation values, according to transformed land type and region, and total indirect land use GHG emissions were calculated.

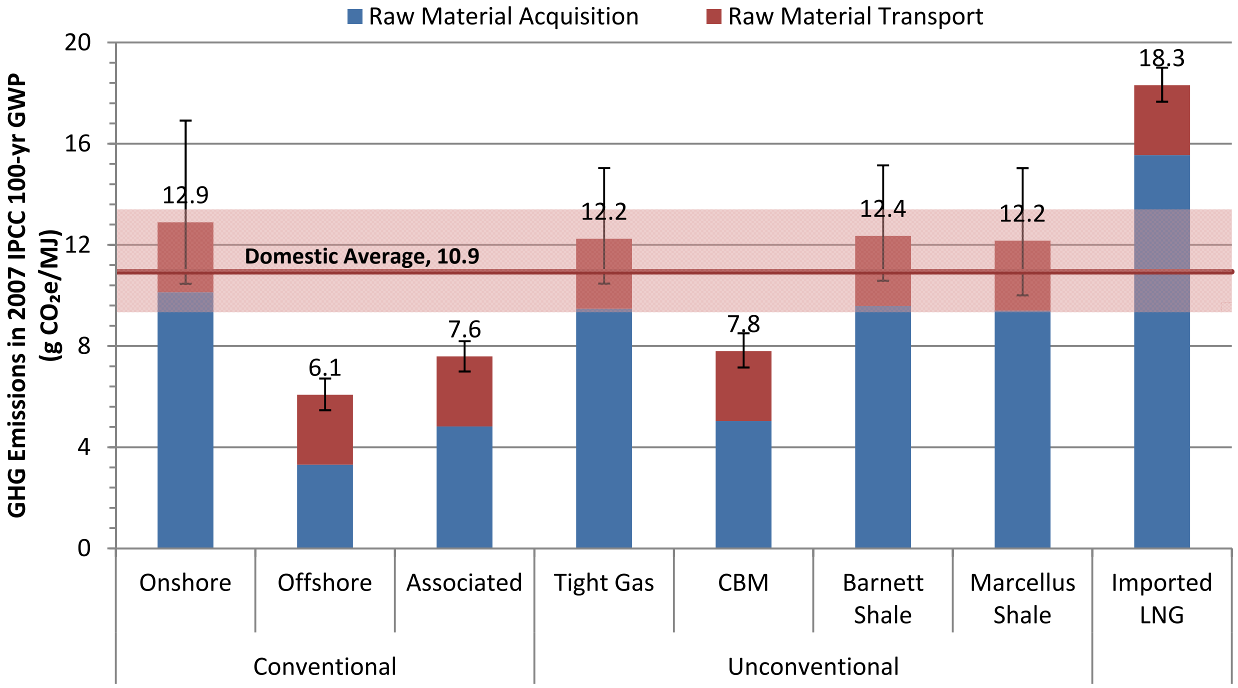
4.8 Environmental Results

The results of the LCA model allow conclusions related to GHG and other emissions, water use, water quality, and land use.

4.8.1 GHG Analysis of Natural Gas

Figure 4-2 shows the upstream GHG emissions of seven sources of domestic gas and imported liquefied natural gas broken out by LC stage. These results are based on IPCC 100-year GWP. The domestic average of 10.9 g CO_2e/MJ and its associated uncertainty are shown overlaying the results for the other types of gas. This average is calculated using the percentages shown in **Table 4-2**.

Figure 4-2: Upstream Natural Gas GHG Emissions by Source[1]



The RMT result is the same for all types of natural gas because natural gas is a commodity that is indistinguishable once put on the transport network, making the transport distance the same for all types of natural gas. The distance parameter is adjustable, so if a natural gas type with a short distance to markets were evaluated, the RMT value would be smaller.

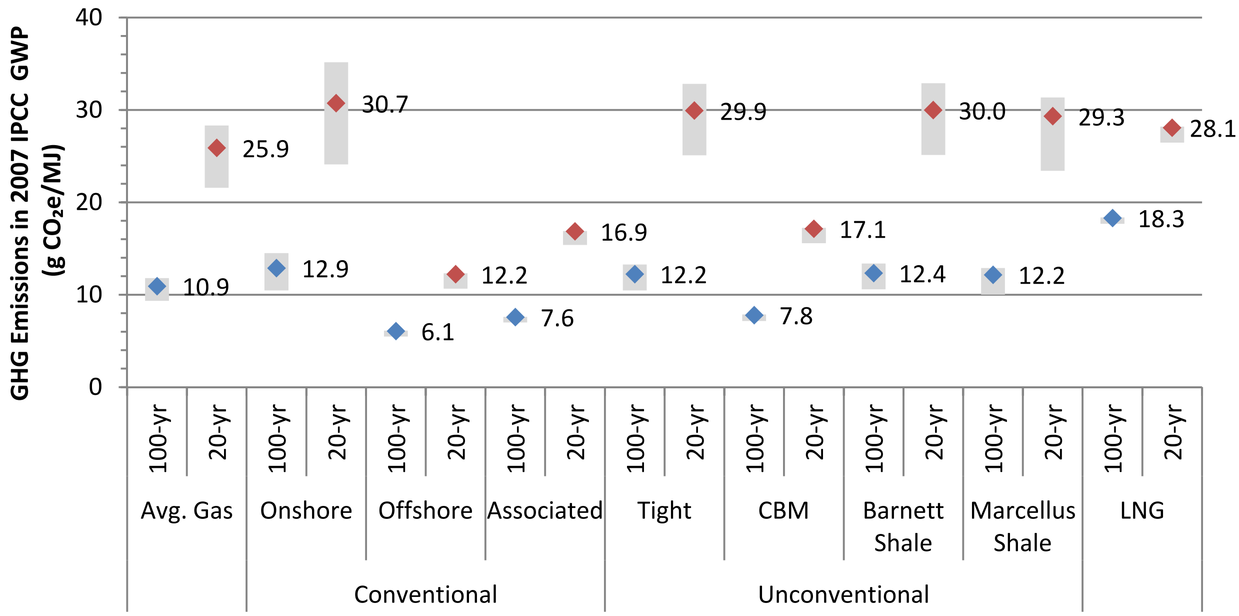
Offshore natural gas has the lowest GHGs of any source. This is due to the high production rate of offshore wells and an increased emphasis on controlling methane emissions for safety and risk-mitigation reasons.

Imported gas has significantly higher GHGs than even domestic unconventional extraction. It is fundamentally an offshore extraction process, which has the lowest GHGs of all the sources. The additional burdens are due to the refrigeration, ocean transport, and liquefaction processes.

Uncertainty is highest for the unconventional sources due to high episodic emissions (well completions, workovers, etc.) and a wide range of observed production rates to allocate those emissions.

[1] Results are based on average production rates of natural gas wells (not marginal production) and are expressed using 2007 IPCC 100-yr global warming potentials.

Figure 4-3: GHG Emissions by Source and GWP for Natural Gas Extraction and Transport



The results in **Figure 4-3** show the total CO_2e results from **Figure 4-2** across two sets of global warming potentials (detailed in **Table 4-1**). Converting the inventory of GHGs to 20-year GWP, where the CH_4 factor increases from 25 to 72, magnifies the difference between conventional and unconventional sources of natural gas, and the importance of CH_4 losses to the cradle-to-gate GHG results.

The following Sankey diagram (**Figure 4-4**) shows the reduction in natural gas (not solely CH_4) from extraction to delivery at the plant gate. This information is not weighted by GWP. **Table 4-8** shows the same information in table form.

Of the natural gas extracted from the ground, only 89 percent is delivered to the plant or city gate; 11 percent is either used internally for power (released at a point source and then flared, if applicable) or lost as a fugitive emission. It is important to recognize that not all of this gas is emitted to the atmosphere. In fact, 57 percent of the reduction in natural gas is used to power various processing equipment, most significantly to compressors providing motive force for the natural gas. Further, 28 percent are point source emissions, generally concentrated enough to be flared; this is important, when seen from a climate change perspective, as it converts the methane to carbon dioxide. Only 15 percent of emissions are considered fugitive (spatially separated emissions difficult to capture or control).

Figure 4-4: Cradle-to-Gate Reduction in Extracted Natural Gas

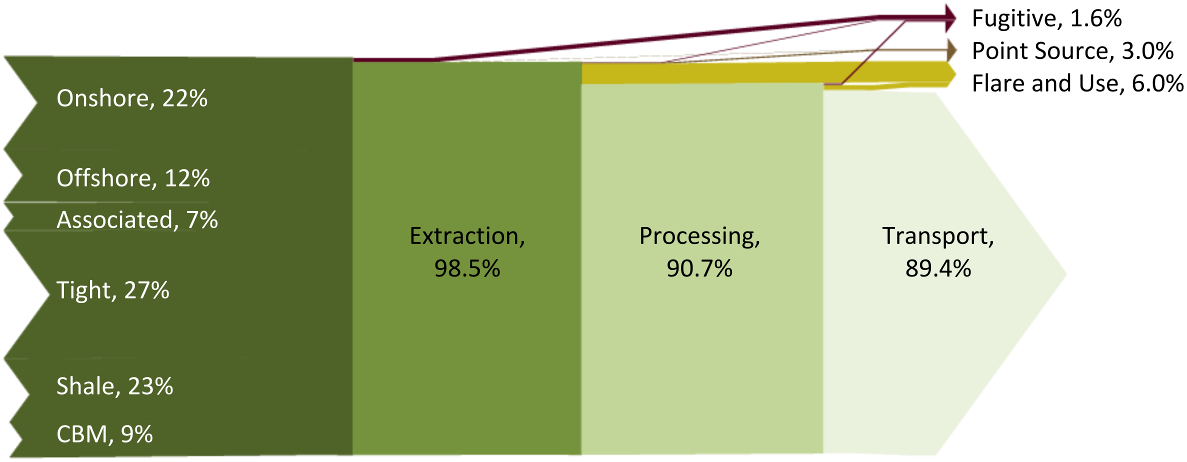


Table 4-8: Natural Gas Losses from Extraction and Transportation

Process	Raw Material Acquisition		Transport	Total
	Extraction	Processing		
Extracted from Ground	100%			100%
Fugitive Losses	1.00%	0.11%	0.47%	1.58%
Point Source Losses (Vented or Flared)	0.52%	2.43%	0%	2.95%
Flare and Fuel Use	0%	5.20%	0.85%	6.05%
Delivered to End User				89.4%

By expanding the underlying data in the LCA model, a better understanding of the key contributions to natural gas emissions can be achieved. **Figure 4-5** through **Figure 4-7** show the GHG contribution of specific extraction and transport activities for onshore conventional natural gas, Barnett Shale, and Marcellus Shale. These figures further show the contribution of CH_4, N_2O and CO_2 to the total GHGs. Similar data exists for each source of natural gas, as well as for the domestic average.

Figure 4-5: Expanded Upstream GHG Emissions from Onshore Natural Gas

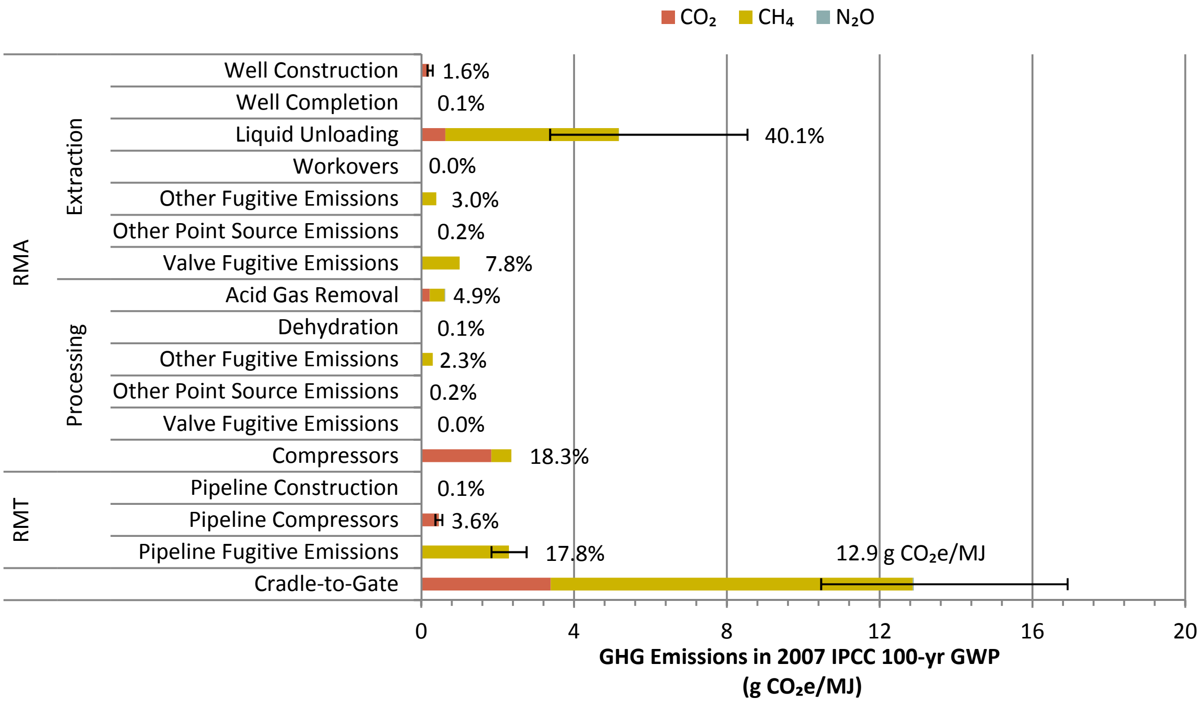


Figure 4-6: Expanded Upstream GHG Emissions from Barnett Shale Natural Gas

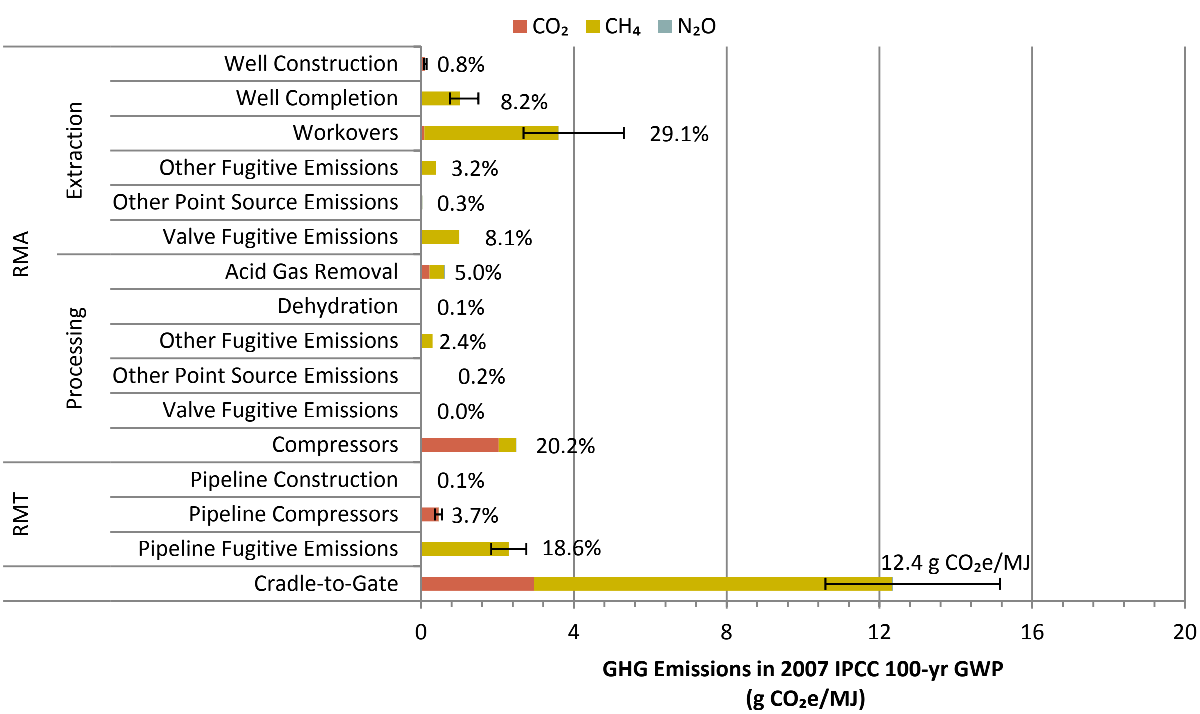
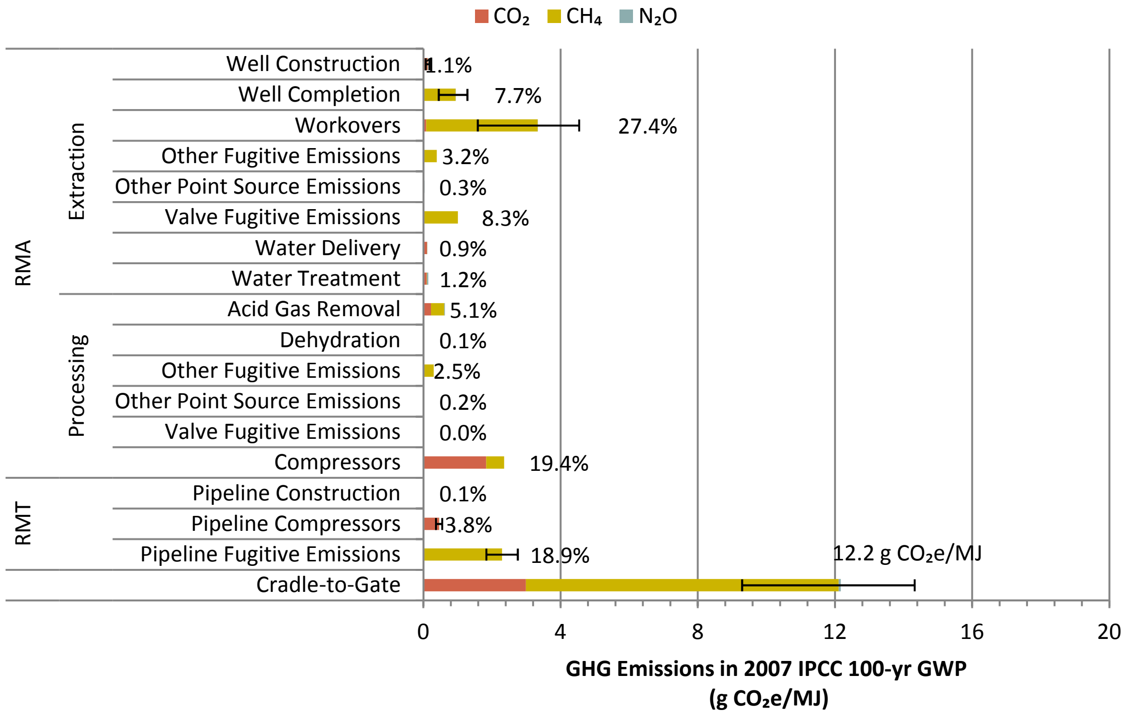


Figure 4-7: Expanded Upstream GHG Emissions from Marcellus Shale Natural Gas



The above figures show how important CH_4 is to the total GHG emissions. In most energy systems, CO_2 is the primary concern, but for natural gas extraction, processing, and transport, the CH_4 drives the result and most of the uncertainty. With unconventional gas, the importance (and associated uncertainty) associated with episodic emissions, such as well completion and workover, can be seen as well. Well construction, on the other hand, contributes less than 1 percent to the total. Moreover, from the compressors at the last stage of the processing step along with the compressor operations and fugitive emissions on the pipeline, the importance of transport can be seen from these results.

This analysis uses a parameterized modeling approach that allows the alteration and subsequent analysis of key variables. Doing so allows the identification of variables that have the greatest effect on results. Sensitivity results are shown in the following figures (**Figure 4-8** through **Figure 4-10**). In these figures, the percentages shown on the horizontal axes are relative to a unit change in parameter value; all parameters are changed by the same percentage, allowing comparison of the magnitude of change to the result across all parameters. Positive results indicate that an increase in the parameter leads to an increase in the result. A negative value indicates an inverse relationship; an increase in the parameter would lead to a decrease in the overall result.

For example, a 5 percent increase in the production rate for Barnett Shale would result in a 1.9 percent (5 percent of 37.8 percent) decrease in cradle-to-gate GHGs, from 12.4 to 12.2 g CO_2e/MJ. A corresponding 5 percent increase in onshore production rate results in a 2.1 percent decrease to 12.6 g CO_2e/MJ. Thus, The GHG emissions from onshore production are more sensitive to changes in production rate than that in Barnett Shale production.

Figure 4-8: Sensitivity of Upstream Onshore NG GHGs to Parameter Changes

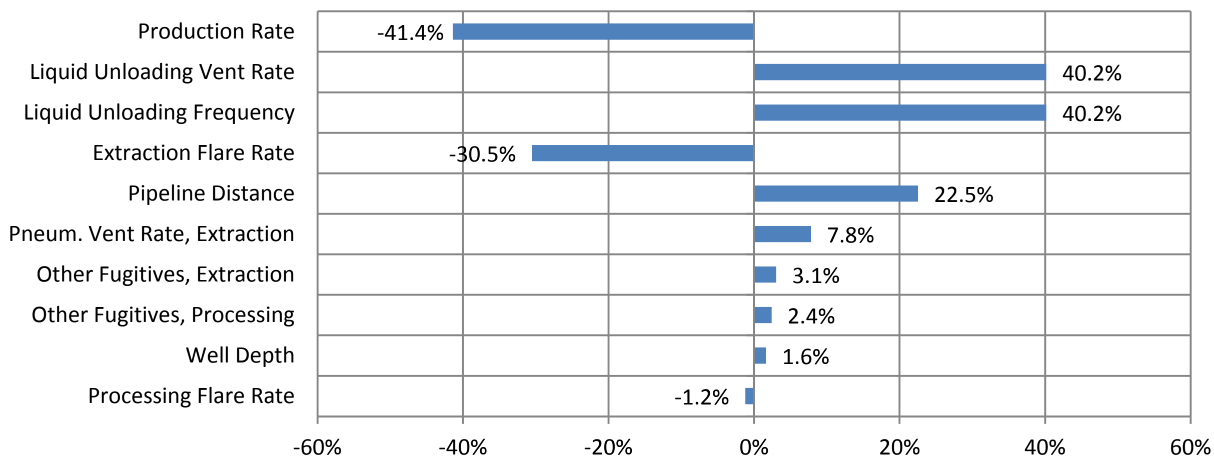


Figure 4-9: Sensitivity of Upstream Barnett Shale NG GHGs to Parameter Changes

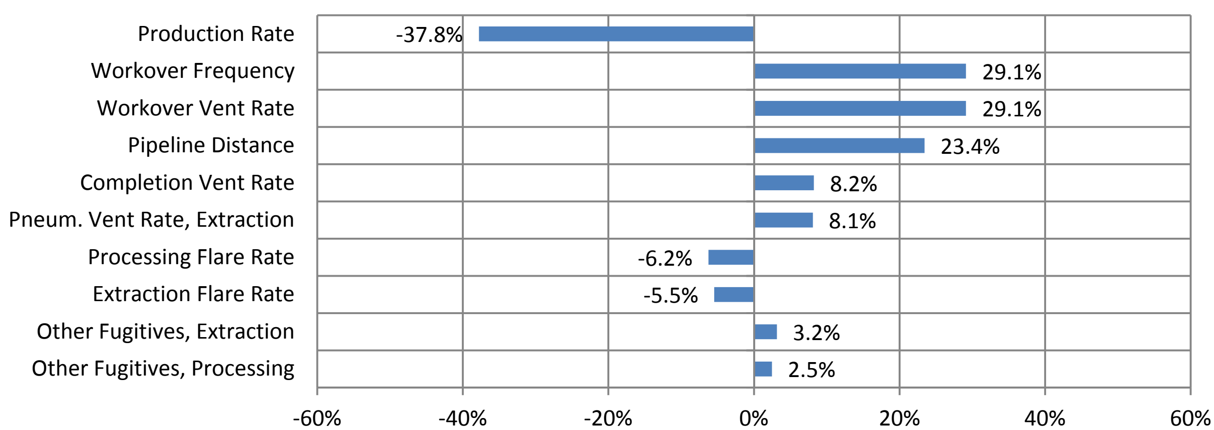
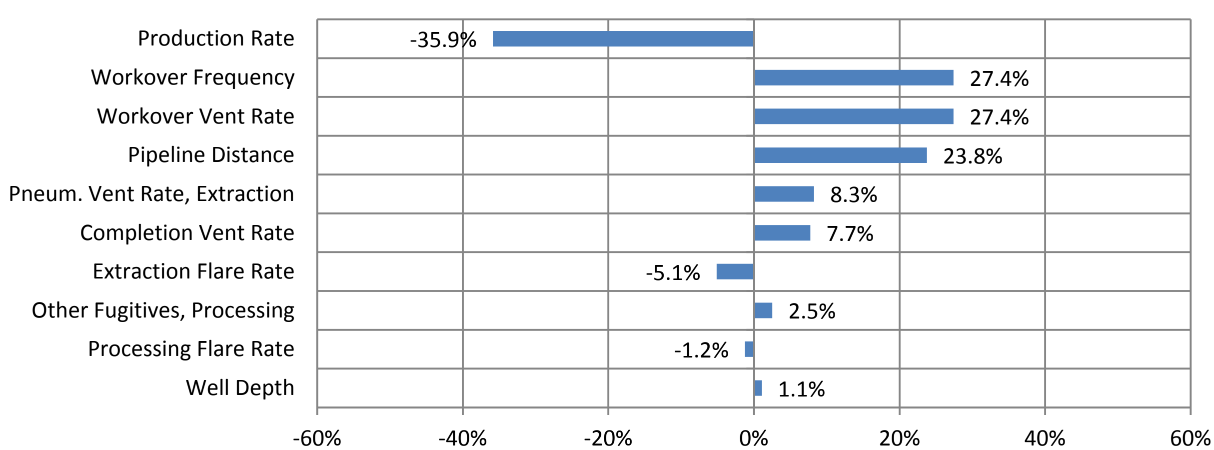


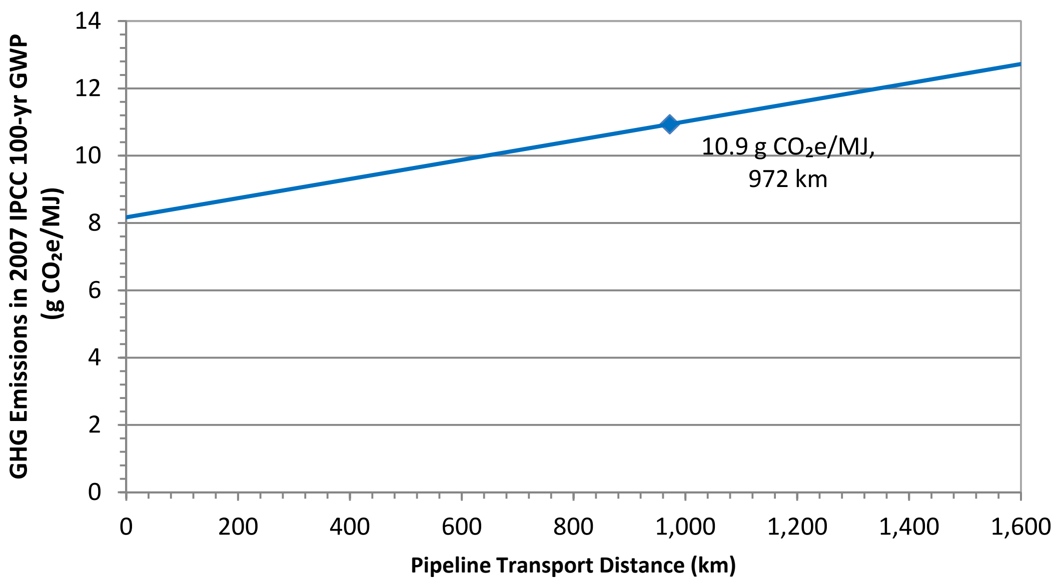
Figure 4-10: Sensitivity of Upstream Marcellus Shale NG GHGs to Parameter Changes



The above results show that both the onshore and shale profiles are sensitive to changes in pipeline distance, which is currently set to 972 km for all profiles. As more unconventional sources like Marcellus Shale, which is close to major demand centers (New York, Boston, Toronto), come on the market, the average distance natural gas has to travel will go down, decreasing the overall impact.

The pipeline transport of natural gas is inherently energy intensive because compressors are required to continuously alter the physical state of the natural gas in order to maintain adequate pipeline pressure. Further, the majority of compressors on the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline. **Figure 4-11** shows the sensitivity of natural gas losses to pipeline distance. The study default for domestic sources of natural gas is 972 km, which was determined by solving for the distance at which the per-mile emissions were equivalent to U.S. annual natural gas transmission methane emissions.

Figure 4-11: Sensitivity of GHG Results to Pipeline Distance



Marginal production is defined here as the next unit of natural gas produced not included in the average, presumably from a new, highly productive well for each type of natural gas. Since older, less productive wells are ignored as part of these results, the production rate per well is much higher, episodic emissions are spread across more produced gas, and the corresponding GHG inventory is lower. **Table 4-9** shows the production rate assumptions used for both the average and marginal cases.

Table 4-9: Production Rate Assumptions for Average & Marginal Cases[1]

Source	Well Count	Dry Production (Tcf)	Production Rate (Mcf/day)					
			Average			Marginal		
			Expected Value	Low (-30%)	High (+30%)	Expected Value	Low (-30%)	High (+30%)
Onshore	216,129	5.2	66	46	86	593	297	1,186
Offshore	2,641	2.7	2,801	1,961	3,641	6,179	3,090	12,358
Associated	31,712	1.4	121	85	157	399	200	798
Tight Gas	162,656	6.6	111	78	144	111	77	143
Barnett Shale	32,797	3.3	274	192	356	274	192	356
Marcellus Shale	N/A	N/A	335	479	623	335	479	623
CBM	47,165	1.8	105	73	136	105	73	136

The marginal and average production rates for the unconventional sources (tight, shales, and CBM) were identical, so there is no change shown below. There was a significant change in the production rate for all the mature conventional sources. Large numbers of the wells from each of these sources are nearing the end of the useful life, and have dramatically lower production rates, bringing the average far below what would be expected of a new well of each type.

Table 4-10: Average and Marginal Upstream Greenhouse Gas Emissions

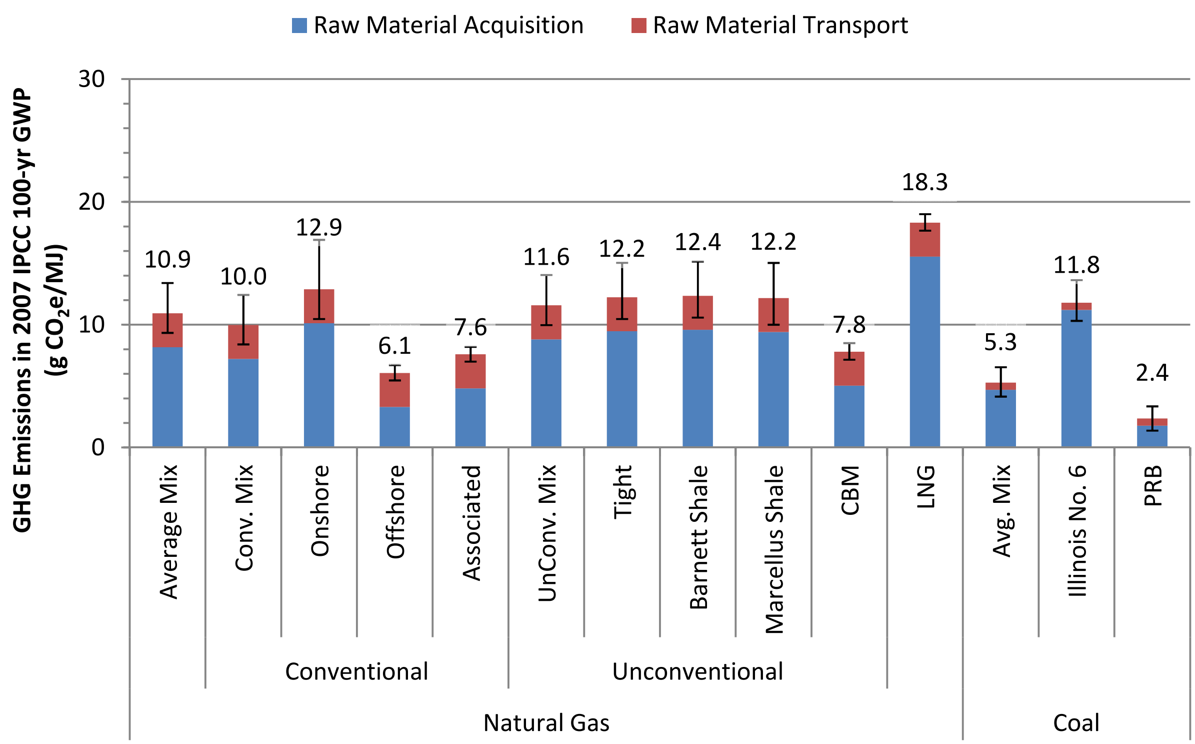
Source		Average	Marginal	Percent Change
		(g CO_2e/MJ)		
Conventional	Onshore	12.9	8.1	-37.1%
	Offshore	6.1	6.0	-1.6%
	Associated	7.6	7.5	-1.3%
Unconventional	Tight Gas	12.2	12.2	0.0%
	Barnett Shale	12.4	12.4	0.0%
	Marcellus Shale	12.2	12.2	0.0%
	Coal Bed Methane	7.8	7.8	0.0%
Liquefied Natural Gas		18.3	18.2	-0.5%

[1] The well count and dry production data are representative of the 2009 U.S. domestic natural gas supply, of which Marcellus Shale was a negligible contribution

Although the production rates for both associated gas and offshore gas change significantly, there is little change to the upstream value: a drop of 1.3 percent and 1.6 percent respectively. This has to do with the characteristics of these types of wells; the flow of natural gas in offshore wells is so strong that there is no need to periodically perform liquids unloading, and for associated wells, the petroleum co-product is constantly removing any liquid in the well. This means the only episodic emission (one which would need to be allocated by lifetime production of the well) is the construction or completion of the well, which is small in both cases, as a percentage of overall emissions. That leaves onshore conventional production as the only source which shows a significant difference (a drop of 37.1 percent) between the average and marginal production. There are over 200,000 active onshore conventional wells, over 80 percent of which have daily production below the average rate of 138 Mcf/day (EIA, 2010). Yet, when this marginal natural gas is run through electricity generation, there is less than a 5 percent drop in GHG emissions.

More insight can be gained by comparing the LC of natural gas power to those of coal. The upstream GHG emissions for various fuels are shown in **Figure 4-12**.

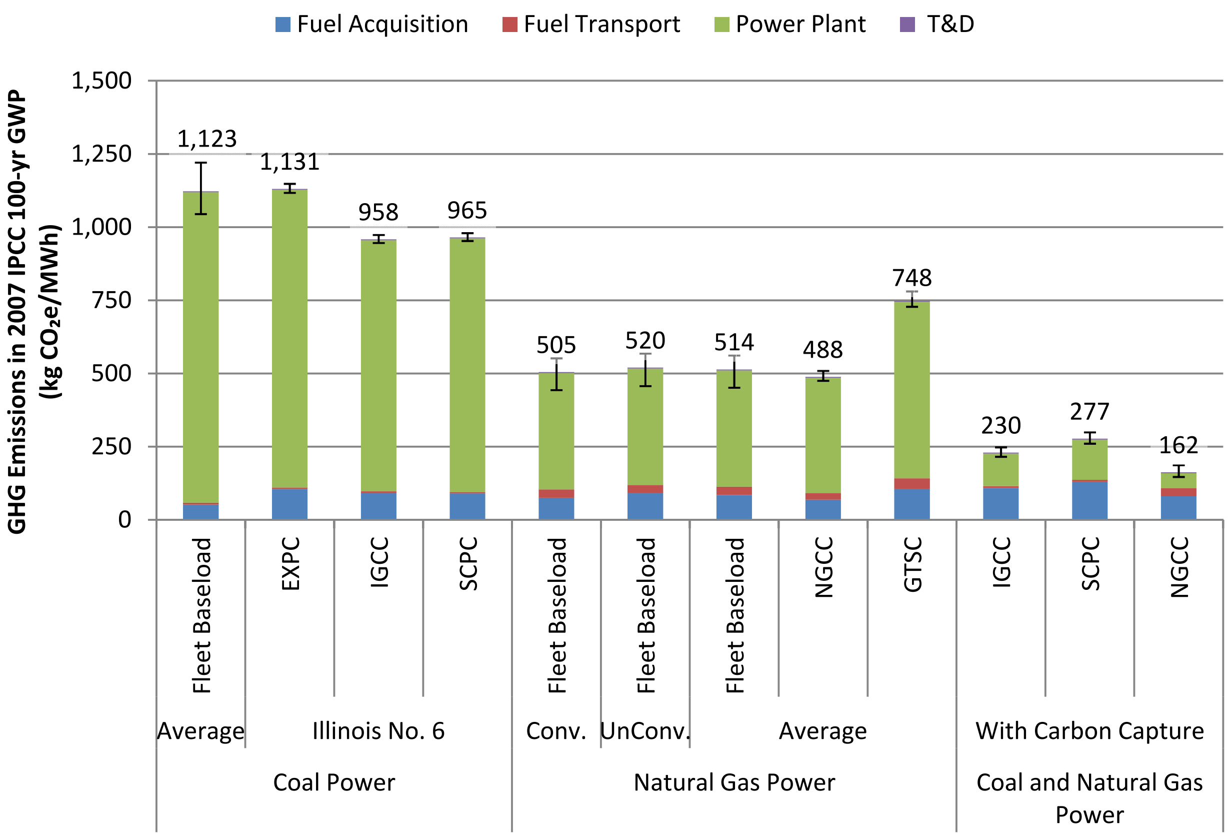
Figure 4-12: Comparison of Upstream GHG Emissions for Various Feedstocks



Compared on an upstream energy basis, natural gas has higher GHG emissions than coal does. Comparing the average mixes from **Figure 4-12**, the nominal GHG results for natural gas are more than 2 times greater than those for average coal (10.9 vs. 5.3 g CO_2e/MJ). Gassier bituminous coal, such as Illinois No. 6, is more comparable, but only makes up 31 percent of domestic consumption on an energy basis.

The per unit energy upstream emissions comparisons shown above are somewhat misleading in that a unit of coal and natural gas often provide different services. If they do provide the same service, they often do so with different efficiencies—it is more difficult to get useful energy out of coal than it is out of natural gas. To provide a common basis of comparison, different types of natural gas and coal are run through various power plants and converted to electricity. Note that there are alternative uses of both fuels and different bases on which they could be compared. However, in the U.S., the vast majority of coal is used for power production, so it provides the most relevant comparison. **Figure 4-13** compares results for natural gas and coal power on the basis of 1 MWh of electricity delivered to the consumer. In addition to the NETL baseline fossil plants with and without CCS, these results include a GTSC and representations of fleet average baseload coal and natural gas plants.

Figure 4-13: Life Cycle GHG Emissions for Electricity Generation



In contrast to the upstream results, which showed significantly higher GHGs for natural gas than coal, these results show that natural gas power, on a 100-year GWP basis, has a much lower impact than coal power without capture, even when using unconventional natural gas. When using less efficient simple cycle turbines, which provide peaking power to the grid, there are far fewer GHGs emitted than for coal-fired power. Because of the different roles played by these plants, the fairest comparison is the domestic mix of coal run through an average baseload coal power plant with the domestic mix of natural gas run through the average baseload natural gas plant. In that case, the coal-fired plant has emissions of 1,123 kg CO_2e/MWh, more than double the emissions of the natural-gas fired plant at 514 kg CO_2e/MWh. **Figure 4-14** shows the same results but applying and comparing 100- and 20-year IPCC global warming potentials to the inventoried GHGs.

Figure 4-14: LC GHG Emissions for Various Power Technologies by GWP

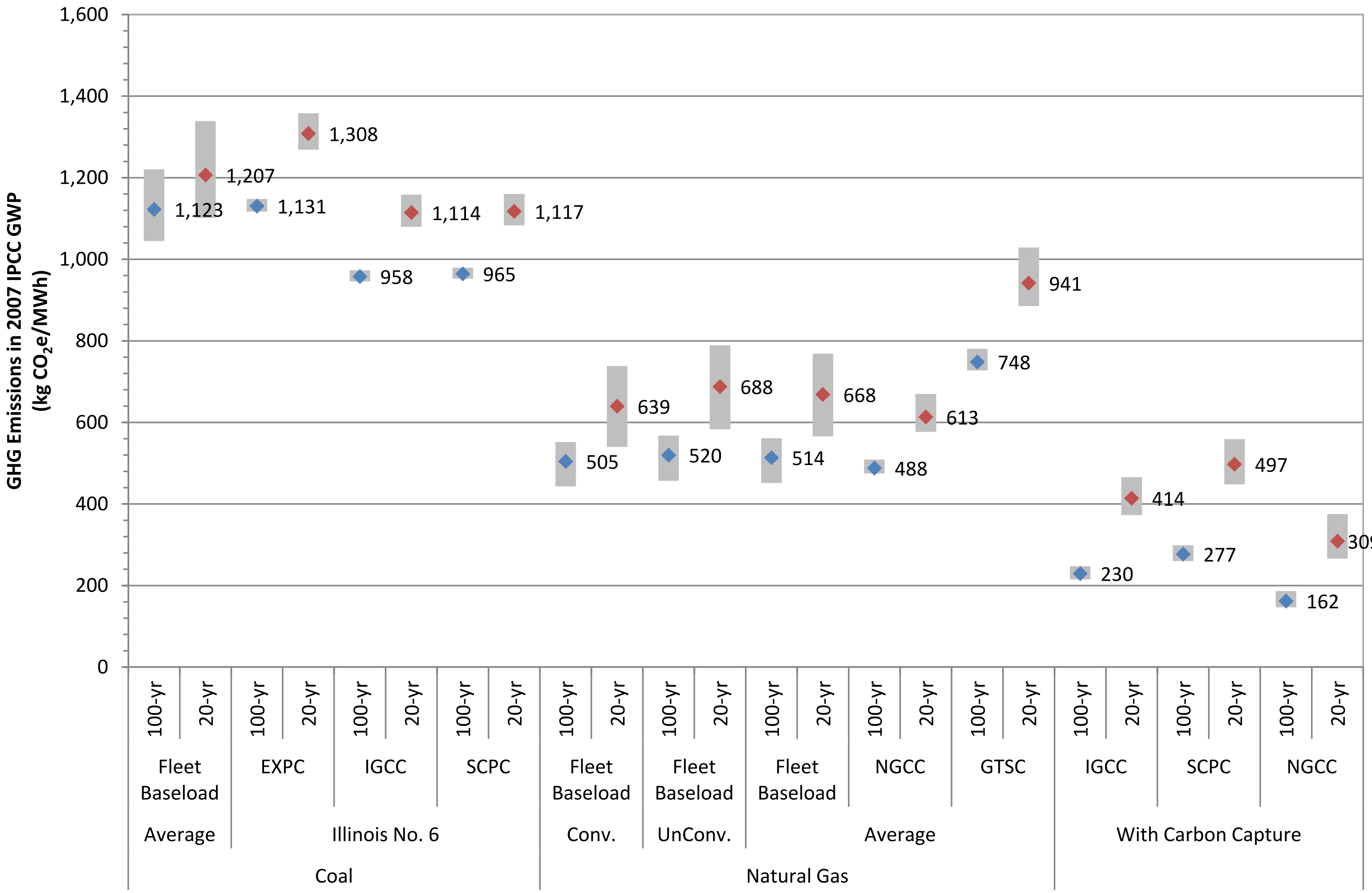


Figure 4-14 shows that even when using a GWP of 72 for CH_4 to increase the relative impact of upstream methane from natural gas, gas-fired power still has lower GHGs than coal-fired power. This conclusion holds across a range of fuel sources (conventional vs. unconventional for natural gas, bituminous vs. average for coal) and a range of power plants (GTSC, NGCC, average for natural gas, and IGCC, SCPC, EXPC, and average for coal). The one situation where this conclusion changed is the use of unconventional natural gas in an NGCC unit with carbon capture compared to an IGCC unit with carbon capture. The high end of the range overlaps the nominal value for IGCC in this situation.

4.8.2 GHG Emissions from Land Use

Results from the analysis of transformed land area based on NGCC power production are shown in **Figure 4-15**. Power from offshore natural gas has the lowest area of land use change; the land used by a natural gas pipeline and power plant are the only sources of land use burdens in the offshore natural gas supply chain. Using tight gas for NGCC power has the highest land use burdens, which is due to the lower per-well yields for tight gas in comparison to other natural gas sources. Gas extraction from Marcellus Shale results in the highest proportional loss of forest land, at approximately 72 percent of total transformed land area for that profile, due to a large proportion of forested area in the Marcellus Shale region. Conversely, Barnett Shale has the highest proportional loss of grassland, at approximately 56 percent of total transformed land area for Barnett Shale.

Figure 4-15: Direct Transformed Land Area for NGCC Power

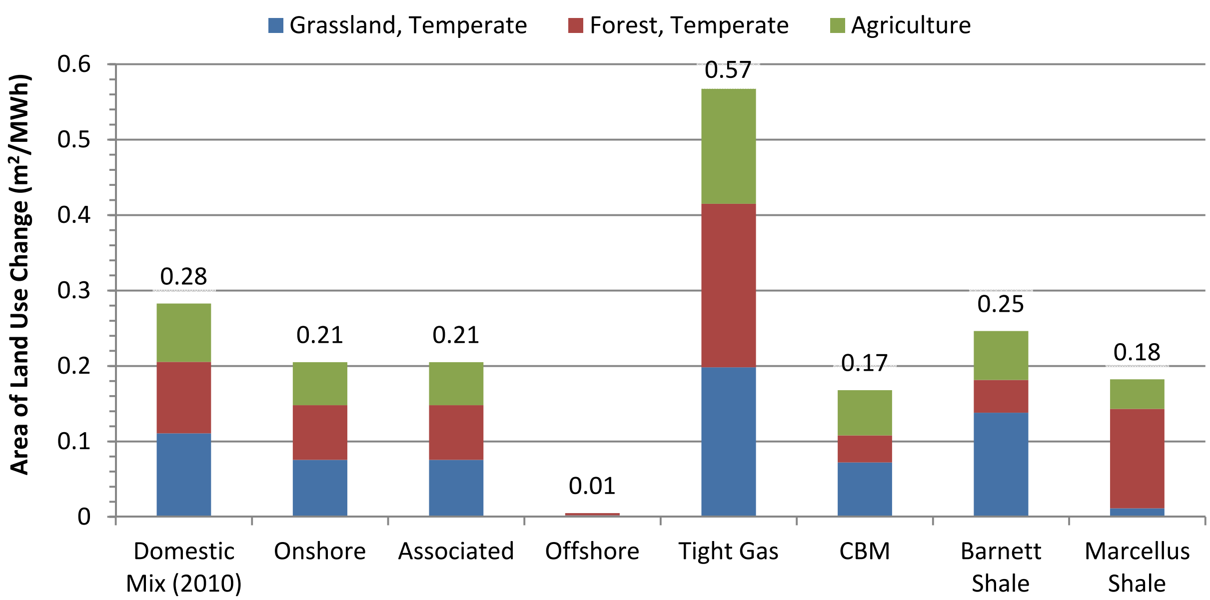
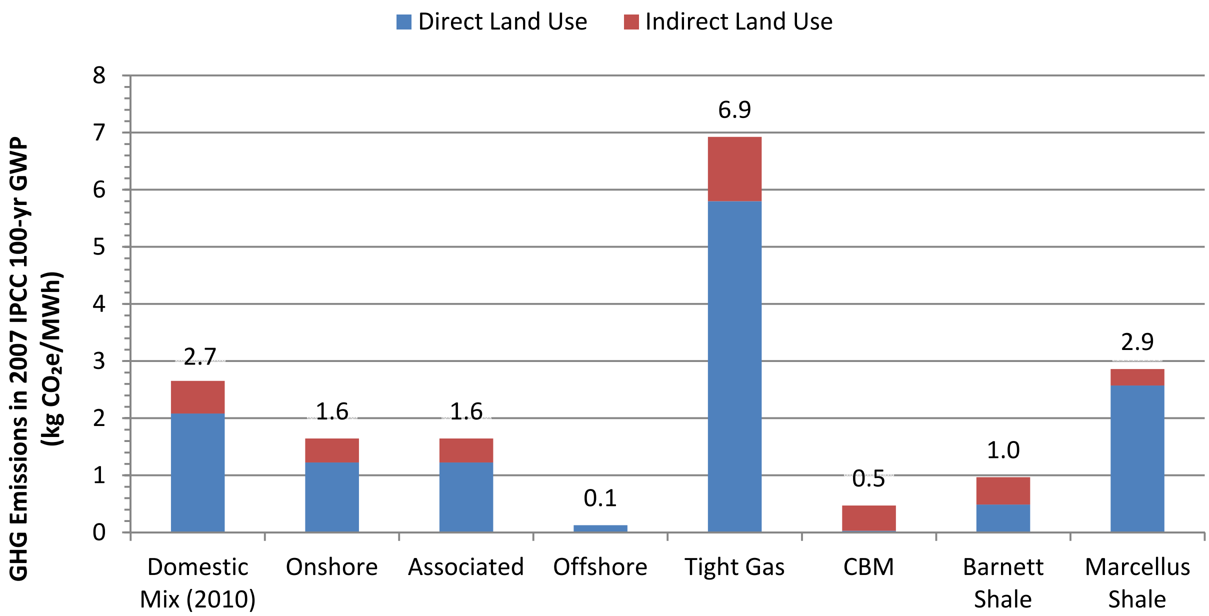


Figure 4-16 shows results from the analysis of GHG emissions from direct and indirect land use. Direct land use emissions comprise the majority of total land use GHG emissions with the exception of coal bed methane, which has a small direct land use footprint. When the domestic natural gas mix is used for NGCC power (without CCS), the GHG emissions from land use change are 2.7 kg CO_2e/MWh, which is only 0.6% of the other GHG emissions (488 kg CO_2e/MWh) from the life cycle of NGCC power. The land use GHG emissions from individual natural gas sources (when run through NGCC power) range from 0.1 kg CO_2e/MWh for offshore natural gas to 6.9 kg CO_2e/MWh

for tight gas when run through NGCC power (without CCS). Tight-gas land use GHG emissions exceed all other natural gas profiles due to their higher per MWh transformed land area, as discussed previously.

The trends in GHG emissions from different gas sources in **Figure 4-16** are consistent with the trends shown in **Figure 4-15**, except for the results for the two types of shale gas. Generally speaking, changes to forest land result in relatively high direct land use emissions because aboveground forest biomass stores higher levels of carbon than other land types. Further, indirect land use GHG emissions are driven solely be lost agricultural land. Therefore, the Barnett Shale result is comprised of a relatively high proportion of indirect GHG emissions from agriculture loss, combined with a relatively low proportion of direct GHG emissions from forest loss. Conversely, the Marcellus Shale result shows relatively high land use GHG emissions from direct changes to forests, and relatively low land uses GHG emissions from indirect changes to agriculture.

Figure 4-16: Direct & Indirect Land Use GHG Emissions for NGCC Power



The above land use results are on the basis of NGCC power. The GHG emissions from land use scale directly with the heat rate of the associated natural gas power plant. The heat rate of NGCC with CCS is 17 percent higher than for NGCC, so all GHG emissions from land use are 17 percent higher for NGCC with CCS. Similarly, all GHG emissions from land use are 67 percent higher for GTSC power (compared to NGCC).

4.8.3 Non-GHG Emissions

Non-GHG emissions include CO and NO_X, which arise from the combustion of fuels (natural gas, diesel, and heavy fuel oil) by the primary activities throughout LC Stages #1, #2, and #3 as well as by secondary fuel and material production activities. SO_2 emissions arise from the combustion of diesel and heavy fuel oil in LC Stages #1 and #2, as well as from the secondary production of electricity used by the pipeline operations of Stage #2. NH_3 emissions result from liquefaction (Stage #1 for imported natural gas) and NGCC plant operations. Lead (Pb) and Hg emissions do not represent a significant contribution to the LC emissions of any of the scenarios of this analysis and are highly concentrated in construction activities.

Each source of natural gas has unique construction and extraction requirements, which results in different emission profiles for criteria air pollutants and other non-GHG emissions. The following table shows the upstream emissions, RMA and RMT, for each type of natural gas. The RMT emission profile is identical for all types of natural gas because the same transport distance (971 km) is modeled for each type of natural gas.

Table 4-11: Upstream Non-GHG Emissions

LC Stage	Emission (g/MJ)	Mix (2010)	Onshore	Associated	Offshore	Tight Gas	CBM	Barnett Shale	Marcellus Shale
Raw Material Acquisition (RMA)	Pb	2.37E-07	3.38E-07	1.39E-07	1.07E-08	2.55E-07	4.24E-07	1.66E-07	2.14E-07
	Hg	8.12E-09	9.27E-09	3.81E-09	2.95E-10	6.99E-09	1.16E-08	1.49E-08	7.13E-09
	NH_3	1.07E-07	5.64E-08	2.34E-08	7.70E-09	4.27E-08	7.08E-08	4.55E-07	1.15E-07
	CO	5.24E-03	6.37E-03	5.73E-03	5.05E-04	6.10E-03	6.65E-03	4.60E-03	6.05E-03
	NO_X	5.79E-02	6.93E-02	6.85E-02	2.06E-03	6.90E-02	6.96E-02	5.26E-02	6.91E-02
	SO_2	6.03E-04	4.46E-04	1.89E-04	6.83E-05	3.39E-04	5.58E-04	2.03E-03	5.27E-04
	VOC	5.62E-02	7.26E-02	2.12E-02	5.38E-03	7.27E-02	2.16E-02	7.26E-02	6.93E-02
	PM	5.74E-04	7.65E-04	4.13E-04	1.21E-04	6.18E-04	9.19E-04	4.35E-04	5.55E-04
Raw Material Transport (RMT)	Pb	1.97E-08	1.97E-08	1.97E-08	1.97E-08	1.97E-08	1.97E-08	1.97E-08	1.97E-08
	Hg	6.17E-10	6.17E-10	6.17E-10	6.17E-10	6.17E-10	6.17E-10	6.17E-10	6.17E-10
	NH_3	2.38E-07	2.38E-07	2.38E-07	2.38E-07	2.38E-07	2.38E-07	2.38E-07	2.38E-07
	CO	7.45E-05	7.45E-05	7.45E-05	7.45E-05	7.45E-05	7.45E-05	7.45E-05	7.45E-05
	NO_X	9.32E-05	9.32E-05	9.32E-05	9.32E-05	9.32E-05	9.32E-05	9.32E-05	9.32E-05
	SO_2	3.79E-05	3.79E-05	3.79E-05	3.79E-05	3.79E-05	3.79E-05	3.79E-05	3.79E-05
	VOC	1.90E-06	1.90E-06	1.90E-06	1.90E-06	1.90E-06	1.90E-06	1.90E-06	1.90E-06
	PM	7.82E-06	7.82E-06	7.82E-06	7.82E-06	7.82E-06	7.82E-06	7.82E-06	7.82E-06
Cradle to Gate (RMA + RMT)	Pb	2.57E-07	3.57E-07	1.59E-07	3.05E-08	2.74E-07	4.44E-07	1.86E-07	2.34E-07
	Hg	8.74E-09	9.88E-09	4.43E-09	9.13E-10	7.61E-09	1.23E-08	1.56E-08	7.74E-09
	NH_3	3.45E-07	2.94E-07	2.61E-07	2.45E-07	2.80E-07	3.09E-07	6.93E-07	3.53E-07
	CO	5.31E-03	6.44E-03	5.81E-03	5.80E-04	6.18E-03	6.72E-03	4.68E-03	6.12E-03
	NO_X	5.80E-02	6.94E-02	6.86E-02	2.15E-03	6.91E-02	6.97E-02	5.27E-02	6.92E-02
	SO_2	6.41E-04	4.84E-04	2.27E-04	1.06E-04	3.77E-04	5.96E-04	2.07E-03	5.65E-04
	VOC	5.62E-02	7.26E-02	2.12E-02	5.38E-03	7.27E-02	2.16E-02	7.26E-02	6.93E-02
	PM	5.82E-04	7.73E-04	4.21E-04	1.29E-04	6.26E-04	9.26E-04	4.43E-04	5.63E-04

In general, the construction and operation activities for natural gas acquisition (RMA) are greater than those from pipeline transport (RMT). Further, there is an inverse relationship between the production rate of a well and the non-GHG emissions. The material requirements and diesel combustion emissions associated with well construction are key sources of heavy metal and particulate emissions, so these emissions are minimized if wells have high lifetime recovery rates of natural gas.

The following figures illustrate the results RMA and RMT results for CO and NO_X data and demonstrate the variability in upstream, non-GHG emissions. **Figure 4-17** shows the upstream CO emissions for natural gas, and **Figure 4-18** shows the upstream NO_X emissions for natural gas.

Figure 4-17: Upstream CO Emissions for Natural Gas

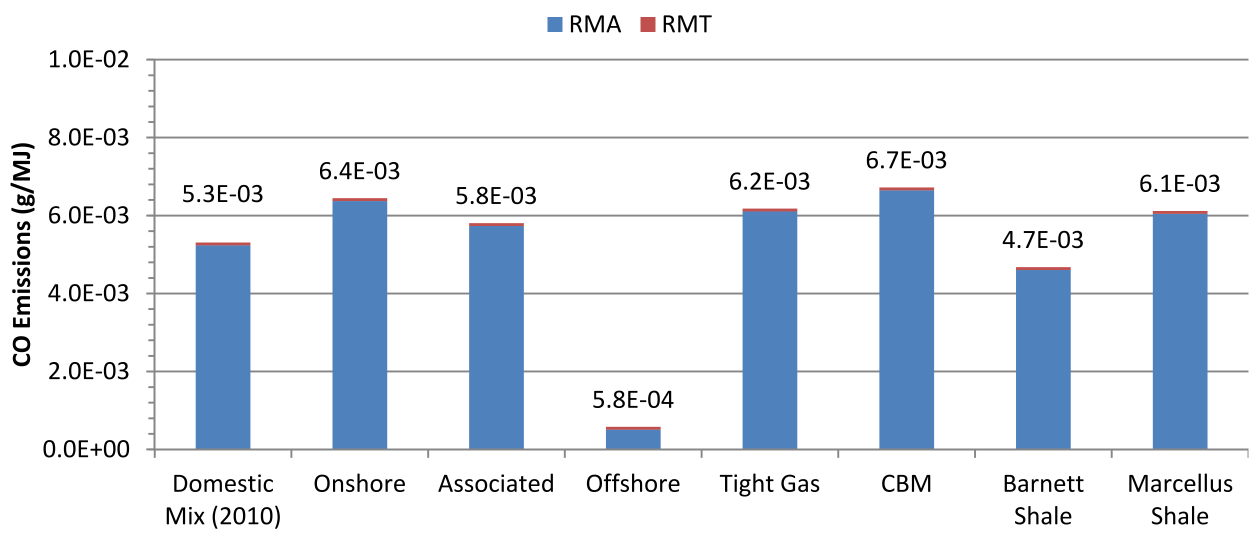
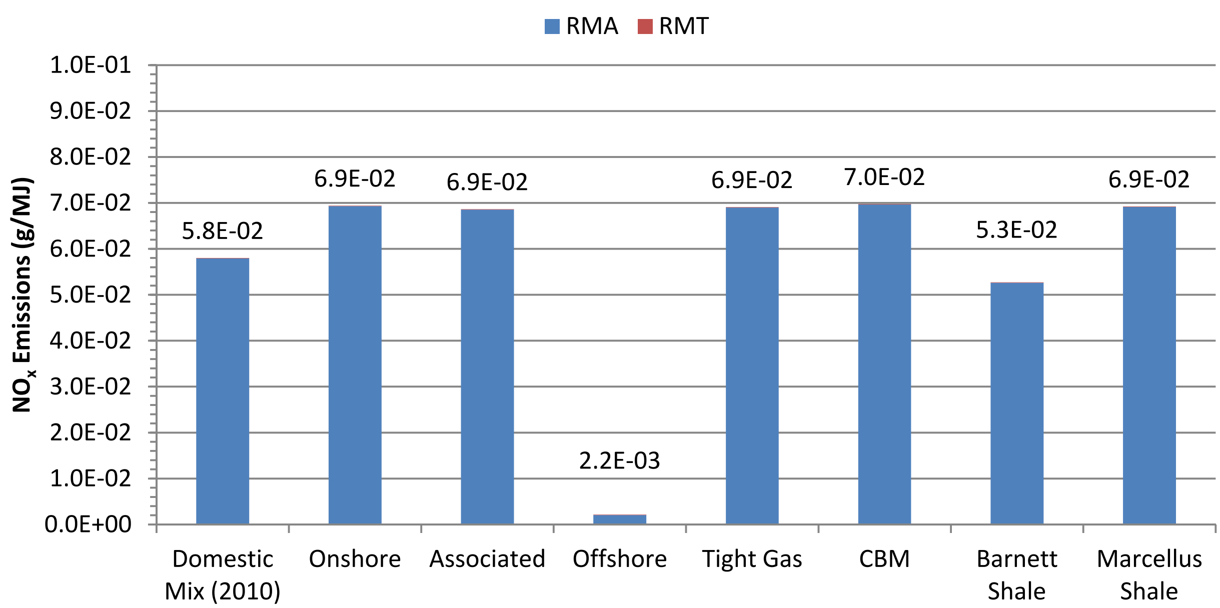


Figure 4-18: Upstream NO_X Emissions for Natural Gas



The above results focus on the upstream profile of natural gas types, but a life cycle perspective is necessary to evaluate upstream (RMA+RMT) emissions in comparison to emissions from the natural gas power plants (ECF). Using the 2010 domestic mix of natural gas, **Table 4-12** shows the life cycle results for non-GHG emissions using the functional unit of 1 MWh of delivered electricity.

Table 4-12: LC Non-GHG Emissions for Natural Gas Power Using Domestic NG Mix

Technology	Emissions (kg/MWh)	RMA	RMT	ECF	Total
NGCC	Pb	1.98E-06	1.65E-07	2.71E-06	4.86E-06
	Hg	6.80E-08	5.17E-09	2.46E-08	9.77E-08
	NH_3	8.98E-07	1.99E-06	1.88E-02	1.88E-02
	CO	4.38E-02	6.23E-04	3.12E-03	4.76E-02
	NO_X	4.85E-01	7.80E-04	3.05E-02	5.16E-01
	SO_2	5.06E-03	3.18E-04	1.19E-03	6.56E-03
	VOC	4.73E-01	1.59E-05	3.72E-05	4.73E-01
	PM	4.80E-03	6.55E-05	2.17E-03	7.04E-03
NGCC/ccs	Pb	2.32E-06	1.94E-07	3.09E-06	5.61E-06
	Hg	7.97E-08	6.06E-09	3.50E-08	1.21E-07
	NH_3	1.05E-06	2.33E-06	2.03E-02	2.03E-02
	CO	5.14E-02	7.31E-04	4.50E-03	5.66E-02
	NO_X	5.68E-01	9.14E-04	3.42E-02	6.03E-01
	SO_2	5.93E-03	3.72E-04	1.67E-03	7.97E-03
	VOC	5.55E-01	1.86E-05	4.74E-05	5.55E-01
	PM	5.63E-03	7.67E-05	2.47E-03	8.18E-03
GTSC	Pb	3.05E-06	2.55E-07	6.27E-07	3.94E-06
	Hg	1.05E-07	7.96E-09	7.08E-09	1.20E-07
	NH_3	1.38E-06	3.07E-06	2.90E-02	2.90E-02
	CO	6.75E-02	9.61E-04	5.48E-03	7.40E-02
	NO_X	7.47E-01	1.20E-03	4.87E-02	7.97E-01
	SO_2	7.79E-03	4.89E-04	1.53E-03	9.81E-03
	VOC	7.29E-01	2.45E-05	1.64E-04	7.30E-01
	PM	7.40E-03	1.01E-04	2.75E-03	1.03E-02

The following figures show the life cycle profiles for CO and NO_X for each energy conversion technology. **Figure 4-19** shows the life cycle emissions of CO, and **Figure 4-20** shows the life cycle emissions of NO_X.

Figure 4-19: LC CO Emissions for Natural Gas Power Using Domestic NG Mix

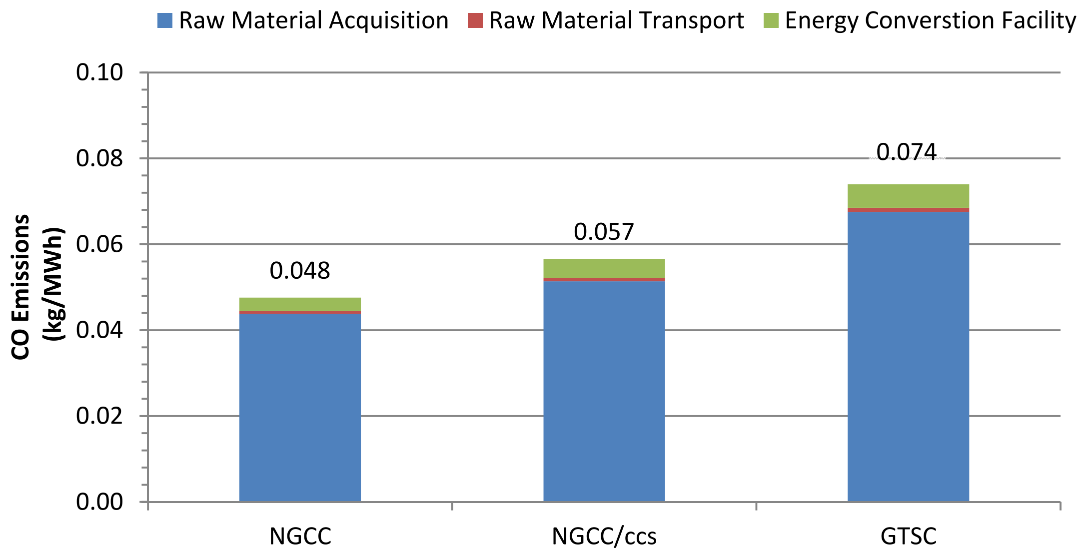
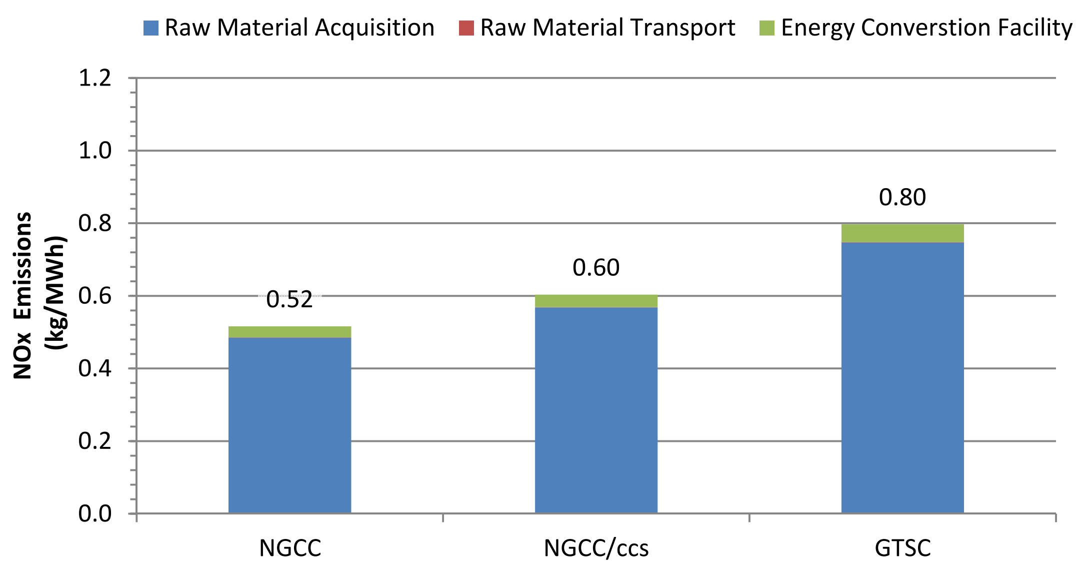


Figure 4-20: LC NO_X Emissions for Natural Gas Power Using Domestic NG Mix



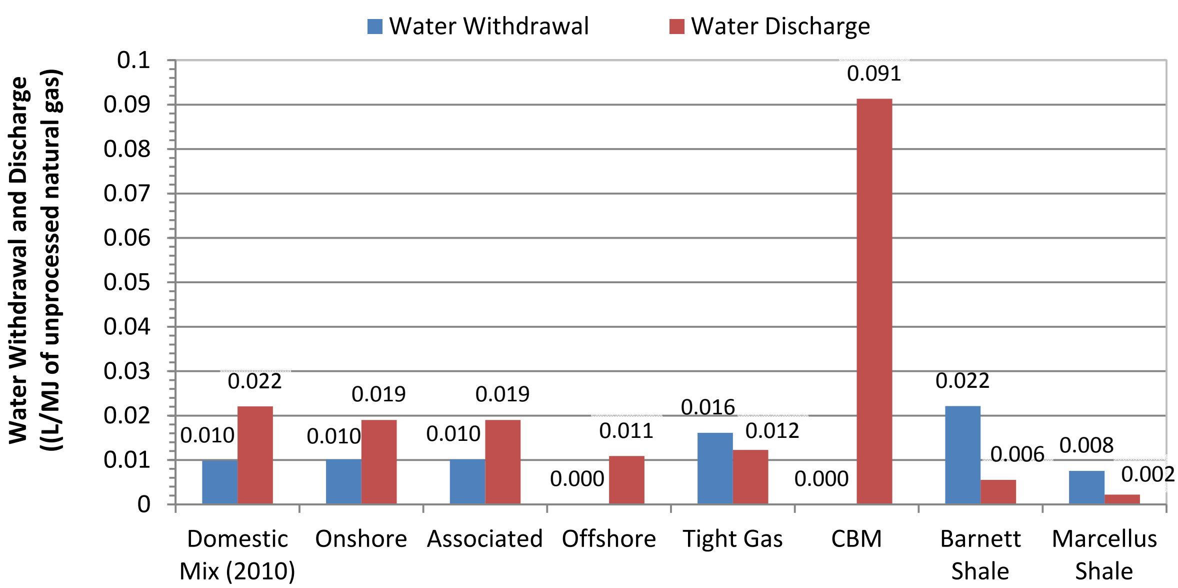
In general, the life cycle emissions increase with decreased power plant efficiency. The addition of CCS does not result in a significant change to the non-GHG emissions. The slightly higher non-GHG emissions from the CCS cases are due to the normalization of the LC results to the functional unit of 1 MWh of delivered electricity (due to the decreased NGCC efficiency caused by the CCS system, more natural gas is combusted by the CCS cases than the cases that do not have CCS).

4.8.4 Water Use

This analysis accounts for the volume of water withdrawn for natural gas extraction and the volume of water discharged from natural gas wells. The net difference between these two flows (withdrawal minus discharge) is the water consumption rate.

This analysis also translates the water flows to the basis of natural gas produced, so that if a well has a high production rate, it is possible for that well to have relatively low water use results per unit of production even if the water use rate during completion was relatively high. In other words, a high production rate during the life of a well can offset its high burdens during well completion. **Figure 4-21** provides a comparison of water withdrawal and discharge. In this case, the discharged water includes water that occurs naturally in the well formation (known as produced water) as well as flowback water that represents recovery of water used for hydrofracking. On the basis of natural gas produced, Marcellus Shale uses less water than Barnett Shale, conventional onshore, conventional onshore associated gas, and the 2010 U.S. domestic natural gas profile mix, but uses more water than conventional offshore and coal bed methane, where water is either not required or is reused from other available produced water. Tight gas water use, produced water, and net water consumption were estimated based on a 1:1 average of Barnett Shale water use and conventional onshore water use; this estimate was made due to lack of sufficient, readily available data and is noted as a data limitation.

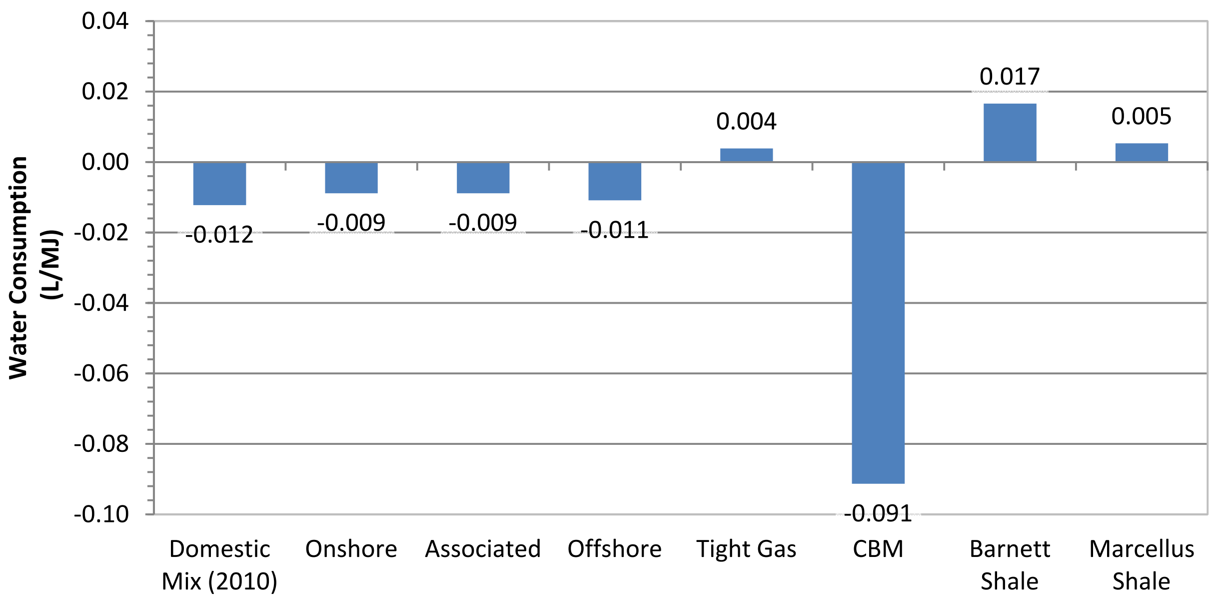
Figure 4-21: Upstream Water Use and Flowback Water Production for Natural Gas



Typical CBM wells are installed into relatively shallow coal formations, where a high water table is present. To enable natural gas extraction, the formation water is first pumped out of the coal seam. That formation water is typically discharged to the surface, and in cases where water quality is sufficient, may be put to beneficial use, such as for stock watering or supplemental agricultural water. Natural gas production increases as the water is drawn down, and methane is released from the formation. Thus, CBM RMA results in a considerable rate of water production.

Figure 4-22 provides a comparison of upstream water consumption for various types of natural gas. In terms of net water consumed, Marcellus Shale ranks second highest at 0.005 L/MJ, behind Barnett Shale (0.017 L/MJ). Net water consumption is reduced for conventional onshore and associated gas due to discharges of produced water to surface water. CBM does not consume water, but results in the production of water at a rate of approximately 0.091 L/MJ.

Figure 4-22: Net Upstream Water Consumption for Natural Gas



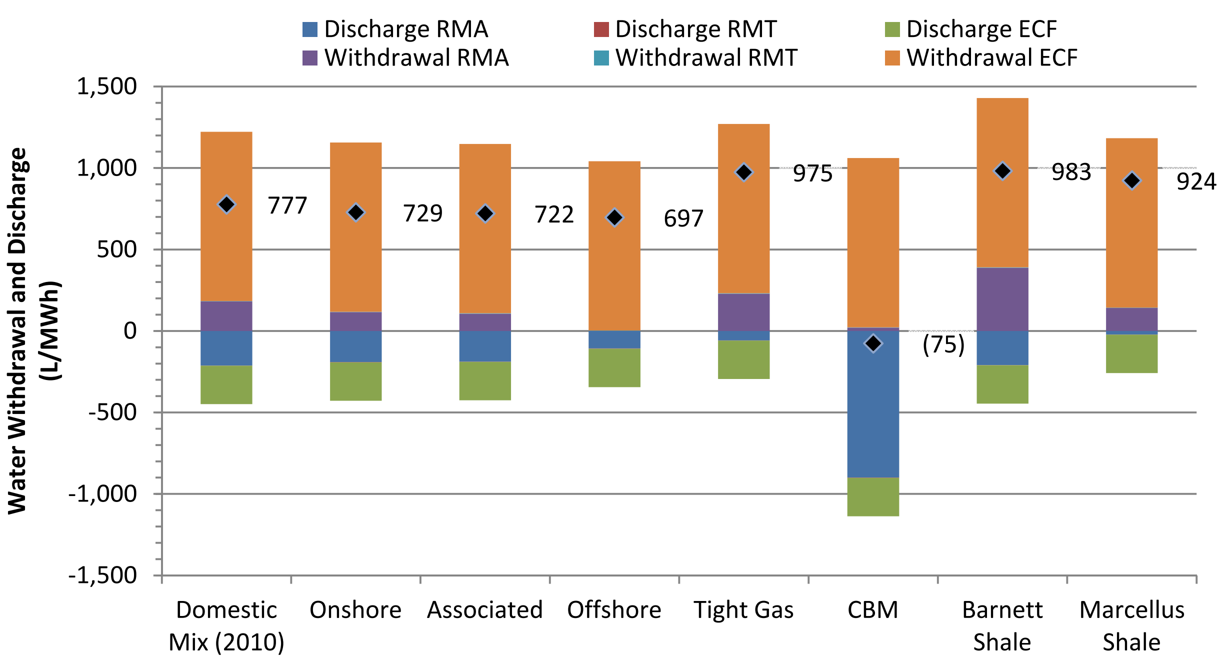
Water is an input to hydrofracking, which is used for recovering natural gas from tight reservoirs such as Barnett Shale and Marcellus Shale. The water inputs for the completion of a horizontal, shale-gas well ranges from 2 to 4 million gallons. The variability in this value is due to basin and formation characteristics (GWPC & ALL, 2009). The completion of shale gas wells in the Barnett shale gas play uses 1.2 and 2.7 million gallons of water for vertical and horizontal wells, respectively. The data used in the LCA model of this analysis is based on the water use and natural gas production of the entire Barnett Shale region, so it is a composite of vertical and horizontal wells and has a per well average water use of 2.3 million gallons (8.7 million L). The completion of a horizontal well in the Marcellus Shale gas play uses 3.9 million gallons (15 million L) of water (GWPC & ALL, 2009). Water used for hydrofracking accounts for 98 percent of this water use; the remaining 2 percent accounts for water used during well drilling. As stated above, this analysis translates water flows to the basis of natural gas produced, so that if a well has a high production rate, it is possible for that well to have lower water-use results per unit of gas production even if the water-use rate during completion is higher than other type of wells. This is demonstrated by the shale gas results in **Figure 4-22**; Marcellus Shale has higher water consumption than Barnett Shale per completed well (15 vs. 8.7 million L), but lower water consumption than Barnett Shale per unit of natural gas produced (0.005 vs. 0.017 L/MJ).

The results for water withdrawal and consumption should be viewed from an LC perspective, beginning with natural gas extraction and ending with electricity delivered to the consumer. The LC water withdrawal and discharge for natural gas power from seven sources of natural gas are shown in **Figure 4-23**. This figure is based on a functional unit of 1 MWh of delivered electricity, is representative of an NGCC power plant (without CCS), and accounts for a 7 percent T&D loss between the power plant and consumer. Water withdrawals are shown as positive values, discharges are shown as negative values, and net consumption is shown by the black diamond on each data series.

As shown by **Figure 4-23** on the basis of 1 MWh of delivered electricity, the magnitude of water withdrawals and discharges is greatest for the energy conversion facility for all natural gas profiles considered. Net water consumption varies considerably based on the natural gas source that is considered. Net water consumption rates for conventional onshore (729 L/MWh), conventional offshore (697 L/MWh), and onshore associated natural gas (722 L/MWh) are essentially similar in terms of net water consumption. However, due to elevated water requirements for hydrofracking, water consumption for the shale and tight gas sources is elevated. For instance, in comparison to conventional onshore natural gas production (729 L/MWh), tight gas requires 34 percent more water (975 L/MWh), Marcellus Shale requires 27 percent more water (924 L/MWh), and Barnett Shale requires 35 percent more water (983 L/MWh).

The acquisition of CBM natural gas does not consume water. As discussed above, CBM extraction involves the removal of naturally occurring water from the formation. The life cycle of an NGCC system using natural gas from CBM results in more water discharges than withdrawals.

Figure 4-23: LC Water Withdrawal & Discharge for NGCC Power Using Various Sources of NG



The LC water consumed by the cases with CCS is approximately 1.8 times higher than the LC water consumed by the cases without CCS. This difference is due to the water requirements of the CCS system, associated with increased cooling requirements. The Econamine FG Plus℠ process requires cooling water to reduce the flue gas temperature from 57°C to 32°C, cool the solvent (the reaction between CO_2 and the amine solvent is exothermic), remove the heat input from the additional auxiliary loads, and remove the heat in the CO_2 compressor intercoolers (NETL, 2007; Reddy, Johnson, & Gilmartin, 2008). The NGCC case without CCS consumed 80 percent of water input while the case with CCS consumed 79 percent.

4.8.5 Water Quality

This analysis accounts for the water quality constituents associated with discharge water. These constituents have the potential to degrade surface or shallow groundwater quality. This analysis does not consider changes to water quality in deep aquifers, or the potential for migration of deep aquifer water to shallow aquifers used for potable water supply.

Water quality data for each of the natural gas types are not available from a single data source, but from a variety of sources. The water quality data available for Marcellus Shale were more detailed than any of the other natural gas profiles. As a result, only select water quality constituents can be meaningfully compared across all of the natural gas types. The water quality constituents considered here are described in terms of mass loadings: that is, the total mass of a water quality constituent, measured without the water in which it is contained, per unit of natural gas extracted. **Figure 4-23** provides a comparison of total dissolved solids (TDS) loading for each natural gas profile. The TDS parameter is a measurement of the total inorganic and organic constituents that are not removed by a 2 µm filter. In produced water systems, TDS typically contains primarily ionic minerals (salts), but may also contain organic material and other constituents. TDS is analogous to salinity, although the term 'salinity' is typically restricted to the concentration of dissolved minerals contained in ocean water. TDS is a useful parameter for broadly comparing water quality since it integrates a wide array of minerals and other substances that may be contained in a water sample. Elevated TDS levels can also deleteriously affect the taste of potable water, reduce agricultural crop yields, and contribute to regional salt loadings, in some cases reducing the potential for beneficial use of affected waters. The U.S. EPA maintains a secondary maximum contaminant level (MCL) water quality standard for drinking water of 0.5 g/L. For comparison, seawater averages around 32 g/L, and some produced waters can reach 100 g/L or more.

TDS emissions associated with natural gas production are a result of the disposal or release of various produced water, including flowback water and wastewater that is treated on site or through wastewater treatment plants, including municipal wastewater treatment plants (WWTP). Ionic salts, the primary constituents of TDS, are extremely difficult and costly to remove during water treatment. For Marcellus Shale production, where flowback waters are often routed through municipal wastewater systems, municipal wastewater treatment plants do not maintain sufficient treatment facilities to measurably reduce TDS loads during treatment. Thus, essentially all of the TDS that is discharged from flowback water to a municipal WWTP is later released to surface waters.

As shown in **Figure 4-24**, Barnett Shale, conventional onshore, onshore associated, and tight gas production result in about 6E-05 kg of TDS per MJ of natural gas. Marcellus Shale is slightly higher, at approximately 8E-05 kg of TDS per MJ of natural gas. CBM wells result in very high loading rates in part because suitable coal layers in the U.S. Rocky Mountain states (where most CBM is produced) contain water with high TDS levels. Additionally, the operation of CBM wells generates large volumes of produced water, which translates to high TDS loadings. High TDS is less problematic for water quality at offshore wells, where produced water having relatively high TDS loads is typically discharged to the ocean without treatment for TDS.

Figure 4-25 shows composite values for organics, including oil and grease as well as total and dissolved organic carbon. Note that sufficient data were not available to calculate values for CBM or Barnett Shale. Also note that data quality is somewhat lower for organics as compared to TDS;

however, some meaningful comparisons can still be made. For instance, Marcellus Shale production results in about the same (or perhaps slightly lower) emissions of organic constituents, in comparison to conventional onshore and associated natural gas. Conventional offshore gas extraction results in substantially higher emission rates for organics.

Figure 4-24: Upstream Total Dissolved Solid Loads

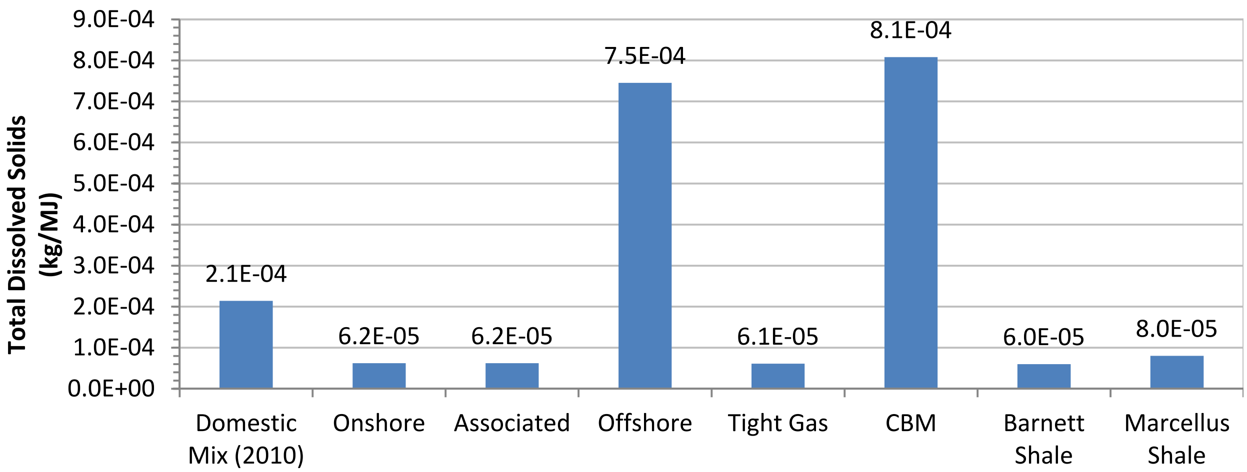
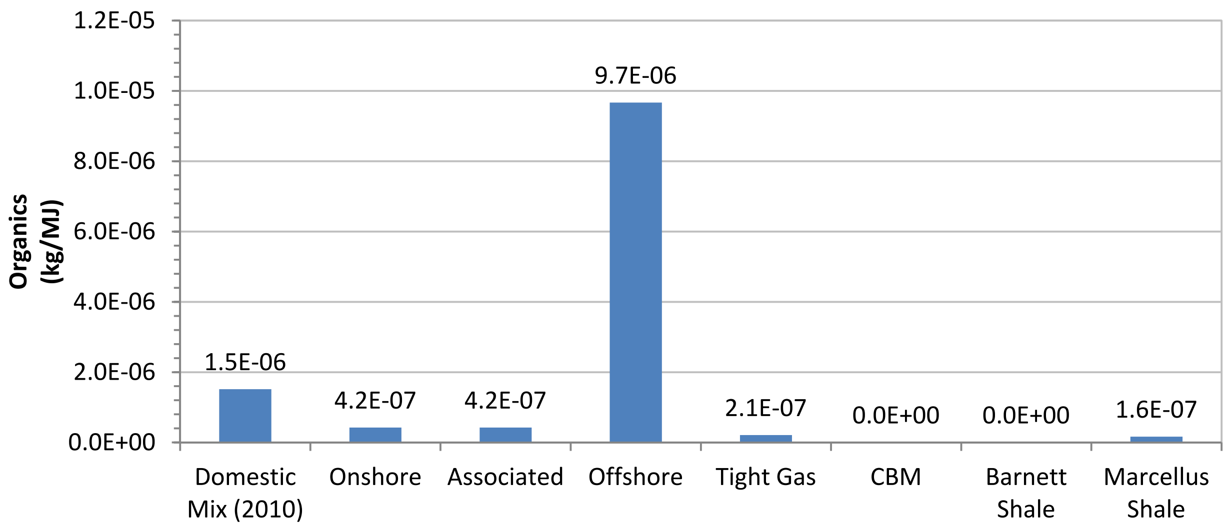


Figure 4-25: Organics Loads for Natural Gas Extraction



The highest rate of TDS loading, per unit of natural gas production, was indicated for CBM, due largely to the large volumes of TDS containing water that are produced by CBM extraction. Emission of organics to water was much higher for conventional offshore production than all other natural gas sources.

4.8.6 Energy Return on Investment (EROI)

The energy return on investment (EROI) is the ratio of energy produced to total energy expended. The functional unit of this LCA is 1 MWh of delivered electricity and represents the amount of energy produced by the system. The total energy expended is the energy content of all resources (crude oil, coals, natural gas, uranium, and renewable resources) that enter the life cycle boundaries minus the useful energy in the final product (the functional unit).

EROI calculations are often applied to the life cycle of a primary fuels. For example, if the energy expended on the extraction, processing, and transport of a fuel is 10 percent of the useful energy in the fuel, the EROI can be expressed as a ratio of 10:1. In addition to the extraction and delivery of primary fuels, the boundaries of this analysis include the conversion of primary energy to electrical energy. The EROI for electric power systems is less than one because the conversion of thermal energy to electric energy expends more than half of the energy content of the energy that enters the power plant. For example, if a power plant has an overall efficiency of 33 percent, 67 percent of the energy entering the power plant is expended.

The NGCC power plant is the most efficient energy conversion facility of this analysis, so it has the highest EROI (0.6:1) of this analysis. The supply chain for natural gas does not require significant inputs of other energy resources, so the resource energy of natural gas accounts for over 99 percent of total resource energy for all power cases in this analysis. The EROIs of four natural gas power systems using the 2010 domestic mix of natural gas are shown **Table 4-13**.

Table 4-13: EROI for Natural Gas Power Systems

Resource	NGCC	NGCC/ccs	GTSC	Fleet Average NG Power
Useful Energy Produced, MJ	**1.0**	**1.0**	**1.0**	**1.0**
Total System Energy Input, MJ	**2.6**	**3.1**	**4.1**	**3.2**
Crude oil, MJ	<0.1	<0.1	<0.1	<0.1
Hard coal, MJ	<0.1	<0.1	<0.1	<0.1
Lignite, MJ	<0.1	<0.1	<0.1	<0.1
Natural gas, MJ	2.6	3.1	4.1	3.2
Uranium, MJ	<0.1	<0.1	<0.1	<0.1
Renewables	<0.1	<0.1	<0.1	<0.1
Total Energy Expended, MJ	**1.6**	**2.1**	**3.1**	**2.2**
EROI	**0.6:1**	**0.5:1**	**0.3:1**	**0.4:1**

If EROI is calculated only around the boundaries of raw material extraction and raw material transport, the EROI of domestic natural gas (using the 2010 supply mix) is 7.6. This value represents the useful thermal energy in delivered gas divided by the energy expended during its acquisition and transport. The data used for calculating this upstream natural gas EROI are shown in **Table 4-14**.

Table 4-14: EROI for Upstream Natural Gas (2010 Domestic Mix)

Resource	Total (RMA + RMT)
Useful Energy Produced, MJ	**1.0**
Total System Energy Input, MJ	1.1
Crude oil, MJ	<0.01
Hard coal, MJ	<0.01
Lignite, MJ	<0.01
Natural gas, MJ	1.1
Uranium, MJ	<0.01
Renewables	<0.01
Total Energy Expended, MJ	**0.1**
EROI[1]	**7.6:1**

[1] The EROI implied by this table is higher (10:1) than the calculated EROI (7.6:1) due to rounding of energy inputs that are less than 0.01 MJ.

5 Cost Analysis of Natural Gas Power

The following cost analysis provides an overview of the natural gas market including demand, supply, and price volatility. The capital and O&M costs are used to calculate the COE from a life cycle perspective.

5.1 Natural Gas Market

The natural gas industry uses a variety of extraction technologies and has varying scales of production depending on specific characteristics of a natural gas source, extraction technology, and formation capacity. Therefore, it is likely that the cost of extracting a unit of natural gas varies from well to well. However, natural gas is a commodity, and thus the price paid by consumers is not a function of individual well characteristics, but is driven by overall market forces. Natural gas is a commodity for two reasons. First, the dehydration and acid removal operations for natural gas processing allow producers to improve the quality of raw natural gas so that it meets pipeline specifications, so all pipeline natural gas, regardless of its origin, has similar composition and heating properties. Second, the U.S. has an extensive pipeline network for natural gas transmission that connects all established domestic sources with markets.

An understanding of the overall natural gas market provides more information on the price of natural gas than a focus on the costs of specific extraction technologies. The price volatility of natural gas is a barrier to the use of natural gas for baseload power generation and hinders capital investments in new natural gas energy systems. Within the past decade, the spot price of U.S. natural gas has ranged between about $1 and $14 per MMBtu ($0.94 to $13 per GJ), as shown in **Figure 3-1.**

5.2 Life Cycle Cost Model

The LCC model accounts for significant capital and O&M expenses incurred by the natural gas power system during construction and operation. It is a discounted cash flow analysis over the lifetime of a natural gas power plant, which includes a construction and operating period. The construction period is 3 years, making 2010 the first year of operation. The operating period is 30 years, making 2040 the last year of operation. Therefore, the total time frame of the LCC model is 33 years (3 years of construction and 30 years of operation). As a discounted cash flow model, it includes the nominal dollar expenditures during each year of construction and operation; all costs are escalated with respect to annual inflation rates and the interest accumulated on the debt portion of capital is accounted for during the construction period. All cost results are expressed in 2007 dollars because capital expenditures start in 2007, the first year of construction. Unless specified otherwise, this report shows all costs in 2007 dollars.

5.2.1 Fuel Costs

This analysis uses a natural gas price of $5.48/MMBtu, which is average delivered price of natural gas as projected by AEO 2012 through 2035 (EIA, 2012a). This price is reported by AEO in 2010 dollars, so a 3 percent annual inflation rate is used to adjust it to a 2007 basis of $5.00/MMBtu. The cost of natural gas is factored by the power plant performance characteristics (as shown in **Table 2-1**) to determine the fuel costs per MWh of production. The fuel costs for the three cases are summarized in the **Table 5-1**.

Table 5-1: Fuel Costs for Natural Gas Power

Parameter	Units	NGCC	NGCC/ccs	GTSC
Natural Gas Cost	2007$/MMBtu	5.00	5.00	5.00
Net Plant Efficiency	Percent	50.2%	42.8%	30.0%
Heat Rate	MMBtu/MWh	6.80	7.97	11.4
Fuel Costs for Natural Gas Power	2007$/MWh	34.0	39.9	56.9

5.2.2 Power Plant, Switchyard, and Trunkline Capital Costs

The capital costs for a 555-MW NGCC plant are $718/kW (NETL, 2010a). These costs represent the total overnight costs (TOC), which include the cost of equipment, materials, labor, engineering and construction management, contingencies related to the construction of a facility, and owner's costs (land acquisition, licenses, and administrative costs). An NGCC power plant with carbon capture has additional capital costs for CO_2 recovery equipment; the total capital costs (in terms of TOC) for an NGCC facility with carbon capture are $1,497/kW (NETL, 2010a).

For comparison, a survey of construction costs for NGCC power plants, including the NGCC technology plus balance of plant, indicated a range of costs, from about $670/kW to $1,427/kW installed capacity. Plant costs appear to have increased over the last 4-5 years, although the reason for this cost increase is not clear. The $670/kW figure is based on a plant completion announcement from 2006 (Hill & Engelenhoven, 2006). A separate review of power plant completion data prior to 2008 showed similarly low costs for plants installed during and prior to 2006. Preliminary data indicate that more recent installations have higher costs. For instance, American Municipal Power Company's proposed NGCC plant in Meigs County, Ohio, has an estimated projected total cost of $1,083/kW (Sergent, 2010). Additional planning cost projections by the Northwest Power and Conservation Council indicated projected total costs for an array of different NGCC plant configurations, which range from $1,244 to $1,427/kW (King, 2008).

NGCC costs vary based on the options included in plant configuration. New NGCC plants can be configured to provide baseload and load following power and also optionally reserve a portion of their nameplate capacity for peaking power production. For example, a plant being considered in Oregon will include 390 MW of baseload power plus an additional 25 MW of duct firing capacity, for a total peak production capacity of 415 MW. The total cost for this power plant, including overnight development and construction cost, is estimated at $1,245/kW (King, 2008). Fueled by a combination of low natural gas prices and pending or anticipated EPA regulations on coal-fired power plants, some existing small coal power plants are being transitioned over to natural gas power. A proposed conversion project in Painesville, Ohio, would convert an existing antiquated coal-fired power plant to natural gas combined cycle. The installation would require new equipment, but would also use existing onsite facilities from the coal plant. Total cost for the proposed 600 MW NGCC would be approximately $146 million, or about $243/kW (Lammers, 2010). No NGCC power plants with carbon capture systems are in commercial operation in the U.S., so no capital cost data are available for actual NGCC power plants with carbon capture.

The U.S. EPA is ending air emissions waivers for small, old coal-fired power plants, which is driving additional investment in NGCC technologies in some regions. In North Carolina, Duke Energy projects that it will have to close several smaller coal plants due to this change. To make up for the lost power, its longer-term plans include installation of two new NGCC power plants, both with capacities of 650 MW. Duke is also considering converting at least one of its existing coal plants to burn natural gas (Downey, 2010).

GTSC capital costs are not provided in NETL's baseline study, but were estimated at $299/kW (in 2007 dollars) by adjusting the equipment cost schedule for the NGCC facility. Unlike NGCC power plants, GTSC power plants do not have feedwater handling, cooling water, or steam turbine systems. The key systems of a GTSC power plant are combustion turbines, accessory electric systems, instrumentation and control systems, and buildings and structures.

This analysis also accounts for the capital costs for the switchyard and trunkline. These costs are the same for all systems of this analysis. The switchyard system is composed of two components. These include four SF_6 gas circuit breakers and eight aluminum vertical break (AVB) disconnect switches used in the switchyard. The cost for the 345 kilovolt (kV) circuit breaker was estimated based on a breaker rated at 362 kV, for which cost data were available. The AVB Disconnect Switches are rated at 345 kV. Cost for the switchyard components are based on disclosed and non-disclosed manufacturer estimates. In total, the switchyard capital costs are approximately $1,040,000 (Zecchino, 2008).

The trunkline system is made up of 294 towers and three aluminum-clad steel reinforced conductors spanning 80 kilometers (50 miles). The cost of the entire trunkline system is presumed to be $45,600,000 (ICF Consulting Ltd, 2002). Thus, the cost for the total switchyard and trunkline system, including all components, equals $46.6 million. All costs for the switchyard/ trunkline system include only the cost of purchasing the component. Installation, labor, and additional material costs that may be necessary to install the system components are not included in the cost estimate. O&M costs are presumed to be negligible and were not included in the analysis. It is assumed that switchyard/trunkline life is the same as the plant life (30 years); therefore, no capital replacement costs are considered in the analysis. A 7 percent transmission loss from the switchyard/trunkline system is considered when calculating the cost of electricity (COE) for each case.

5.2.3 Power Plant Operating and Maintenance Costs

The variable O&M costs for the natural gas power plants are based on the NETL bituminous baseline report (NETL, 2010a). The variable O&M costs for the NGCC facility (without CCS) are $1.32/MWh (NETL, 2010a). The variable O&M costs for the NGCC facility with CCS are $2.56/MWh (NETL, 2010a). The variable O&M costs for the GTSC facility are $0.96/MWh. The NETL bituminous baseline report (NETL, 2010a) does not have a GTSC case; the cost was estimated by including the maintenance costs of the NGCC case, but excluding the water and chemicals costs of the NGCC case. The replacement costs for the plant are included in the variable O&M costs shown therein. Fixed labor costs reflect labor costs in the U.S. Midwest, rather than the modeled NGCC location, in Mississippi. This is a data limitation, but the difference in rates is estimated to have negligible effect on the total COE.

The fixed O&M costs for the natural gas power plants are also based on the NETL bituminous baseline report (NETL, 2010a). The fixed O&M costs for the NGCC facility are $22,065/MW-yr, and the fixed O&M costs of the NGCC facility with CCS are $42,104/MW-yr (NETL, 2010a). This analysis assumes that the GTSC facility has the same fixed O&M costs as the NGCC facility.

5.2.4 CO_2 Pipeline Costs

For the NGCC with CCS scenario, the CO_2 pipeline transports supercritical CO_2 from the NGCC facility to a geological sequestration site. The costs of the CO_2 pipeline are based on a 161 km (100 mile) pipeline with a diameter of 30.5 centimeters (12 inches). The diameter of the pipeline is sized so that no booster compressor stations are required. Captured CO_2 is compressed at the power plant to a pressure of 2,200 psig (15.2 MPa) and exits the pipeline at 1,200 psig (8.4 MPa), an adequate pressure for injection. The following costs are based on NETL's quality guidelines for carbon dioxide transport and storage costs (NETL, 2010f) and are expressed in 2007 dollars.

The capital costs of the pipeline are based on materials, labor, right of way, one CO_2 surge tank, and miscellaneous costs. The total capital costs for the CO_2 pipeline in this analysis are $126 million. The NGCC facility with carbon capture has a net capacity of 474,000 kW, so the total capital costs for the 100-mile CO_2 pipeline are $265/kW.

The CO_2 pipeline has fixed O&M costs of $8,632/mile-yr. When factored by the pipeline distance and divided by the net capacity of the NGCC power plant with carbon capture, the fixed O&M costs for the CO_2 pipeline are $1,821/MW-yr. The CO_2 pipeline does not have any variable O&M costs.

5.2.5 CO_2 Injection Costs

The CO_2 injection site is a saline formation with a well that is 1,236 meters (4,055 feet) deep. CO_2 is injected at a pressure of 1,220 psig (8.4 MPa). One injection well can hold up to 10,300 short tons of CO_2. The following costs are based on NETL's quality guidelines for carbon dioxide transport and storage costs (NETL, 2010f) and are expressed in 2007 dollars.

The capital costs for the injection site are $24.7 million and include site screening and evaluation, well construction, and injection equipment. On the basis of the capacity of the associated NGCC power plant (474,000 kW), these capital costs are $52.2/kW.

The fixed O&M costs for the injection site are $141,000/year and include normal daily expenses, surface maintenance, and subsurface maintenance. On the basis of the capacity of the associated NGCC power plant (474 MW), the fixed O&M costs are $297/MW-yr.

The variable O&M costs for the injection site are $12,000/yr and account for the consumables used for the operation of the injection site. On the basis of the total electricity produced by the associated NGCC power plant (3.53 million MWh/yr), the variable O&M costs are $0.00344/MWh.

5.2.6 CO_2 Monitoring Costs

The CO_2 injection site is monitored during the life of the associated power plant (30 years) plus an additional 50 years. Monitoring methods include ongoing electromagnetic and gravity surveys as well as periodic seismic surveys. Monitoring costs are a variable O&M cost and are $0.306 per tonne of CO_2. On the basis of the associated NGCC power plant, which captures 1.34 million tonnes CO_2/yr and produces 3.53 million MWh/yr, the total costs for monitoring are $0.116/MWh.

The cost data used for this analysis are summarized in **Table 5-2**. All costs are expressed on the basis of the output of the natural gas power plants and are in 2007 dollars.

Table 5-2: Cost Data for Natural Gas Power[1]

Parameter	Units	NGCC	NGCC/ccs	GTSC
Total Overnight Costs (TOC)	**\$/kW**	**802**	**1,913**	**428**
Capital (power plant)	\$/kW	718	1,497	299
Capital (Trunkline & Switchyard)	\$/kW	84	98	129
Capital (CO_2 Pipeline)	\$/kW	N/A	265	N/A
Capital (CO_2 Injection)	\$/kW	N/A	52	N/A
Fuel Costs (Natural Gas)	**\$/MWh**	**34.0**	**39.9**	**56.9**
Total Variable O&M (Not Including Fuel Costs)	**\$/MWh**	**1.32**	**2.68**	**0.96**
Variable O&M (power plant)	\$/MWh	1.32	2.56	0.96
Variable O&M (CO_2 Pipeline)	\$/MWh	N/A	0	N/A
Variable O&M (CO_2 Injection)	\$/MWh	N/A	0.00344	N/A
Variable O&M (CO_2 Monitoring)	\$/MWh	N/A	0.116	N/A
Total Fixed O&M	**\$/MW-yr**	**22,065**	**44,222**	**22,065**
Fixed O&M (power plant)	\$/MW-yr	22,065	42,104	22,065
Fixed O&M (CO_2 Pipeline)	\$/MW-yr	N/A	1,821	N/A
Fixed O&M (CO_2 Injection)	\$/MW-yr	N/A	297	N/A
Net Plant Capacity	MW	555	474	360
Capacity Factor	%	85%	85%	85%
Daily Net Electricity (at 100% Capacity)	MWh/day	13,320	11,366	8,640
Annual Electricity Production	MWh/yr	4,132,530	3,526,426	2,680,560

5.2.7 Financial Assumptions

Cash flow is affected by several factors, including cost (capital, operating and maintenance [O&M], replacement, and decommissioning or salvage), book life of equipment, federal and state income taxes, equipment depreciation, interest rates, and discount rates. For NETL LCC assessments, modified accelerated cost recovery system (MACRS) depreciation rates are used. The financial assumptions of this LCC analysis are shown in **Table 5-3**.

[1] The capital and O&M costs shown in this table are not LC results, but represent only the net output of the power plant and do not reflect the 7 percent loss during electricity transmission and distribution.

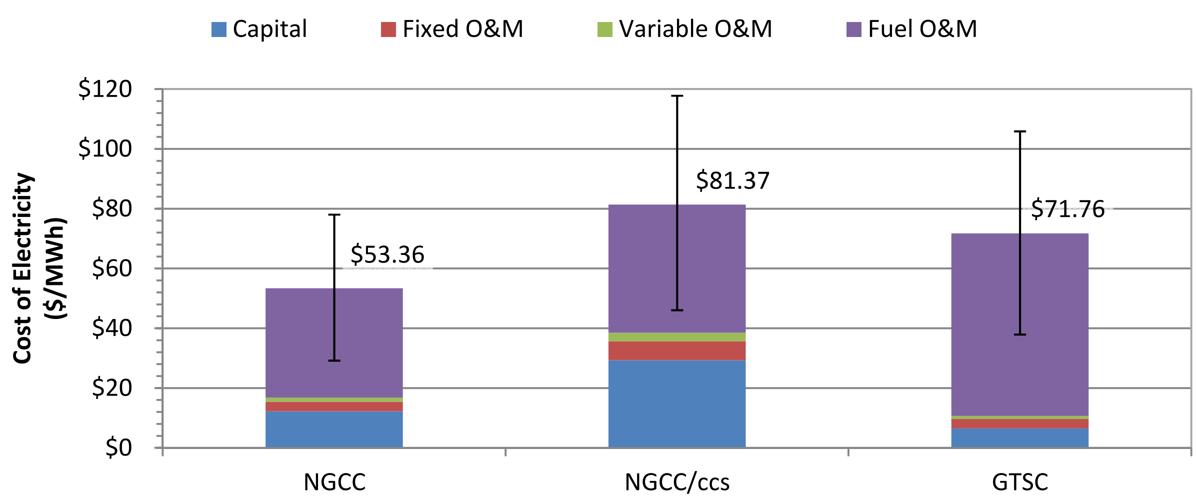
Table 5-3: Financial Assumptions for the LCC Model of Natural Gas Power

Financial Parameter	Nominal Cost Case
Financial Structure Type	Low Risk Investor-Owned Utility
Debt Fraction (1 - Equity), %	50%
Interest Rate, %	4.5%
Debt Term, Years	15
Plant Lifetime, Years	30
Depreciation Period (MACRS)	20
Tax Rate, %	38%
O&M Escalation Rate, %	3%
Capital Cost Escalation During Capital Expenditure, %	3.6%
Base Year	2007
Required Internal Rate of Return on Equity (IRROE)	12%

5.2.8 Cost Results

The COE for the three natural gas power scenarios are shown in **Figure 5-1**. At $53.36/MWh, the NGCC case (without CCS) has a lower COE than the other cases of this analysis. Compared to GTSC, NGCC has higher capital costs but lower fuel costs. The relatively high efficiency of an NGCC power plant results in relatively low fuel requirements that offset the relatively high capital costs of NGCC power. The COE of NGCC power is increased by 52 percent when a CCS system is added; this increase is due to the capital requirements of CCS and the reduced power plant efficiency caused by CCS.[1]

Figure 5-1: Life Cycle COE Results for Natural Gas Power



[1] When the LCC COE is calculated using a natural gas price of $6.55/MMBtu, the same value used by NETL's baseline (NETL, 2010a), the COE of NGCC and NGCC/CCS are $64.69/MWh and $94.66/MWh, respectively. These results are approximately 10% higher than the baseline results due to the 7 percent electricity T&D loss and additional capital costs for the switchyard and trunkline.

At $53.36/MWh, the NGCC case (without CCS) has a lower COE than the other cases of this analysis. Compared to GTSC, NGCC has higher capital costs but lower fuel costs. The relatively high efficiency of an NGCC power plant results in relatively low fuel requirements that offset the relatively high capital costs of NGCC power. The COE of NGCC power is increased by 52 percent when a CCS system is added; this increase is due to the capital requirements of CCS and the reduced power plant efficiency caused by CCS.[1]

The COE of GTSC power is $71.76/MWh. The GTSC system has low capital costs, but its relatively low efficiency results in high fuel costs.

The error bars in **Figure 5-1** represent the uncertainty in COE for each power technology. The total uncertainty for COE is a combination of uncertainties in capital costs, the price of natural gas, capacity factor, total tax rate, and variable O&M costs. The ranges for each of these uncertainties, as modeled in this analysis, are shown in **Table 5-4**.

Table 5-4: Uncertainty in Cost Parameters for Natural Gas Power

Parameter	Units	Low	EV	High	% Uncertainty
NGCC					
Natural Gas Price	2007$/MMBtu	2.50	5.00	7.50	+/-50%
Capital	2007$/kW	561	802	1,043	+/-30%
Total Tax Rate	%	28.0	38.0	48.0	+/-10%
Capacity Factor	%	80.0	85.0	90.0	+/-5%
Variable O&M	2007$/MWh	0.92	1.32	1.72	+/-30%
NGCC/ccs					
Natural Gas Price	2007$/MMBtu	2.50	5.00	7.50	+/-50%
Capital	2007$/kW	1,339	1,913	2,486	+/-30%
Total Tax Rate	%	28.0	38.0	48.0	+/-10%
Capacity Factor	%	80.0	85.0	90.0	+/-5%
Variable O&M	2007$/MWh	1.88	2.68	3.48	+/-30%
GTSC					
Natural Gas Price	2007$/MMBtu	2.50	5.00	7.50	+/-50%
Capital	2007$/kW	300	428	556	+/-30%
Total Tax Rate	%	28.0	38.0	48.0	+/-10%
Capacity Factor	%	80.0	85.0	90.0	+/-5%
Variable O&M	2007$/MWh	0.67	0.96	1.25	+/-30%

The uncertainty in capital costs reflects variability in material costs and unexpected costs of construction. This analysis uses an uncertainty range of +/-50 percent around the expected natural gas price to capture the variability in prices during the 30-year life of the power plant. Limited data are

[1] When the LCC COE is calculated using a natural gas price of $6.55/MMBtu, the same value used by NETL's baseline (NETL, 2010a), the COE of NGCC and NGCC/CCS are $64.69/MWh and $94.66/MWh, respectively. These results are approximately 10% higher than the baseline results due to the 7 percent electricity T&D loss and additional capital costs for the switchyard and trunkline.

available on the variable O&M costs for power production, so a large range of uncertainty (+/- 30 percent) was chosen for the variable O&M parameter. The uncertainty ranges for total tax rate and capacity factor are based on professional judgment.

The following figures are tornado graphs that show the extent of uncertainty that each of the above parameters contribute to the COE results. **Figure 5-2** shows the uncertainties for NGCC, **Figure 5-3** shows the uncertainties for NGCC with CCS, and **Figure 5-4** shows the uncertainties for GTSC. Each bar in the following figures is labeled with its associated low and high COE.

Figure 5-2: Life Cycle COE Uncertainty for NGCC Power

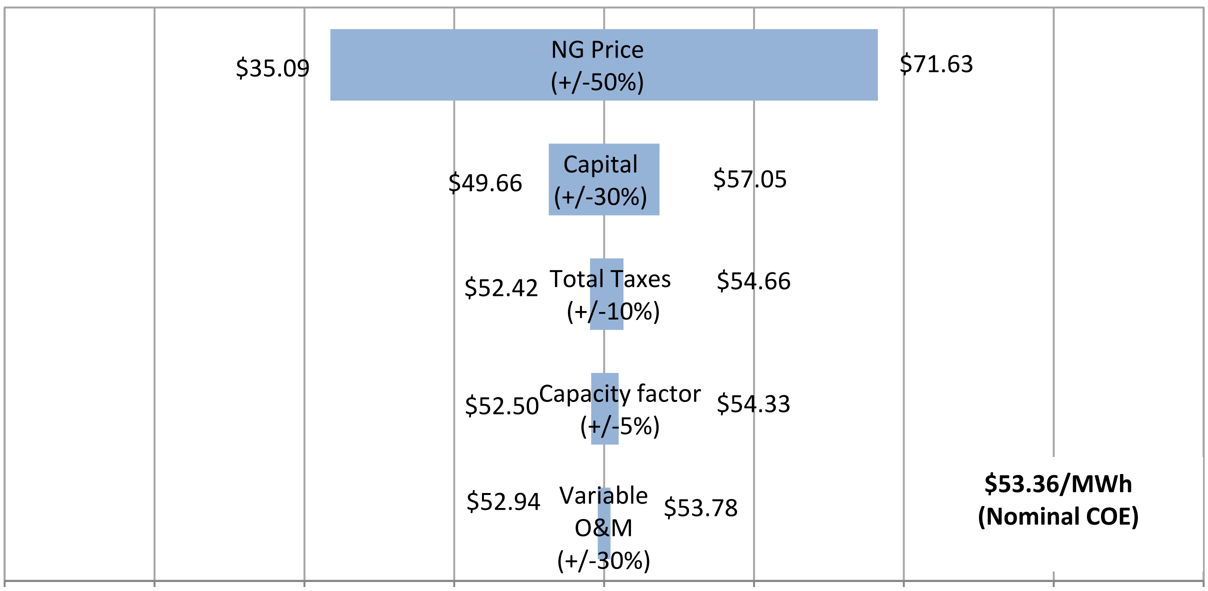


Figure 5-3: Life Cycle COE Uncertainty for NGCC Power with CCS

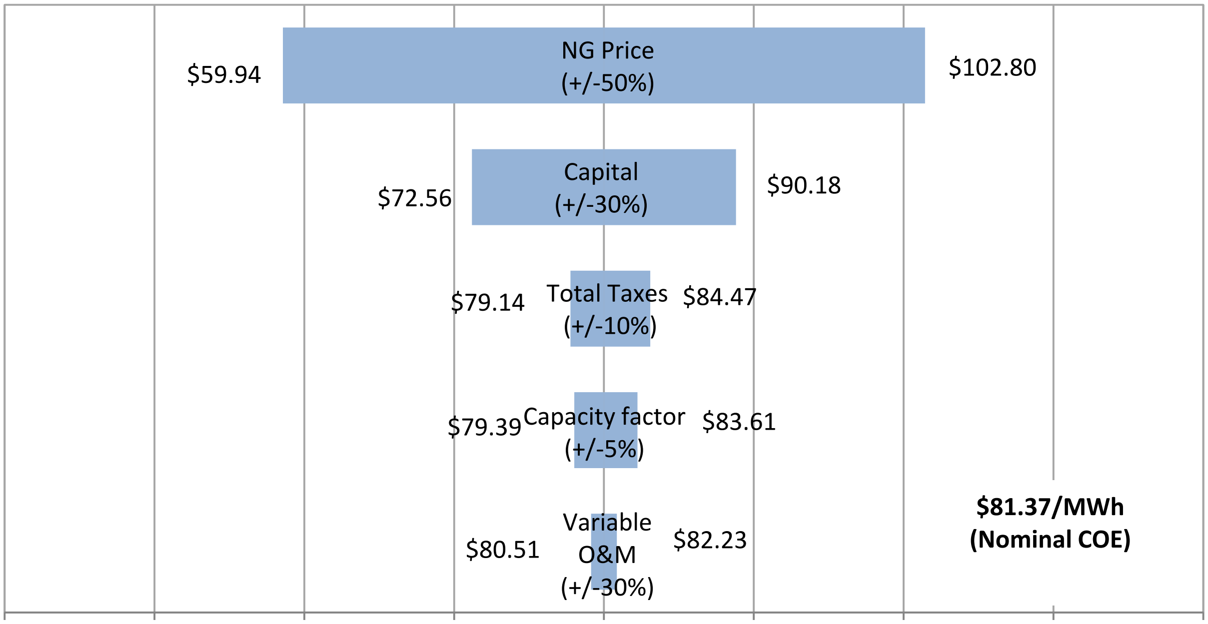
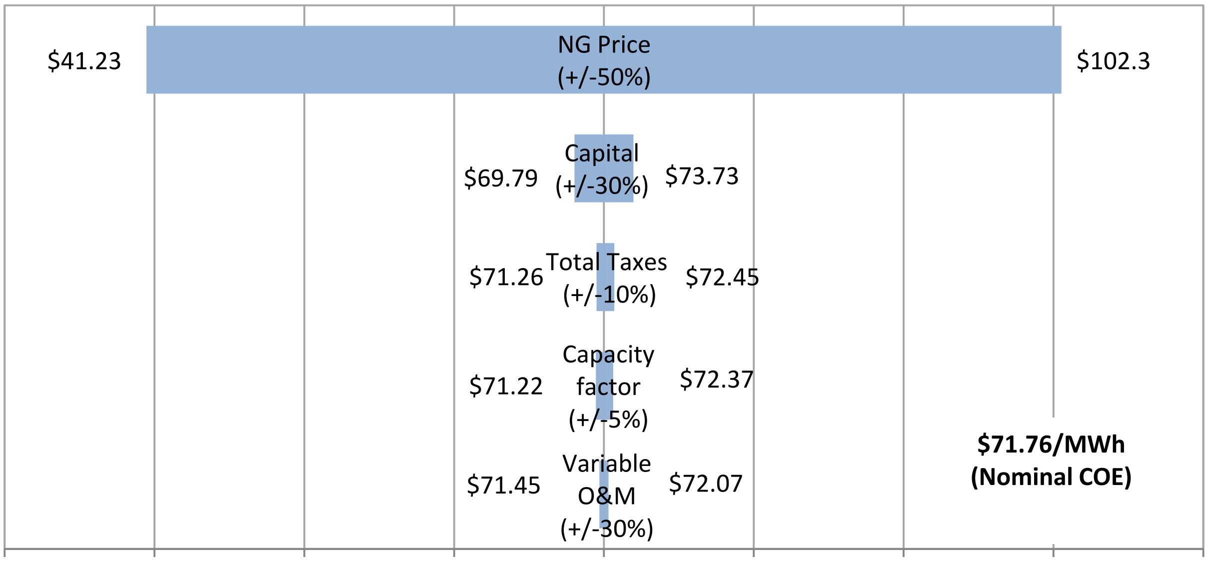


Figure 5-4: Life Cycle COE Uncertainty for GTSC Power



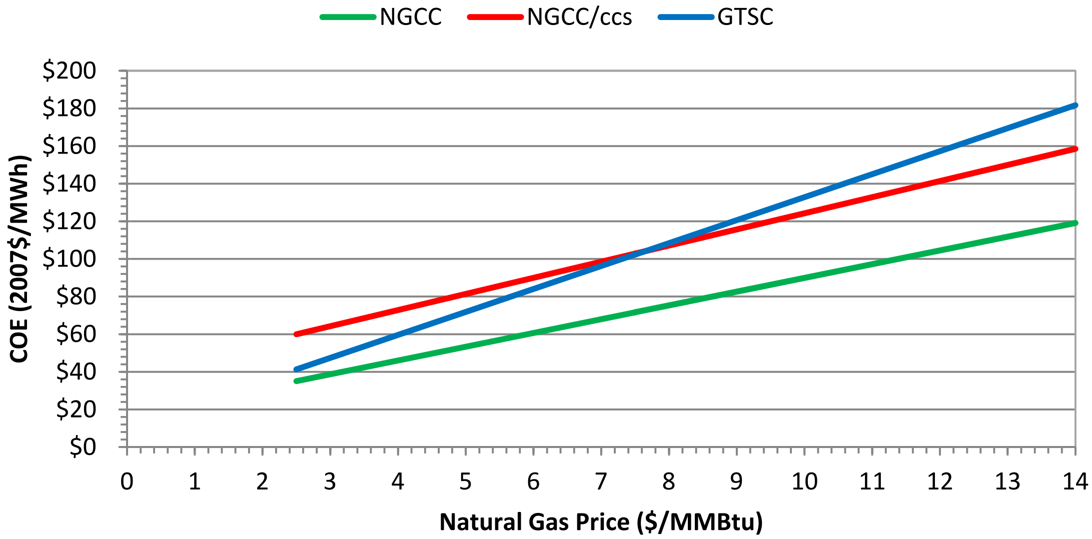
For all cases, the uncertainties in the total tax rate, capacity factor, and variable O&M do not cause as much uncertainty in COE as what is caused by the price of natural gas and capital costs

The price of natural gas contributes the most uncertainty to the COE for all systems. The GTSC systems respond the most to NG price uncertainty, followed by NGCC with CCS and NGCC. In comparison to the NGCC systems, GTSC consumes the most natural gas per MWh of electricity produced, so it makes sense that natural gas prices introduce more uncertainty to the COE of GTSC.

The NGCC systems have higher capital costs than the GTSC system, so the uncertainty in capital costs has a greater influence on the COE of NGCC power compared to the COE of GTSC power. For NGCC, the uncertainty in capital costs (+/- 30 percent around total capital costs) cause a COE uncertainty of approximately +/- 7 percent. For NGCC with CCS, the same level of uncertainty in capital costs causes a COE uncertainty of approximately +/- 11 percent. The COE of the GTSC scenario has only a +/- 3 percent response to the same level of capital cost uncertainty.

To provide further context on the relationship between natural gas price and COE, **Figure 5-5** shows the COE across a natural gas price range of $2/MMBtu to $14/MMBtu. Due to its higher capital costs and lower efficiency, the NGCC system with CCS always has a higher COE than the NGCC system. The GTSC system is more sensitive to changes in natural gas price than the other systems. At $2/MMBtu the COE of GTSC is comparable to the COE of NGCC, but at a natural gas price of approximately $7.5/MMBtu, the COE of GTSC is comparable to the COE of NGCC with CCS.

Figure 5-5: COE Sensitivity to Natural Gas Price



6 Barriers to Implementation

Barriers include technical concerns that could prevent the successful implementation of a technology.

The barriers of a fully developed Marcellus Shale gas play include depletion of surface water used for hydraulic fracturing, deterioration of water quality due to surface discharges of hydraulic fracturing water, and increased GHG emissions due to the episodic emissions from well completions and workovers.

The public perceives that the development of the Marcellus Shale gas play has the potential to result in groundwater and surface water contamination. Hydrofracking water contains chemical agents used to alter the viscosity of fracking water and to prevent bacterial growth in wells. If the casing of a natural gas well is not installed properly, the fracking chemicals can contaminate surrounding groundwater. Similarly, produced water from shale gas extraction also contains fracking chemicals that, if not treated properly before being discharged, can contaminate surface water.

There is also the possibility that the GHG emissions from Marcellus Shale extraction are higher than other well types. CH_4 is released during the completion of Marcellus Shale gas wells, when high volumes of flowback water come to the surface along with entrained CH_4. If recommended engineering practices are not observed during well completions and workovers, it is possible that large quantities of episodic emissions could be released to the atmosphere.

The LCA of this report provides a common basis for evaluating the water and air burdens associated with natural gas extraction from conventional and unconventional well types, including unconventional wells in the Marcellus Shale region. See **Section 4** for a life cycle perspective on the air and water burdens for natural gas extraction, delivery, and power generation.

The limited capacity of the existing pipeline transmission network is a possible barrier to the growth of natural gas extraction from Marcellus Shale. The natural gas transmission network transports large quantities of natural gas from the southern U.S. to markets in the Northeast, and recently, additional capacity has been added for transporting natural gas across the Rocky Mountain region, making it easier to transport gas from west to east. However, a surge in natural gas production in the Marcellus Shale region could exceed the existing pipeline capacity in the Northeast. According to a representative of El Paso Pipeline Partners (Langston, 2011), there are two ways of expanding natural gas pipeline capacity. The first is the installation of new compressor stations along the pipeline network, which increases the overall pressure of the network and allows more gas to be transported. Alternatively, new pipelines can be installed alongside existing pipelines. New pipelines may be costly, but one advantage of laying new pipelines next to existing pipelines is that pipeline companies have fewer barriers in establishing pipeline right-of-way (Langston, 2011).

7 Risks of Implementation

Risks of implementation are financial, environmental, regulatory, and/or public perception concerns that are obstacles to implementation.

Legislative actions are a barrier to the extraction of natural gas from Marcellus Shale. For example, in December 2010, Governor Paterson vetoed legislation that would have placed a six-month moratorium on hydrofracking in New York. Governor Paterson followed his veto with an executive order that prohibited horizontal drilling for six months (through July 2011), but still allowed hydrofracking of vertical wells (NYSDEC, 2010). This legislation was a compromise between natural gas producers who would prefer to continue the development of both vertical and horizontal natural gas wells, and environmental groups who argue that hydrofracking should not be performed at all (Applebome, 2010). In June 2011, Governor Cuomo, Paterson's successor, recommended lifting the horizontal drilling ban (Hakim & Confessore, 2011), and the New York State Department of Environmental Conservation released new recommendations that favored high-volume fracking on privately-owned land as long as it is not near aquifers (NYSDEC, 2011). These new recommendations were faced with opposition. For example, in February 2012 the New York State Supreme Court ruled that municipalities can use zoning laws to prohibit oil and natural gas drilling (Navarro, 2012).

Pennsylvania has also faced legislative uncertainty with respect to natural gas extraction. For instance, on June 28, 2011, the Pennsylvania House of Representatives canceled a vote on an impact fee on gas extracted from the Marcellus Shale. The proposed legislation would have assessed $50,000 per well for the first year of operation, followed by $25,000 in the second and third years, and $10,000 a year thereafter through the tenth year of operation (Scolforo, 2011). After months of controversy, in February 2012, Pennsylvania approved legislation that taxes the shale gas industry and sets standards for developing gas wells. Proponents of the legislation see it as a way for state and local governments to take advantage of a valuable revenue stream. Critics argue that the new laws do not adequately address the environmental and safety issues of shale gas extraction. (Tavernise, 2012)

8 Expert Opinions

The opinions from academic institutions and industry organizations mirror the key issues identified by the literature search of this analysis. Recent statements by researchers and industry experts have focused on the resource base, water use and quality, and GHG emissions of natural gas extraction from Marcellus Shale.

The UGGS recently estimated that the Marcellus Shale holds 84 Tcf of technically recoverable natural gas (Pierce, et al., 2011). Terry Engelder, a leading authority on Marcellus Shale and a professor of geosciences at Pennsylvania State University, has a significantly higher estimate. Engelder estimates that the formation holds 489 Tcf of recoverable natural gas (Engelder, 2009).

El Paso Pipeline Group accounts for a large share of natural gas pipeline transmission, including high capacity pipelines that bridge the supply of natural gas in the southern U.S. and Rocky Mountain regions to markets in the Northeast. As stated above, the limited capacity of the existing pipeline transmission network is a possible barrier to the growth of natural gas extraction from Marcellus Shale. However, according to a representative of El Paso Partners, it is possible to increase the capacity of an existing pipeline by adding new compressor stations or, if necessary, installing new pipelines alongside existing pipelines (Langston, 2011). Similarly, the collection networks from new natural gas wells can be connected to existing pipeline networks using “bolt on” manifolds between collection and transmission pipelines (Langston, 2011). According to the investor relations office at El Paso Pipeline Partners, the biggest barrier to the growth of the Marcellus Shale gas play will be the water use and quality issues, not pipeline capacity issues (Langston, 2011).

9 Summary

This analysis provides insight into the role of natural gas power as a future energy source in the U.S. The criteria used for evaluating the role of natural gas power are as follows:

- Resource Base
- Growth
- Environmental Profile
- Cost Profile
- Barriers to Implementation
- Risks of Implementation
- Expert Opinions

The U.S. **resource base** for natural gas has exhibited recent **growth**, and is expected to continue to expand in the near term, due to increased extraction potential of various shale gases. Shale gas resource expansion has been significant. For instance, horizontal drilling and hydraulic fracturing technologies could allow the recovery of Marcellus Shale natural gas sufficient to provide 20 years of natural gas supply to the U.S. (Engelder, 2009) at historic demand levels. The U.S. supply of natural gas consists of domestic and imported sources and includes conventional and unconventional technologies. The total U.S. demand for natural gas was 24.1 trillion cubic feet (Tcf) in 2010 and is projected to grow to 26.5 Tcf by 2035. This demand is balanced by conventional and unconventional supply sources, including an increasing share of shale gas as well as a small share of imports. Shale gas comprised 14 percent of the U.S. natural gas supply in 2009, 24 percent in 2010, and is projected to comprise 45 percent of the supply in 2035 (EIA, 2012a).

The **environmental profile** of this analysis considers life cycle GHG emissions, airborne emissions, water use, and land use associated with natural power. GHG emissions associated with RMA and RMT of natural gas ranged from a low of 6.1 g CO_2e/MJ for conventional offshore natural gas production, to 18.3 g CO_2e/MJ for LNG supplied from foreign sources. The 2010 domestic natural gas mix profile resulted in emissions of 10.9 g CO_2e/MJ. RMA and RMT were found to be most sensitive to well production rate, with conventional onshore extraction highly sensitive to liquid unloading frequency and venting rate and shale gas extraction highly sensitive to workover frequency and workover vent rate. The GHG results for natural gas RMA and RMT are also sensitive to the distance for pipeline transport.

On the basis of energy delivered to the power plant, the GHG emissions from natural gas RMA and RMT are higher than the GHG emissions from PRB coal and, in most cases, higher the GHG emissions from Illinois No. 6 coal. However, when expressed on a common basis of one unit of power production, the life cycle GHG emissions from natural gas are lower than those from coal. The life cycle GHG emissions for NGCC power production range from 162 kg CO_2e/MWh for an NGCC plant with CCS running on the domestic profile of natural gas to 488 kg CO_2e/MWh for an NGCC plant without CCS running on the domestic profile of natural gas. The current fleet of baseload natural gas power plants running on the domestic profile of natural gas has life cycle GHG emissions of 514 kg CO_2e/MWh. The life cycle GHG emissions for a GTSC plant running on domestic natural gas are 748 kg CO_2e/MWh, which is higher than NGCC technologies or the current fleet of baseload natural gas power because of the lower energy conversion efficiency of GTSC technology. For comparison, the life cycle GHG emissions from IGCC using Illinois No. 6 coal are 230 and 958 kg CO_2e/MWh (with and without CCS, respectively).

The water used for unconventional natural gas extraction has received significant attention, so it is worth focusing on the water flows that happen at natural gas wells. Produced water was highest for coal bed methane, and lowest for Marcellus shale, while total water use was highest for Barnett Shale. Per unit of power produced, conventional natural gas production technologies result in slightly reduced net water consumption, as compared to tight gas and shale gas production. The single exception is CBM, which due to high rates of water produced during extraction, results in considerably reduced net water consumption in comparison to all other natural gas sources.

The **cost profile** of natural gas power was calculated using a life cycle cost model of NGCC and GTSC systems. The NGCC case without CCS has the lowest COE ($53.36/MWh), and the NGCC case with CCS has the highest COE ($81.37/MWh). Capital costs are a large component of the COE for NGCC power, but the relatively high efficiencies of combined cycle technologies reduce the fuel costs per MWh of electricity production. The COE of the GTSC system is $71.76/MWh.

Key **barriers** include technical issues that could prevent or delay the implementation of a technology. If poor practices are used for the completion of unconventional wells, the flowback of water from hydrofracking could contaminate nearby surface water or groundwater aquifers. (The LCA conducted in this analysis shows that the water quality burdens for Marcellus Shale are similar to those for other types of natural gas.) The limited capacity of the existing natural gas pipeline network could also be a barrier to the immediate growth of shale gas production in the Northeast.

The **risks of implementation** include non-technical issues that hamper natural gas growth. Legislative uncertainty is a key risk of implementation. In 2010, New York placed a moratorium on horizontal drilling of natural gas wells in 2010 (NYSDEC, 2010). In June 2011, the New York State Department of Environmental Conservation released new recommendations that favored high-volume fracking on privately-owned land as long as it is not near aquifers (NYSDEC, 2011). These new recommendations were faced with opposition, including a New York State Supreme Court ruling in February 2012 that enforced the right of municipalities to use zoning laws to prohibit oil and natural gas drilling (Navarro, 2012). Pennsylvania has also faced legislative uncertainty with respect to natural gas extraction. After months of controversy, in February 2012, Pennsylvania approved legislation that taxes the shale gas industry and sets standards for developing gas wells. Critics argue that Pennsylvania’s new laws do not adequately address the environmental and safety issues of shale gas extraction (Tavernise, 2012).

Expert opinions include the outlook of natural gas industry players and experts, most of which are currently expressing positive forecasts for future natural gas resource availability.

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, industrial, and transportation applications in addition to an expanding role in power production. New technologies have allowed increased domestic production of natural gas and the development of natural gas formations that were not previously viable. The projected supply contributions afforded by new natural gas plays may keep the price of natural gas relatively low for the foreseeable future. However, since natural gas is comprised mostly of methane, the control of fugitive emissions is imperative to reduce the greenhouse gas footprint of natural gas extraction, processing, and transport.

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Appendix A:
Constants and Unit Conversion Factors

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Table A-1: Common Unit Conversions

Category	Input			Output	
	Value	Units		Value	Units
Mass	1	lb.	=	0.454	kg
	1	Short Ton	=	0.907	Tonne
Distance	1	Mile	=	1.609	km
	1	Foot	=	0.305	m
Area	1	$ft.^2$	=	0.093	m^2
	1	Acre	=	43,560	ft^2
Volume	1	Gallon	=	3.785	L
	1	$ft.^3$	=	28.320	L
	1	$ft.^3$	=	7.482	Gallons
	1	m^3	=	35.3	ft^3
Energy	1	Btu	=	1,055.056	J
	1	MJ	=	947.817	Btu
	1	kWh	=	3,412.142	Btu
	1	MWh	=	3,600	MJ

Table A-2: IPCC Global Warming Potential Factors (Forester, et al., 2007)

IPCC GWP Factor	Vintage	20-Year	100-Year	500-Year
CO_2	2007	1	1	1
CH_4	2007	72	25	7.6
N_2O	2007	289	298	153
SF_6	2007	16,300	22,800	32,600
CO_2	2001	1	1	1
CH_4	2001	62	23	7
N_2O	2001	275	296	156
SF_6	2001	15,100	22,200	32,400

Table A-3: Natural Gas Properties

Mass and Energy Densities	1	cubic foot	=	0.042	lb
	1	cubic foot	=	1,027	Btu

Appendix B: Data and Calculations for Life Cycle Inventory of Natural Gas and Coal Acquisition and Transport

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The data and methods used by NETL's LCA of natural gas acquisition and transport are provided below. Acquisition and transport data are also provided for coal.

B.1 Raw Material Acquisition: Natural Gas

In this analysis, the boundary of the RMA for natural gas begins with the extraction of natural gas from nature and ends with processed natural gas ready for pipeline delivery. Key activities in the RMA of natural gas are as follows:

- Well construction and installation
- Natural gas sweetening (acid gas removal)
- Natural gas dehydration
- Natural gas venting and flaring
- Natural gas compression
- Well decommissioning

The data sources and assumptions for calculating the greenhouse gas (GHG) emissions from each RMA activity are provided below. In most cases, the methane emissions are calculated by using standard engineering calculations around key gas field equipment, followed by the application of the Environmental Protection Agency (EPA) AP-42 emission factors as necessary.

Well Construction and Installation

NETL's LCA model of natural gas extraction includes the construction and installation activities for natural gas wells. Construction is defined as the cradle-to-gate burdens of key materials that embody key equipment and structures. Installation is defined as the activity of preparing a site, erecting buildings or other structures, and putting equipment in place.

The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. In the case of offshore extraction, a large platform is also required. A well is lined with a carbon steel casing that is held in place with concrete. A typical casing has an inner diameter of 8.6 inches, is 0.75 inches thick, and weighs 24 pounds per foot (NaturalGas.org, 2004). The weight of concrete used by the well walls is assumed to be equal to the weight of the steel casing. The total length of a natural gas well is variable, based on the natural gas extraction profile under consideration. The well lengths considered in this study are as follows: conventional onshore: 1,990 m; conventional offshore: 2,660 m; conventional onshore associated: 1,500 m; shale gas: 3,980 m; coal bed methane: 3,980 m; and tight gas: 2,525 m. The total weight of materials for the construction of a well bore is estimated by factoring the total well length by the linear weight of carbon steel and concrete.

The installation of natural gas wells includes the drilling of the well, followed by the installation of the well casing. Horizontal drilling is used for unconventional natural gas reserves where hydrocarbons are dispersed throughout a matrix of shale or coal. An advanced drilling rig has a drilling speed of 17.8 meters per hour, which translates to the drilling of a 7,000 foot well in approximately 10 days (NaturalGas.org, 2004). A typical diesel engine used for oil and gas exploration has a power of 700 horsepower and a heat rate of 7,000 Btu/hp-hr (EPA, 1995). The methane emissions from well installation is the product of the following three variables: heat rate of drilling engine (7,000 Btu/hp-hr), methane emission factor (EPA, 1995) for diesel combustion in stationary industrial engines (6.35E-05 lb./hp-hr), and the total drilling time (in hours).

The daily production rate of a natural gas well is an important factor in apportioning one-time construction activities or intermittent operations to a unit of natural gas production. Typical production rates vary considerably based on well type. Production rates also vary based on well specific factors, such as the age of the natural gas well. For instance, the average daily production rate for new, horizontal shale gas wells in the Barnett Shale region is as high as 2.5 million standard cubic feet (MMcf) per day, but declines at a rapid rate (Hayden & Pursell, 2005). The observed production rates in the Barnett Shale region decline 55 percent during the first year, 25 percent during the second year, 15 percent during the third year, and 10 percent each following year (Hayden & Pursell, 2005). The production rates for each type of natural gas well are shown in **Table B-23**. These production rates include the average production of natural gas wells in 2010 (the basis year of this analysis), as marginal production rates. Marginal production rates exclude poorly performing, mature wells that will likely be removed from service within a couple of years.

The construction and material requirements are apportioned to one kilogram of natural gas product by dividing them by the lifetime production of the well. The natural gas wells considered in this study are presumed to produce natural gas at the rates discussed above, with a lifetime of 30 years. Thus, construction and material requirements, and associated GHG emissions, are apportioned over the lifetime production rate specific to each type of natural gas well, based on average well production rates.

Natural Gas Sweetening (Acid Gas Removal)

Raw natural gas contains varying levels of hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas and causes fouling when combusted in equipment. The removal of H_2S from natural gas is known as sweetening. Amine-based processes are the predominant technologies for the sweetening of natural gas.

The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass is modeled in this analysis. This H_2S concentration is based on raw gas composition data compiled by the Gas Processors Association (Foss, 2004).

The energy consumed by the amine reboiler accounts for the majority of energy consumed by the sweetening process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. Approximately 0.30 moles of H_2S are removed per 1 mole of circulated amine solution (Polasek, 2006), the reboiler duty is approximately 1,000 Btu per gallon of amine (Arnold, 1999), and the reboiler has a thermal efficiency of 92 percent. The molar mass of amine solution is assumed to be 83 g/mole, which is estimated by averaging the molar mass of monoethanolamine (61 g/mole) and diethanolamine (105 g/mole). The density of the amine is assumed to be 8 lb./gal (3.62 kg/gal). The calculation of energy input per kilogram of natural gas product is shown in **Equation 1**.

$$\frac{0.005\ kg\ H_2S}{kg\ NG\ product} * \frac{1\ kg\ mol\ \ H_2S}{34\ kg\ H_2S} * \frac{1\ kg\ mol\ amine}{0.30 kg\ mol\ H_2S} * \frac{83\ kg\ amine}{kg\ mol\ amine} * \frac{1\ gal\ amine}{3.62\ kg\ amine} * \frac{1{,}000\ Btu\ reboiler\ duty}{gal\ amine} * \frac{1\ Btu\ energy\ input}{0.92\ Btu\ reboiler\ duty} = \frac{12.2\ Btu}{kg\ NG\ product} = \frac{26.9\ Btu}{lb\ NG\ product} \qquad \textbf{(Equation 1)}$$

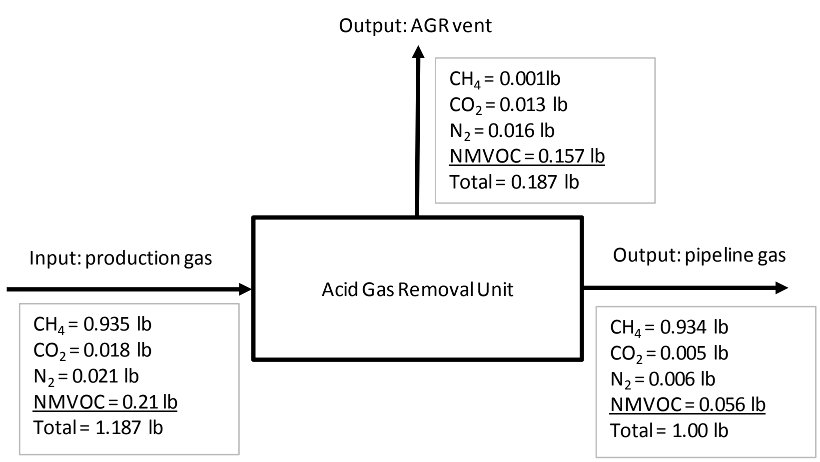
The amine reboiler combusts natural gas to generate heat for amine regeneration. This analysis applies EPA emission factors for industrial boilers (EPA, 1995) to the energy consumption rate discussed in the above paragraph in order to estimate the combustion emissions from amine reboilers.

The sweetening of natural gas is also a source of vented methane emissions. In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb. of methane per lb. per natural gas sweetened (API, 2009). The calculation of methane released by amine reboiler venting is shown in **Equation 2**.

$$\frac{0.0185\ tonne\ CH_4}{10^6\ cf\ NG} * \frac{1{,}000\ kg}{tonne} * \frac{2.205\ lb}{kg} * \frac{1cf}{0.042\ lb} = \frac{9.71 \times 10^{-4}\ lb\ CH_4}{lb\ NG} \quad \textbf{(Equation 2)}$$

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. Most of this CO_2 is absorbed by the amine solution during the sweetening of natural gas and is ultimately released to the atmosphere when the amine is regenerated. This analysis calculates the mass of naturally-occurring CO_2 emissions from the acid gas recovery (AGR) unit by balancing the composition of production gas (natural gas that has been extracted but has not undergone significant processing) and pipeline-quality gas. Production gas contains 1.52 mass percent CO_2 and pipeline-quality natural gas contains 0.47 mass percent CO_2. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and gas product, shows that 0.013 lb. of naturally-occurring CO_2 is vented per lb. of processed natural gas. The key constraints of this mass balance are the different compositions of input gas (production gas) and output gas (pipeline-quality gas) and the methane venting rate from amine regeneration. The mass balance around the AGR unit is illustrated by **Figure B-1.**

Figure B-1: Mass Balance for Acid Gas Removal



As shown by the mass balance around the AGR unit, the majority (84 percent by mass) of the AGR vent stream is NMVOC. At this concentration, NMVOCs are a high-value energy product. Thus, from an LCA perspective, NMVOCs are a valuable co-product of the AGR process. Co-product allocation is used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

In this analysis, the relative energy contents of the natural gas and NMVOC outputs from the AGR process are used as the basis for co-product allocation. The heating value of pipeline-quality natural gas is 24,452 Btu/lb. (which is calculated from the default study value of 1,027 Btu/cf). The heating value of NMVOCs is 21,025 Btu/lb., which is calculated from the composition of the vent stream from the AGR unit and the heating values of each NMVOC component (The Engineering Toolbox, 2011); the calculation of the heating value of NMVOC is shown in **Table B-1**. As shown by the mass balance (**Figure B-1**), 0.157 lbs. of NMVOC are produced for every lb. of natural gas produced. When these mass flows are converted to an energy basis using the above heating values, 88.1 percent of the product leaving the AGR process is natural gas and 11.9 percent is NMVOCs. Thus, the natural gas model allocates 88.1 percent of the energy requirements and environmental emissions of acid gas removal to the natural gas product.

Table B-1: Heating Value of NMVOC Co-Product from AGR Process

NMVOC Component	Percent Mass	Heating Value (Btu/lb)
CH_4	0%	23,811
Ethane	44.1%	20,525
Propane	26.7%	21,564
iso-Butane	5.9%	21,640
n-Butane	10.4%	21,640
iso-Pentane	3.0%	20,908
n-Pentane	3.9%	20,908
Hexanes	3.0%	20,526
Heptanes Plus	2.9%	21,000
Other (N_2 and CO_2)	0%	0
Composite Heating Value		21,025

The following table shows the energy consumption and GHG emissions for acid gas removal. These energy and emission factors do not account for the co-product allocation between natural gas and NMVOCs. The co-product allocation between natural gas and NMVOC is performed within the modeling software (GaBi).

For **Table B-2**, the energy used for acid gas removal is based on a 0.005 kg H_2S per of raw natural gas, a molar loading of 0.30 mol H_2S per mole of amine solution, and a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92 percent. The CH_4 venting factor assumes that the reboiler vent is not flared.

Table B-2: Acid Gas Removal (Sweetening)

Flow Name	Value	Units	Reference
Air Emission Factors[1,2,3]			
CO_2	2.86	kg CO_2/kg NG Fuel	API 2009[1]
N_2O	1.52E-05	kg N_2O/kg NG Fuel	API 2009[2]
CH_4 (Combustion)	5.48E-05	kg CH_4/kg NG Fuel	API 2009[2]
NO_X	2.38E-03	kg NO_X/kg NG Fuel	EPA 1995[3]
CO	2.00E-03	kg CO/kg NG Fuel	EPA 1995[3]
Pb	1.19E-08	kg Pb/kg NG Fuel	EPA 1995[3]
PM	1.81E-04	kg PM/kg NG Fuel	EPA 1995[3]
SO_2	1.43E-05	kg SO_2/kg NG Fuel	EPA 1995[3]
NMVOC	1.31E-04	kg NMVOC/kg NG Fuel	EPA 1995[3]
Energy Inputs and Outputs			
Reboiler Energy[4]	2.07	Btu/kg NG Product	API 2009
Reboiler Fuel[5]	2.02E-03	kg NG fuel/kg NG Product	Calculated
Air Emissions[6]			
CO_2	4.24E-04	kg CO_2/kg NG Product	Calculated
N_2O	2.26E-09	kg N_2O/kg NG Product	Calculated
CH_4 (Combustion)	8.10E-09	kg CH_4/kg NG Product	Calculated
CH_4 (Venting)[7]	9.71E-04	kg CH_4/kg NG Product	API 2009
NO_X	4.80E-06	kg NO_X/kg NG Product	Calculated
CO	4.03E-06	kg CO/kg NG Product	Calculated
Pb	2.40E-11	kg Pb/kg NG Product	Calculated
PM	3.65E-07	kg PM/kg NG Product	Calculated
SO_2	2.88E-08	kg SO_2/kg NG Product	Calculated
NMVOC	2.64E-07	kg NMVOC/kg NG Product	Calculated

Natural Gas Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the

[1] API combustion emissions for CO_2 were converted from the basis of tonnes/MMBtu to kg/NG fuel using the following factors: 1 tonne = 1,000 kg, 1 scf NG = 0.042 lb. NG, and 1 kg = 2.205 lb.

[2] API combustion emissions for N_2O and CH_4 were converted from the basis of lb./MMCF to kg/MMCF using the following factors: 1 scf NG = 0.042 lb. NG, and 1 kg = 2.205 lb.

[3] EPA combustion emissions for criteria air pollutants were converted from lb./MMCF to kg/kg NG using the following factors: 1 kg = 2.205 kg and 1 scf NG = 0.042 lb.

[4] The energy used for acid gas removal ("sweetening") is based on a 0.005 kg H_2S per of raw natural gas, a molar loading of 0.30 mol H_2S per mole of amine solution, and a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92 percent.

[5] The reboiler energy input was converted to the mass of fuel input using a heating value of 1,027 Btu/scf NG.

[6] Combustion air emissions are the product of the emission factors per MMBtu of fuel and the use rate of reboiler fuel.

water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

The fuel requirements of dehydration are a function of the reboiler duty. Due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs./MMcf. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs./MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 152,000 Btu/MMcf of dehydrated natural gas (as shown by **Equation 3** and **Equation 4** below). Assuming that the reboiler is fueled by natural gas, this translates to 1.48E-04 lb. of natural gas combusted per lb. of dehydrated natural gas (as shown by the equations below). The emission factor for the combustion of natural gas in boiler equipment produces 2.3 lb. CH_4/million cf natural gas (API, 2009). After converting to common units, the above fuel consumption rate and methane emission factor translate to 8.09E-09 lb. CH_4/lb. NG treated.

$$\frac{3.00\ gal\ glycol}{lb\ water} * \frac{1{,}124\ Btu}{gal\ glycol} * \frac{(49-4)\ lb\ water}{MMCF\ NG} = \frac{152{,}000\ Btu}{MMcf\ NG} \qquad \textbf{(Equation 3)}$$

$$\frac{152{,}000\ Btu}{MMcf\ NG} * \frac{MMcf\ NG}{10^6 cf\ NG} * \frac{1\ cf\ NG}{1027\ Btu} = \frac{1.48\times10^{-4}\ lb\ NG\ fuel}{lb\ NG\ product} \qquad \textbf{(Equation 4)}$$

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators are used to capture most of methane emissions from glycol strippers; nonetheless, small amounts of methane are vented from dehydrators. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 8.06E-06 lb. of methane is released for every pound of natural gas that is dehydrated.

For **Table B-3**, the energy used for dehydration is based on 3 gallons of glycol per pound of water removed, a reboiler duty of 1,124 Btu per gallon of glycol regenerated, and 45 pounds of water removed per MMcf of natural gas produced. The methane venting factor assumes that no flash separator is used to control venting emissions.

Table B-3: Natural Gas Dehydration

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG Fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG Fuel	API 2009
CH_4 (Combustion)	5.48E-05	lb CH_4/lb NG Fuel	API 2009
Energy Inputs and Outputs			
Reboiler Energy	1.52E-01	Btu/cf NG Product	API 2009
Reboiler Fuel	1.48E-04	lb NG fuel/lb NG Product	Calculated
Air Emissions			
CO_2	4.24E-04	lb CO_2/lb NG Product	Calculated
N_2O	2.26E-09	lb N_2O/lb NG Product	Calculated
CH_4 (Combustion)	8.10E-09	lb CH_4/lb NG Product	Calculated
CH_4 (Venting)	8.06E-06	lb CH_4/lb NG Product	API 2009

Natural Gas Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. The flaring emission factors published by the American Petroleum Institute (API, 2009) are based on the following recommendations by the Intergovernmental Panel on Climate Change (IPCC):

- If measured data are not available, assume flaring has a 98 percent destruction efficiency. Destruction efficiency is a measure of how much carbon in the flared gas is converted to CO_2 (API, 2009).
- The CO_2 emissions from flaring are the product the destruction efficiency, carbon content of the flared gas, the molar ratio of CO_2 to carbon (44/12). Methane is 75 percent carbon by mass, and the other hydrocarbons in natural gas are approximately 81 percent carbon by mass(Foss, 2004); the composite carbon content of natural gas is calculated by factoring these carbon compositions with the natural gas composition.
- Methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2 (API, 2009).
- N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.8 percent CH_4, 1.5 percent CO_2, 1.78 percent nitrogen, and 17.9 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). The mass composition of pipeline quality natural gas is 93.4 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.6 percent NMVOCs. The composition of production natural gas to model flaring during natural gas extraction, and the composition of pipeline quality natural gas is used to model flaring at the natural gas processing plant. The above method for estimating flaring emissions was applied to these gas compositions to develop flaring emission factors for production and pipeline natural gas. The following table summarizes the mass composition and flaring emissions for these two gas compositions.

Table B-4: Natural Gas Flaring

Emission	Production NG	Pipeline NG	Units	Reference
Natural Gas Composition				
CH_4	78.8%	93.4%	% Mass	EPA, 2011a
CO_2	1.52%	0.47%	% Mass	EPA, 2011a
Nitrogen	1.78%	0.55%	% Mass	EPA, 2011a
NMVOC	17.90%	5.57%	% Mass	EPA, 2011a
Flaring Emissions				
CO_2	2.67	2.69	lb CO_2/lb Flared NG	API, 2009
N_2O	8.95E-05	2.79E-05	lb N_2O/lb Flared NG	API, 2009
CH_4	1.53E-02	1.81E-02	lb CH_4/lb Flared NG	API, 2009

The venting rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Venting rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, venting rates have been parameterized in the model to allow uncertainty analysis.

Recent data indicate that only 51 percent of vented natural gas from conventional natural gas extraction operations is flared and the remaining 49 percent is released to the atmosphere (EPA, 2011a). The flaring rate is even lower for unconventional wells, which flare 15 percent of vented natural gas (EPA, 2011a). The flaring rate at natural gas processing plants is assumed to be 100 percent.

Venting from Well Completion

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells emit 36.65 Mcf of natural gas per completion and unconventional wells produce 9,175 Mcf of natural gas per completion (EPA, 2011a). Barnett Shale and tight gas wells are high pressure wells, and thus have higher completion venting than coal bed methane and conventional wells (EPA, 2011a).

When modeling tight gas, adjustments were made to EPA's emission factors for well completions and workovers. EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emissions are representative of high-pressure, tight gas wells in the San Juan and Piceance basins, which are horizontal wells that were completed using hydraulic fracturing and have an estimated ultimate recovery of 3 Bcf. A survey of tight gas production in the U.S. determined that an estimated ultimate recovery of 1.2 Bcf is more representative of U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. An emission factor of 3,670 Mcf of natural gas per episode for the completion and workover of tight gas wells is used.

Tight gas emissions are not the only emission factor adjusted for the model. While coal bed methane (CBM) wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have relatively low emission rates from completions and workovers. The CBM emission factor used for the completion and workover of CBM wells is 49.57 Mcf of natural gas (EPA, 2011a). This is much lower than the completion and workover emission factor that EPA recommends for unconventional wells (9,175 Mcf of natural gas).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb./cf (API, 2009) the natural gas emissions from conventional well completions are 1,538 lb./completion (698 kg/completion). For unconventional wells the venting rates are 386,000 lb./completion (175,000 kg/completion) for Barnett Shale, 2,090 lb./completion (946 kg/completion) for coal bed methane, and 154,000 lb./completion (70,064 kg/completion) for tight gas (EPA, 2011a). These emissions are on the basis of total natural gas emitted; methane comprises 78 percent of the mass composition of unprocessed natural gas, so methane represents 78 percent (by mass) of the above emission factors.

Venting from Well Workovers

The natural gas emissions from the workover of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells emit 2.454 Mcf of natural gas per workover and unconventional wells emit 9,175 Mcf of natural gas per workover. (Note that the workover emission factor for unconventional wells is the same as the completion emission factor for unconventional wells.) The workover venting rates for unconventional wells are assumed to be equal to their completion venting rates (EPA, 2011a).

This analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb./cf (API, 2009) and the conversion factor of 2.205 lb./kg, the methane emissions from well workovers are 103 lb./workover (46.7 kg/workover) for conventional wells. These emissions are on the basis of total natural gas emitted; methane comprises 78 percent of the mass composition of unprocessed natural gas, so methane represents 78 percent (by mass) of the above emission factors.

Unlike well completions, well workovers occur more than one time during the life of a well. The frequency of well workovers was calculated using EPA's accounting of the total number of natural gas wells in the U.S. and the total number of workovers performed per year (all data representative of 2007). For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

Venting from Liquid Unloading

Liquid unloading is necessary for conventional gas wells. It is not necessary for unconventional wells or associated gas wells.

The natural gas emissions from the unloading of liquid from conventional wells are based on emission factors developed by EPA. In 2007, conventional wells produced 223 Bcf/year (EPA, 2011a), which is 4.25 million metric tons per year using a natural gas density of 0.042 lb./cf. There were approximately 389,000 unconventional wells in 2007. When the annual emissions are divided by the total number of wells, the resulting emission factor is 10.9 metric tons of natural gas emitted per well-year. This emission factor the basis of total natural gas emitted; methane comprises 78 percent of the mass composition of unprocessed natural gas, so methane represents 78 percent (by mass) of the above emission factors.

Liquid unloading is a routine operation for conventional gas wells. The frequency of liquid unloading was calculated using EPA's assessment of two producers and the unloading activities for their wells (EPA, 2011a). From this sampling, EPA calculated that there are 31 liquid unloading episodes per well-year (EPA, 2011a).

When the emission factor for liquid unloading is divided by the average number of unloading episodes, the resulting methane emission factor is 776 lb./episode (352 kg/episode).

Venting from Wet Seal Degassing

The emission factor for wet seal degassing accounts for the natural gas lost during the regeneration of wet seal oil, which is used for centrifugal compressors. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010). According to EPA's sampling of these platforms, the emissions from wet seal oil degassing are 33.7 million m^3 of methane annually. These platforms produce 4.88 billion m^3 of natural gas annually. When the emission rate for this category is divided by the production rate, the resulting emission factor is 0.00690 m^3 of vented gas per m^3 of produced gas. Assuming the emissions have the same density as the produced gas, this emission factor is 0.00690 lb. of natural gas/lb. produced natural gas.

Fugitive Emissions from Pneumatic Devices

The extraction and processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction or processing site. Thus, this analysis assumes that the operation of pneumatic systems result in the emission of fugitive natural gas emissions.

Data for the fugitive emissions from pneumatic devices are based on EPA data for offshore wells, onshore wells, and gas processing plants (EPA, 2011a). EPA’s data is based on 2006 production (EPA, 2011a) and shows the methane emissions for specific wellhead and processing activities. This analysis translated EPA’s data to a basis of lb. methane per lb. of natural gas production by dividing the methane emission rate by the natural gas production rate. For example, the annual emissions from pneumatic devices used for offshore production are 7 MMcf of methane; when divided by the annual offshore production rate of 3,584,190 MMcf, this translates to an emission factor of 1.95E-06 lb. of methane per lb. of natural gas produced (this calculation assumes that the volumetric densities of methane and natural gas are the same). The fugitive emissions from pneumatic devices used by offshore wells, onshore wells, and natural gas processing plants are shown in the following table.

Table B-5: Fugitive Emissions from Pneumatic Devices

Location	MMcf/yr (EPA, 2011a)		Emission Factor
	CH_4 emission	NG Production	lb CH_4/lb NG
Onshore	52,421	19,950,828	2.63E-03
Offshore	7.0	3,584,190	1.95E-06
Processing	93	14,682,188	6.33E-06

Other Point Source and Fugitive Emissions

The emissions described above account for natural gas emissions from specific processes, including the episodic releases of natural gas during well completion, workovers, and liquid unloading, as well as routine releases from wet seal degassing, AGR, and dehydration. Natural gas is also released by other extraction and processing equipment. To account for these other emissions, NETL's model includes two additional emission categories: other point source emissions and other fugitive emissions. Other point source emissions account for natural gas emissions that are not accounted for elsewhere in model and can be recovered for flaring. Other fugitive emissions include emissions that are not accounted for elsewhere in the model and cannot be recovered for flaring.

EPA's Background Technical Support Document - Petroleum and Natural Gas Industry (EPA, 2011a) was used for quantifying the other point source and fugitive emissions from natural gas extraction and processing. A three-step process was used to filter EPA's venting and flaring data so that it is consistent with the boundary assumptions of this analysis:

1. Emissions that are accounted for by NETL's existing natural gas unit processes were not included in the categories for other point source and fugitive emissions. For example, EPA provides emission rates for well construction, well completion, dehydration, and pneumatic devices. The emissions from these activities are accounted for elsewhere in NETL's model and thus, to avoid double counting, are not included in the emission factors for other point and fugitive emissions.
2. Emissions that fall within NETL's boundary definitions for natural gas processing were moved from the natural gas extraction category to the natural gas processing category.
3. The EPA data (EPA, 2011a) does not discern between point source and fugitive emissions, so emissions were assigned to the point source or fugitive emission categories based on another EPA reference that provides more details on point source and fugitive emissions (Bylin, et al., 2010).

The process names shown in the first columns of the following tables (**Table B-6** through **Table B-8**) use the same names as shown by EPA's Background Technical Support Document (EPA, 2011a) and do not match the nomenclature used by NETL's natural gas model. EPA's process names have been retained in **Table B-6** through **Table B-8** to allow mapping between the source document (EPA, 2011a) and this document.

The following sections show the data used for other point source emissions from onshore extraction, offshore extraction, and natural gas processing.

Other Point Source and Fugitive Emissions from Onshore Extraction

The data for other point source and fugitive emissions from onshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from construction, dehydration, compressors, well completion, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Additionally, emissions from Kimray pumps, condensate tanks, and compressor blowdowns are re-categorized as natural gas processing emissions in NETL's model, and are thus not included in the emission factors for natural gas extraction. The data for these emission sources are shown in **Table B-6.** The resulting emission factors are shown in **Table B-9.**

Table B-6 also shows emissions for natural gas processing. EPA specifies these emissions within their onshore extraction data (EPA, 2011a), but for this analysis they have been moved to the processing category to be consistent with the boundaries of the NETL natural gas model.

Table B-6: Other Point Source and Fugitive Emissions from Onshore NG Extraction

Process	MMcf/yr (EPA, 2011a)	Existing NETL Unit Process	RMA (Extraction)		RMA (Processing)	
			Point Source	Fugitive	Point Source	Fugitive
Normal Fugitives						
Gas Wells	2,751	Well Construction/Installation				
Heaters	1,463		1,463			
Separators	4,718			4,718		
Dehydrators	1,297	Dehydrator				
Meters/Piping	4,556			4,556		
Small Reciprocating Compressor	2,926	Reciprocating Compressor				
Large Reciprocating Compressor	664	Reciprocating Compressor				
Large Reciprocating Stations	45	Reciprocating Compressor				
Pipeline Leaks	8,087			8,087		
Vented and Combusted						
Completion Flaring	0	Well Completion Operation				
Well Drilling	96	Well Completion Operation				
Coal Bed Methane	3,467	Well Completion Operation				
Pneumatic Device Vents	52,421	Pneumatic Device Operation				
Chemical Injection Pumps	2,814			2,814		
Kimray Pumps	11,572					11,572
Dehydrator Vents	3,608	Dehydrator Operation				
Condensate Tanks without Control	1,225				1,225	
Condensate Tanks with Control Devices	245				245	
Gas Engines, Compressor Exhaust Vented	11,680	Reciprocating Compressor				
Well Workovers						
Well Workovers, Gas Wells	47	Well Workovers				
Well Workovers, Well Clean Ups (LP Gas	9,008	Well Workovers				
Blowdowns						
Blowdowns, Vessel	31		31			
Blowdowns, Pipeline	129			129		
Blowdowns, Compressors	113					113
Blowdowns, Compressor Starts	253					253
Upsets						
Pressure Relief Valves	29			29		
Mishaps	70			70		
Total			**1,494**	**20,403**	**1,470**	**11,938**

Other Venting and Fugitive Emissions from Offshore Extraction

The data for other point source and fugitive emissions from offshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from drilling rigs, flares, centrifugal seals, glycol dehydrators, gas engines and turbines, and pneumatic pumps; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. The data for these emission sources are shown in **Table B-7.**

Table B-7: Other Point Source and Fugitive Emissions from Offshore NG Extraction

Process	MMcf/yr (EPA, 2011a)	Existing NETL Unit Process	RMA (Extraction)	
			Point Source	Fugitive
Amine gas sweetening unit	0.2	Acid Gas Removal		
Boiler/heater/burner	0.8		0.8	
Diesel or Gasoline Engine	0.01		0.01	
Drilling Rig	3	Well		
Flare	24	Flaring Operation		
Centrifugal Seals	358	Centrifugal Compressor		
Connectors	0.8			0.8
Flanges	2.38			2.38
OEL	0.1			0.1
Other	44			44
Pump Fugitive	1			0.5
Valves	19			19
Glycol Dehydrator	25	Dehydrator Operation		
Loading Operation	0.1			0.1
Separator	796			796
Mud Degassing	8		8	
Natural Gas Engines	191	Reciprocating		
Natural Gas Turbines	3	Centrifugal Compressor		
Pneumatic Pumps	7	Pneumatic Device		
Pressure Level Controls	2			2
Storage Tanks	7		7	
VEN Exhaust Gas	124		124	
Total			**140**	**865**

Other Venting and Fugitive Emissions from Natural Gas Processing

The data for other point source and fugitive emissions from natural gas processing are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from reciprocating compressors, centrifugal compressors, AGR units, dehydrators, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. The data for these emission sources are shown in **Table B-8**.

Table B-8: Other Point Source and Fugitive Emissions from NG Processing

Process	MMcf/yr (EPA, 2011a)	Existing NETL Unit Process	RMA (Processing)	
			Point Source	Fugitive
Normal Fugitives				
Plants	1,634		1,634	
Recip Compressors	17,351	Reciprocating Compressor		
Centrifugal Compressors	5,837	Centrifugal Compressor		
Vented and Combusted				
Compressor Exhaust, Gas	6,913	Reciprocating Compressor		
Compressor Exhaust, Gas	195	Centrifugal Compressor		
AGR Vents	643	Acid Gas Removal Operation		
Kimray Pumps (Glycol Pump)	177			177
Dehydrator Vents	1,088	Dehydrator Operation		
Pneumatic Devices	93	Pneumatic Device Operation		
Routine Maintenance				
Blowdowns/Venting	2,299		2,299	
Total			**3,933**	**177**

Table B-9 summarizes the other point source and fugitive emissions from natural gas extraction and processing**.** This table pulls the totals from **Tables B-6** through **Table B-8** and divides them by EIA's annual gas extraction and processing volumes (EIA, 2011) to calculate the emission factors used in NETL's natural gas model.

Table B-9: Summary of Point Source and Fugitive Emissions

Acquisition Process	2006 Annual Emissions (MMcf/yr)		2006 Annual Production (MMcf/yr) (EIA, 2011)	Emission Factors (kg CH_4/kg NG)		Emission Factors (lb CH_4/Mcf NG)	
	Point Source	Fugitive		Point Source	Fugitive	Point Source	Fugitive
Extraction - Onshore (From **Table B-6**)	1,494	20,403	19,950,828	7.49E-05	1.02E-03	3.15E-03	4.30E-02
Extraction - Offshore (From **Table B-7**)	140	865	3,584,190	3.90E-05	2.41E-04	1.64E-03	1.01E-02
Processing (From onshore data in **Table B-6**)	1,470	11,938	N/A	N/A	N/A	N/A	N/A
Processing (From gas plant data in **Table B-8**)	3,933	177	N/A	N/A	N/A	N/A	N/A
Processing (Sum of processing data in **Tables B-6 and B-8**)	5,403	12,115	14,682,188	3.68E-04	8.25E-04	1.55E-02	3.47E-02

Natural Gas Compression

Compressors are used to increase the gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. The inlet pressure depends on the pressure of the natural gas reservoir and pressure drop during gas processing and thus introduces uncertainty to the model. The outlet pressure of 800 psig is a standard pressure for pipeline transport of natural gas.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb./cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas. This energy rate represents the required *output* of the compressor shaft; the *input* fuel requirements for compression vary according to compression technology. The two types of compressors used for natural gas operations are reciprocating compressors and centrifugal compressors. These two compressor types are discussed below.

Reciprocating compressors account for an estimated 75 percent of wellhead compression in the Barnett Shale gas play, and are estimated to accounted for all wellhead compression at conventional onshore, conventional onshore associated, and coal bed methane wells. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/cf (API, 2009), a natural gas density of 0.042 lb./cf (API, 2009), and converting to kilograms translates to 217 kg of natural gas per MWh of reciprocating, gas-powered turbine output. This fuel factor represents the mass of natural gas that is combusted per compressor energy output. The carbon dioxide emissions from a gas-powered, 4-stroke reciprocating compressor are 110 lb./MMBtu of fuel input. Similarly, the methane emissions from the same type of reciprocating compressor are 1.25 lb./MMBtu of fuel input (EPA, 1995); these methane emissions result from leaks in compressor rod packing systems and are based on measurements conducted by the EPA on a sample of 22 compressors (EPA, 1995).

The emissions for the operation of wellhead compressors are shown in **Table B-10** below.

Table B-10: Gas-Powered Reciprocating Compressor Operations

Air Emission Factors (per MMBtu of Reciprocating Compressor Fuel)			
Flow Name	**Value**	**Units**	**Reference**
CO_2	110	lb/MMBtu fuel	EPA 1995
CH_4	1.25	lb/MMBtu fuel	EPA 1995
NO_X	8.47E-01	lb/MMBtu fuel	EPA 1995
CO	5.57E-01	lb/MMBtu fuel	EPA 1995
SO_2	5.88E-04	lb/MMBtu fuel	EPA 1995
PM	9.99E-03	lb/MMBtu fuel	EPA 1995
NMVOC	1.18E-01	lb/MMBtu fuel	EPA 1995
Energy Inputs and Outputs			
Flow Name	**Value**	**Units**	**Reference**
Output Shaft Energy	1.63E-04	MWh/kg	GE 2005
Heat Rate	217	kg NG/MWh	HARC 2006
Fuel Input[1]	3.54E-02	kg NG/kg NG	Calculated
Air Emissions[2]			
Flow Name	**Value**	**Units**	**Reference**
CO_2	0.095	kg/kg	Calculated
CH_4	1.08E-03	kg/kg	Calculated
NO_X	7.34E-04	kg/kg	Calculated
CO	4.82E-04	kg/kg	Calculated
SO_2	5.09E-07	kg/kg	Calculated
PM	8.65E-06	kg/kg	Calculated
NMVOC	1.02E-04	kg/kg	Calculated
Air Emission Factors			
CO_2	110 lb./MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	1.25 lb./MMBtu fuel	5.37E-04 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output Shaft Energy	7.39E-05 MWh/lb.	1.63E-04 MWh/kg	GE 2005
Heat Rate	478 lb. NG/MWh	217 kg NG/MWh	HARC 2006
Fuel Input	3.54E-02 lb. NG/lb. NG	3.54E-02 kg NG/kg NG	Calculated
Air Emissions			
CO_2	0.095 lb./lb. NG	0.095 kg/kg NG	Calculated
CH_4	1.08E-03 lb./lb. NG	1.08E-03 kg/kg NG	Calculated

[1] The fuel input is the product of output shaft energy and heat rate

[2] Air emissions are the product of EPA emission factors and compressor fuel input. The emission factors are converted to a metric basis using the following factors: 1 scf NG = 1,027 Btu NG = 0.042 lb. NG; 1 MMBtu = 1,000,000 Btu; 1 kg = 2.205 lb.

Gas powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage centrifugal compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb./cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas.

Table B-11: Gas-Powered Centrifugal Compressor Operations

Air Emission Factors (per MMBtu of Centrifugal Compressor Fuel)			
Flow Name	**Value**	**Units**	**Reference**
CO_2	110	lb/MMBtu Fuel	EPA 1995
CH_4	8.60E-03	lb/MMBtu Fuel	EPA 1995
N_2O	3.00E-03	lb/MMBtu Fuel	EPA 1995
NO_X	3.20E-01	lb/MMBtu Fuel	EPA 1995
CO	8.20E-02	lb/MMBtu Fuel	EPA 1995
SO_2	3.40E-03	lb/MMBtu Fuel	EPA 1995
PM	6.60E-03	lb/MMBtu Fuel	EPA 1995
NMVOC	2.10E-03	lb/MMBtu Fuel	EPA 1995
Energy Inputs and Outputs			
Flow Name	**Value**	**Units**	**Reference**
Output Shaft Energy	1.63E-04	MWh/kg	GE 2005
Heat Rate	201	kg NG/MWh	API 2009
Fuel Input[1]	3.28E-02	kg NG/kg NG	Calculated
Air Emissions[2]			
Flow Name	**Value**	**Units**	**Reference**
CO_2	0.088	kg/kg NG	Calculated
CH_4	6.89E-06	kg/kg NG	Calculated
N_2O	2.40E-06	kg/kg NG	Calculated
NO_X	2.56E-04	kg/kg NG	Calculated
CO	6.57E-05	kg/kg NG	Calculated
SO_2	2.72E-06	kg/kg NG	Calculated
PM10	5.29E-06	kg/kg NG	Calculated
NMVOC	1.68E-06	kg/kg NG	Calculated
Air Emission Factors			
CO_2	110 lb./MMBtu Fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	8.60E-03 lb./MMBtu Fuel	3.70E-06 kg/MJ fuel	EPA 1995
N_2O	3.00E-03 lb./MMBtu Fuel	1.29E-06 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output Shaft Energy	7.39E-05 MWh/lb.	1.63E-04 MWh/kg	GE 2005
Heat Rate	443 lb. NG/MWh	201 kg NG/MWh	API 2009
Fuel Input	3.28E-02 lb. NG/lb. NG	3.28E-02 kg NG/kg NG	Calculated
Air Emissions			
CO_2	0.088 lb./lb. NG	0.088 kg/kg NG	Calculated
CH_4	6.89E-06 lb./lb. NG	6.89E-06 kg/kg NG	Calculated
N_2O	2.40E-06 lb./lb. NG	2.40E-06 kg/kg NG	Calculated

[1] The fuel input is the product of output shaft energy and heat rate
[2] Air emissions are the product of EPA emission factors and compressor fuel input. The emission factors are converted to a metric basis using the following factors: 1 scf NG = 1,027 Btu NG = 0.042 lb. NG; 1 MMBtu = 1,000,000 Btu; 1 kg = 2.205 lb.

Electrically-powered centrifugal compressors account for an estimated 25 percent of wellhead compression in the Barnett Shale gas play, but were not found to be utilized in substantial numbers outside of the Barnett Shale. If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a city.

An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine. The average power range of electrically-driven compressor in the U.S. natural gas transmission network is greater than 500 horsepower. This analysis assumes that compressors of this size have an efficiency of 95 percent (DOE, 1996). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output. The upstream emissions associated with the generation of electricity are modeled with the fuel mix of the Electric Reliability Council of Texas (ERCOT) grid, which is representative of electricity generation in Texas (the location of Barnett Shale). The air emissions from electricity generation are based on the 2005 fuel mix for the ERCOT region (Texas) and are modeled by NETL's LCA model for power generation. Electric compressors have negligible methane emissions because they do not require a fuel line for the combustion of product natural gas and incomplete combustion of natural gas is not an issue (EPA, 2011c). Electric compressors are also recommended by EPA’s Natural Gas STAR program as a strategy for reducing system emissions of methane (EPA, 2011c).

Table B-12: Electrically-Powered Centrifugal Compressor Operations

Air Emissions from Electricity Generation (per MWh of electricity)[1]			
Flow Name	**Value**	**Units**	**Reference**
CO_2	809	kg/MWh	NETL 2010
N_2O	1.04E-02	kg/MWh	NETL 2010
CH_4	1.07	kg/MWh	NETL 2010
SF_6	1.01E-09	kg/MWh	NETL 2010
Pb	2.77E-05	kg/MWh	NETL 2010
Hg	5.11E-06	kg/MWh	NETL 2010
NH_3	3.23E-03	kg/MWh	NETL 2010
CO	2.73E-01	kg/MWh	NETL 2010
NO_X	1.38	kg/MWh	NETL 2010
SO_2	3.09	kg/MWh	NETL 2010
NMVOC	1.14E-01	kg/MWh	NETL 2010
PM10	6.21E-02	kg/MWh	NETL 2010
Energy Inputs and Outputs			
Flow Name	**Value**	**Units**	**Reference**
Output Shaft Energy	1.63E-04	MWh/kg	GE 2005
Heat Rate	1.053	MWh/MWh	API 2009
Electricity Input[2]	1.72E-04	MWh/kg NG	Calculated
Air Emissions[3]			
Flow Name	**Value**	**Units**	**Reference**
CO_2	0.139	kg/kg NG	Calculated
N_2O	1.78E-06	kg/kg NG	Calculated
CH_4	1.84E-04	kg/kg NG	Calculated
SF_6	1.73E-13	kg/kg NG	Calculated
Pb	4.76E-09	kg/kg NG	Calculated
Hg	8.77E-10	kg/kg NG	Calculated
NH_3	5.54E-07	kg/kg NG	Calculated
CO	4.68E-05	kg/kg NG	Calculated
NO_X	2.37E-04	kg/kg NG	Calculated
SO_2	5.31E-04	kg/kg NG	Calculated
NMVOC	1.95E-05	kg/kg NG	Calculated
PM10	1.07E-05	kg/kg NG	Calculated

[1] The air emissions from electricity generation are based on the 2005 fuel mix for the ERCOT region (Texas) and are modeled by NETL's LCA model for power generation

[2] The fuel input is the product of output shaft energy and heat rate

[3] Air emissions are the product of the upstream emissions for electricity production and compressor fuel input.

Well Decommissioning

This analysis assumes that the de-installation of a natural gas well incurs ten percent of the energy requirements and emissions as the original installation of the well.

Natural Gas Liquefaction

The unit processes for natural gas liquefaction include construction, installation/deinstallation, and operation processes.

Liquefaction Construction

Data on construction material inputs for the liquefaction facility were based on data from the Qatar Gas I LNG Plant, located in Ras Laffan, Qatar (Hydrocarbons Technology, 2009b). This facility has an annual natural gas liquefaction capacity of 7.2 million metric tonnes. The LNG facility was assumed to have a life of 30 years for this unit process. **Table B-13** lists the materials used in the construction of the LNG facility.

Table B-13: Construction Materials for Construction of a Liquefaction Facility

Materials	Amount	Units
Concrete	182,600	m^3
Structural Steel	9300	Tonnes
Steel Pipe	28000	Tonnes
Other Miscellaneous Equipment	32000	Tonnes

The weight of LNG facility construction per kilogram of natural gas liquefied/shipped was determined by dividing the individual component weights by the total natural gas flow through the LNG facility for a 30-year period. **Table B-14** shows the air emissions from the liquefaction construction unit process.

Table B-14: Air Emissions from Construction of a Liquefaction Facility

Emissions	Concrete, Ready Mixed, R-5-0 (100% Portland Cement) (kg/kg LNG)	US: SERC Power Grid Mix 2005 (kg/kg LNG)	Steel Pipe, Welded, BF, Manufacture (kg/kg LNG)	Steel Plate, BF, Manufacture (kg/kg LNG)	Total (kg/kg LNG)
Pb	0	7.57E-12	4.34E-10	4.39E-10	8.80E-10
Hg	0	2.13E-12	1.15E-11	2.76E-11	4.12E-11
NH_3	0	7.30E-10	0	0	7.30E-10
CO_2	1.17E-04	1.52E-04	1.42E-04	2.22E-04	6.33E-04
CO	1.51E-07	6.28E-08	1.05E-06	1.87E-06	3.14E-06
NO_X	3.58E-07	2.94E-07	2.32E-07	3.71E-07	1.26E-06
N_2O	0	2.01E-09	7.95E-09	1.15E-08	2.15E-08
SO_2	2.72E-07	8.62E-07	4.04E-07	5.04E-07	2.04E-06
SF_6	0	1.04E-15	0	0	1.04E-15
CH_4	0	1.67E-07	1.51E-07	1.68E-07	4.85E-07
CH_4 (Biotic)	5.34E-09	0	0	0	5.34E-09
VOC (Unspecified)	1.32E-08	2.12E-11	1.92E-08	3.29E-08	6.53E-08
PM (Unspecified)	0	0	0	0	0
Dust (Unspecified)	3.49E-07	1.64E-08	1.67E-07	5.31E-08	5.86E-07

Liquefaction Installation and Deinstallation

Data for installation/deinstallation of the liquefaction facility was based on environmental records provided by the AES Corporation on their Sparrows Point LNG import and regasification facility near Baltimore, Maryland (AES Corporation, 2009, 2007). Sparrows Point is a Federal Energy Regulatory Commission (FERC) approved 1.5 billion cubic feet per day (bcfd) regasification facility slated to be operational in 2010 (FERC, 2012). Although data was available for other processes, no energy use installation data was found that was specific to a liquefaction facility. The Sparrows Point data were determined to be the best available representation and is therefore used as surrogate data to describe the installation/deinstallation of the Atlantic LNG (ALNG) facility. Energy use and emissions associated with the installation/deinstallation of the facility include preparation of the onshore and offshore areas. Onshore activities include those related to construction of the facility itself, pier rehabilitation, and pier dredging using land equipment (AES Corporation, 2007). Offshore activities include pier dredging using marine equipment (AES Corporation, 2007). It is assumed that diesel consumption accounts for the majority of energy use and emissions during the installation of the terminal.

The Sparrows Point records listed the equipment, operating hours, horsepower, and diesel consumption (lbs. diesel per brake-specific horsepower-hour) for specific horsepower ranges for each installation activity as well as the following air emissions: PM, NO_X, sulfur dioxide (SO_2) based on a diesel sulfur content of 0.05 percent, CO, and unspecified hydrocarbons (HC) (AES Corporation, 2007). No data were provided for GHG, NH_3, of Hg emissions. Emission factors were applied to the calculated diesel consumption in order to calculate the emission of carbon dioxide (CO_2), N_2O, CH_4, NH_3, and Hg (EPA 1994; Conaway, Mason et al., 2005; EIA, 2008; EPA, 2002). The emissions were adjusted on the basis of the Darwin liquefaction facility land use and LNG processing quantities (Bechtel, 2004; Hydrocarbons Technology, 2009a), as Sparrows Point, as previously stated, is a regasification facility with different operations.

The Sparrows Point records express the installation activities on the basis of the installation of an entire facility (AES Corporation, 2007). Using an assumed lifetime of 30 years and a daily production rate of 1.5 bcfd of natural gas on which the raw unadjusted emissions were based, it was calculated that Sparrows Point will have a lifetime throughput of 3.13E+11 kilograms of natural gas. Therefore, the diesel consumption and air emissions for the installation of the LNG terminal were divided by the lifetime throughput to determine the diesel and air emissions on the basis of 1 kilogram of natural gas throughput. **Table B-15** shows the air emissions from the installation and de-installation of a liquefaction facility.

Table B-15: Emission from the Installation and Deinstallation of a Natural Gas Liquefaction Facility

Emissions	Liquefaction Installation/ Deinstallation (kg/kg LNG)	Diesel Extraction and Delivery (kg/kg LNG)	Total (kg/kg LNG)
Pb	0	4.34E-12	4.34E-12
Hg	2.99E-14	4.41E-13	4.71E-13
NH_3	2.57E-08	4.42E-12	2.57E-08
CO_2	6.04E-04	9.70E-05	7.01E-04
CO	3.79E-06	2.29E-07	4.02E-06
NO_X	5.96E-06	7.71E-07	6.73E-06
N_2O	1.53E-08	3.01E-09	1.83E-08
SO_2	1.20E-07	3.24E-07	4.44E-07
SF_6	0	0	0
CH_4	3.44E-08	6.04E-07	6.38E-07
CH_4 (Biotic)	0	0	0
VOC (Unspecified)	7.82E-07	1.18E-14	7.82E-07
PM (Unspecified)	4.13E-07	0	4.13E-07
Dust (Unspecified)	0	1.12E-07	1.12E-07

Liquefaction Operation

In general, the liquefaction facility receives natural gas from the pipeline, liquefies it into LNG, and stores it until it is ready to be loaded onto an LNG tanker. Trinidad and Tobago only have one LNG production facility, ALNG, which currently consists of four liquefaction trains (the largest, Train 4, has only recently come online). Train 1, Train 2, and Train 3 are designed to produce 3.3 metric tonnes per annum (MTPA) of LNG (ALNG, 2006). They all use the Phillips Optimized Cascade Liquefaction technology with slight modifications between the original Train 1 and the subsequently added Train 2, Train 3, and Train 4, which improve operability and reduce energy consumption as well as GHG emissions. Train 1, Train 2, and Train 3 were all designed to liquefy 3.3 MTPA (ALNG, 2006).

The process and technology used by the ALNG facility has most recently been licensed for the Darwin LNG plant in Australia (Hydrocarbons Technology, 2009a). The Darwin plant was designed to have a capacity of 3.24 MTPA. The Darwin LNG facility utilizes the same technology and processing scheme, but different equipment. For example, the Darwin facility uses six GE LM-2500 turbines rather than six GE Frame 5C/5D models. The process design is the same generation and approximate scale as ALNG Train 2 and Train 3.

The amount of natural gas input per production of 1 kg of LNG (the reference flow of this process) was calculated from a performance test for ALNG Train 1 (1.1303 kg raw natural gas/kg LNG) (Richardson, Hunter et al., 1999).

The CO_2 emissions reported for the 3.24 MTPA Darwin LNG Plant are 0.418 kg of CO_2 per kilogram of LNG (ConocoPhillips, 2005). Reported emissions also included criteria air pollutants (CAPs), PM, SO_2, NO_X, CO, VOC, N_2O, and an aggregated category of emissions for total organic compounds (TOCs) and CH_4 (labeled as "TOC/CH_4") (ConocoPhillips, 2005). No data are available to specify CH_4 and TOC emissions separately, and thus this unit process specifies these emissions as VOCs, which is a generic emission category that includes TOC and CH_4. Mercury (Hg) and Pb emissions were not included in the data obtained and is noted as a data limitation. Ammonia emissions were estimated using emissions data available in the national emissions inventory for the Kenai, Alaska terminal (EPA, 2005b). Ammonia emissions were divided by terminal LNG production to arrive at a discharge rate of 0.00063 kg NH_3/kg LNG (EIA, 2009b). Water intake and discharge data were obtained from an environmental management report for the Darwin plant (ConocoPhillips, 2005). Air emissions for the unit process are shown below in **Table B-16**.

Darwin LNG's utility usage is also assumed to be similar to that experienced by ALNG. Electricity is generated onsite by the gas turbines and any emergency power generation is assumed to be provided by diesel generators also located onsite. It is assumed that no electricity is produced for external consumption; all electricity generation and consumption occurs within the boundaries of this unit process and does not need to be accounted for in any input or output flows of the unit process.

Table B-16: Air Emissions for Operation of a NG Liquefaction Facility

Emissions	NG Liquefaction, Storage & Ship Loading, Operation (kg/kg LNG)
Pb	0
Hg	0
NH_3	6.33E-04
CO_2	4.19E-01
CO	6.71E-05
NO_X	4.68E-04
N_2O	5.02E-07
SO_2	1.34E-05
SF_6	0
CH_4	0
CH_4 (Biotic)	0
VOC (Unspecified)	6.71E-04
PM (Unspecified)	1.35E-05
Dust (Unspecified)	0

LNG Tanker

The unit processes for an LNG tanker include construction, transport operations, and berthing/deberthing operations.

LNG Tanker Construction

This process models the materials used in the construction of a LNG ocean going tanker. The boundary of this unit process is the tanker itself. The reference flow of this unit process is the LNG Tanker construction per kilogram of natural gas delivered from Trinidad and Tobago; all material flows are expressed on this basis.

While LNG tankers built around this time would be anticipated to be in service, the data is old and is considered a data limitation. This LNG tanker has a capacity of 125,000 cubic meters of capacity and was assumed to have a life of 30 years for this unit process.

Data from the LNG tanker operations unit process was used in conjunction with this data set to estimate the total quantity of LNG that could be transported by the tanker over its anticipated lifetime assuming it was permanently assigned to the ALNG (Trinidad & Tobago)-Trunkline LNG (Louisiana) route. The weight of tanker construction per kilogram of LNG delivered was determined by dividing the individual construction material (carbon steel, 304 stainless steel, and aluminum) quantities listed in the construction data set by the total natural gas delivered over a 30-year period. The air emissions from this process are shown in **Table B-17**.

Table B-17: Air Emissions from LNG Tanker Operations

Emissions	Aluminum Sheet Mix (kg/kg LNG)	Steel Plate, BF, Manufacture (kg/kg LNG)	Steel, Stainless, 304 2B, 80% Recycled (kg/kg LNG)	Total (kg/kg LNG)
Pb	1.01E-10	9.00E-10	0.00E+00	1.00E-09
Hg	8.16E-12	5.65E-11	0.00E+00	6.47E-11
NH_3	2.34E-09	0.00E+00	0.00E+00	2.34E-09
CO_2	6.27E-04	4.54E-04	5.25E-05	1.13E-03
CO	5.41E-06	3.83E-06	9.07E-08	9.33E-06
NO_X	1.10E-06	7.60E-07	1.09E-07	1.97E-06
N_2O	1.09E-08	2.36E-08	0.00E+00	3.45E-08
SO_2	3.47E-06	1.03E-06	2.08E-07	4.71E-06
SF_6	6.36E-14	0.00E+00	0.00E+00	6.36E-14
CH_4	1.03E-06	3.45E-07	0.00E+00	1.37E-06
CH_4 (Biotic)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
VOC (Unspecified)	2.48E-08	6.75E-08	0.00E+00	9.24E-08
PM (Unspecified)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dust (Unspecified)	1.06E-06	1.09E-07	5.77E-08	1.23E-06

LNG Tanker Transport Operation

It was assumed that the LNG tanker is a 138,000-cubic meter carrier and that propulsion is fueled by cargo boil-off and then supplemented with diesel fuel in Wartsila dual-fuel engines (University of Texas, 2012; Namba, 2003; Wärtsilä Corporation, 2005). The amount of boil-off is variable for both the laden and ballast voyages (current values are industry average) (Hasan, Zheng et al.). The percent usable cargo volume and heel (quantity in percent of initial volume remaining for fuel for return trip) quantity are also variable. After accounting for the quantity of LNG used for fuel and heel, the actual delivered quantity of LNG is 127,498 cubic meters (University of Texas, 2010; Hasan, Zheng et al.; Namba, 2003; DOE, 2005; Panhandle Energy, 2006). This value forms the basis for the emissions from the tanker and is a calculated reference flow.

CO_2 and NO_X emissions are calculated from engine manufacturer specifications (Wärtsilä Corporation, 2005), assuming that the engines are running at 75 percent load (higher emissions than for 100 percent load). Remaining air pollutant emissions were estimated by applying the EPA AP-42 emission factors for Large Stationary Diesel and All Stationary Dual-Fuel Engines (EPA, 1995). Emission factors were not available for NH_3 or Hg. **Table B-18** shows the air emissions from LNG tanker operations.

Table B-18: Air Emissions from Transport Operations of an LNG Tanker

Emissions	Diesel at Refinery (kg/kg LNG)	LNG Tanker Transport – Operation (kg/kg LNG)	Total (kg/kg LNG)
Pb	2.18E-10	0.00E+00	2.18E-10
Hg	1.84E-11	0.00E+00	1.84E-11
NH_3	3.22E-08	0.00E+00	3.22E-08
CO_2	4.81E-03	6.61E-02	7.09E-02
CO	7.03E-06	4.82E-04	4.89E-04
NO_X	1.49E-05	8.63E-04	8.78E-04
N_2O	8.25E-08	0.00E+00	8.25E-08
SO_2	1.93E-05	6.55E-07	2.00E-05
SF_6	1.83E-14	0.00E+00	1.83E-14
CH_4	5.01E-05	1.48E-04	1.98E-04
CH_4 (Biotic)	0.00E+00	0.00E+00	0.00E+00
VOC (Unspecified)	2.09E-08	7.26E-05	7.26E-05
PM (Unspecified)	0.00E+00	2.63E-05	2.63E-05
Dust (Unspecified)	2.85E-07	0.00E+00	2.85E-07

LNG Tanker Berthing and Deberthing Operation

LNG tanker escort, docking, and berthing/deberthing air emissions at Trunkline LNG are modeled using air emissions estimates generated for these operations at a proposed power plant at Mare Island in Vallejo, California (URS, 2003). The docking facility is sized to service a 70,000 dead weight ton (DWT) LNG tanker with an LNG storage capacity of 130,000 cubic meters (URS, 2003). Each LNG tanker would be propelled by steam boiler/steam turbine systems. The inbound voyage would rely on LNG vapors as a fuel source. Vessel hoteling during LNG offloading would rely on 0.5 percent sulfur fuel oil. The outgoing voyage would use 1.5 percent sulfur heavy fuel oil (URS, 2003). Round trip fuel consumption (pilot on to pilot off, including offloading of cargo) would require 120 metric tons equivalent of fuel oil (URS, 2003).

Each LNG tanker would be escorted by tugs, and each tug would be equipped with a 4200 horsepower (hp) diesel engine. Each tanker would require two tugs for escort per visit (2 hours each way/tug or 8 tug-hours total/visit). Four tugs would assist berthing (2 hours/tug or 8 tug-hours total/visit) and three tugs would assist deberthing (1 hours/tug or 3 tug-hours total/visit). One additional tug would be on standby duty for approximately 15 hours per tanker visit (URS, 2003).

Future emissions regulations will mandate lower sulfur content for marine diesel powered vessels. Operations with lower fuel sulfur content have not been modeled and are considered a data limitation. Emissions of CO_2, CH_4, and N_2O were estimated using fuel emissions factors (EPA, 2002). A Hg emission factor for heavy fuel oil was not readily available for inclusion in the modeling and is considered a data limitation. Ammonia emissions were estimated using emission factors for combustion sources (EPA, 1994). Hg emissions from diesel fuel were estimated using a Hg concentration in fuel study (Conaway, Mason et al., 2005). **Table B-19** shows the air emissions from with tanker berthing and deberthing.

Table B-19: Air Emissions from LNG Tanker Berthing and Deberthing Operations

Emissions	Diesel at Refinery (kg/kg LNG)	Fuel Oil Heavy at Refinery (kg/kg LNG)	LNG Tanker Escort, Docking, & Berthing/Deberthing (kg/kg LNG)	Total (kg/kg LNG)
Pb	5.73E-12	4.42E-11	0.00E+00	4.99E-11
Hg	4.85E-13	4.12E-12	4.09E-14	4.65E-12
NH_3	8.47E-10	8.00E-09	2.69E-07	2.77E-07
CO_2	1.27E-04	1.03E-03	8.42E-03	9.57E-03
CO	1.85E-07	1.36E-06	2.86E-06	4.41E-06
NO_X	3.93E-07	2.84E-06	3.51E-05	3.84E-05
N_2O	2.17E-09	1.63E-08	2.14E-07	2.33E-07
SO_2	5.08E-07	3.85E-06	2.33E-05	2.76E-05
SF_6	4.83E-16	3.72E-15	0.00E+00	4.20E-15
CH_4	1.32E-06	9.15E-06	6.14E-07	1.11E-05
CH_4 (Biotic)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
VOC (Unspecified)	5.49E-10	3.82E-09	1.38E-06	1.39E-06
PM (Unspecified)	0.00E+00	0.00E+00	6.47E-06	6.47E-06
Dust (Unspecified)	7.49E-09	5.45E-08	0.00E+00	6.20E-08

Natural Gas Regasification

The unit processes for natural gas regasification include regasification facility construction, installation, and operation.

Natural Gas Regasification Construction

This process models the materials used in the construction of an LNG regasification facility. The boundaries of this unit process start at the transport tanker boundary and end at the natural gas pipeline to the distribution network. The reference flow of this unit process is the regasification facility construction required for 1 kg of LNG regasified; all material flows are expressed on this basis.

The data set for the construction of a regasification facility were obtained for the Marmara Ereğlisi LNG Import Terminal located in Turkey (NACO, 2009). This facility has an annual LNG regasification capacity of 4.6 million tons (EIA, 2003). The tons units in the NACO data set are assumed to be metric tons given the context of other metric units in the data set; this is noted as a data limitation (NACO, 2009). Also, a value for carbon steel pipe is not given in the data set and is noted as a data limitation. The regasification facility was assumed to have a life of 30 years for this unit process. **Table B-20** shows the materials used for construction of a regasification facility.

Table B-20: Construction Materials for a Regasification Facility

Materials	Amount	Units
Concrete	66,705	Cubic Meters
Structural Steel	12,162	Tons
Reinforcement Steel	8,562	Tons

Natural Gas Regasification Installation and Deinstallation

The activities for the installation of an LNG terminal include the preparation of onshore and offshore areas. Onshore activities include those related to construction of the facility, pier rehabilitation, and pier dredging using land equipment (AES Corporation, 2007). Offshore activities include pier dredging using marine equipment. It is assumed that diesel consumption accounts for the majority of energy and emissions for the installation of the terminal.

The diesel consumption for the installation of the LNG terminal was calculated using an environmental impact statement (EIS) that listed the equipment, operating hours, horsepower, and diesel consumption for specific horsepower ranges for each installation activity (AES Corporation, 2007). The diesel consumption was shown on the basis of pounds of diesel per brake-specific horsepower-hour. The EIS also included the following air emissions: PM, NO_X, SO_2 based on a diesel sulfur content of 0.05 percent, CO, and unspecified HC (AES Corporation, 2007). The EIS did not include emissions of GHGs, NH_3, or Hg. Emission factors were applied to the calculated diesel consumption in order to calculate the emission of CO_2, N_2O, CH_4, NH_3, and Hg (EPA, 1994; Conaway, Mason et al., 2005; EIA, 2009b).

The EIS expressed the installation activities on the basis of the installation of an entire facility (AES Corporation, 2007). Using an assumed lifetime of 30 years and a daily production rate of 1.5 billion cubic feet of natural gas, this translates to a lifetime throughput of 3.13E+11 kilograms of natural gas (FERC, 2012). The diesel consumption and air emissions for the installation of the LNG terminal were divided by the lifetime throughput to determine the diesel and air emissions on the basis of 1 kilogram of natural gas throughput. **Table B-21** shows the air emissions from the installation/deinstallation of a regasification facility.

Table B-21: Air Emissions from Installation/Deinstallation of a Regasification Facility

Emissions	US: Diesel Extraction and Delivery (kg/kg LNG)	Regasification Installation/ Deinstallation (kg/kg LNG)	Total (kg/kg LNG)
Pb	8.79E-13	0.00E+00	8.79E-13
Hg	8.93E-14	6.05E-15	9.53E-14
NH_3	8.96E-13	5.21E-09	5.21E-09
CO_2	1.97E-05	1.22E-04	1.42E-04
CO	4.64E-08	5.93E-07	6.39E-07
NO_X	1.56E-07	1.36E-06	1.51E-06
N_2O	6.09E-10	3.09E-09	3.70E-09
SO_2	6.57E-08	2.59E-08	9.16E-08
SF_6	0.00E+00	0.00E+00	0.00E+00
CH_4	1.22E-07	6.96E-09	1.29E-07
CH_4 (Biotic)	0.00E+00	0.00E+00	0.00E+00
VOC (Unspecified)	2.39E-15	1.23E-07	1.23E-07
PM (Unspecified)	0.00E+00	7.51E-08	7.51E-08
Dust (Unspecified)	2.28E-08	0.00E+00	2.28E-08

Natural Gas Regasification Operation

The data sources for this unit process include mass balance and equipment data as reported by the Trunkline LNG facility to FERC (FERC, 2012), emission factors for the combustion of natural gas and diesel (EPA, 1995), and criteria pollutants provided by Trunkline LNG (DEQ Louisiana, 2007). The LNG regasification facility uses a small portion of LNG input as fuel for a turbine and vaporizers. According to FERC documentation, natural gas is consumed at an average rate of 1.61 percent of the regasified natural gas product. Thus, for the production of 1 kg of regasified natural gas, 0.016 kg of natural gas is used for onsite energy generation, which translates to a total of 1.016 kg of LNG input.

The combustion of natural gas for onsite energy results in air emissions of CO_2, CH_4, and N_2O. These air emissions were calculated by applying the amount of natural gas combusted (0.016 kg) to generic emission factors for natural gas combustion in stationary equipment (EPA, 1995). In order to perform this calculation, it was necessary to convert natural gas from a mass basis to an energy basis; a heating value of 1,025 Btu/scf and density of 0.042 lbs./scf were used to complete this calculation.

In addition to the natural gas that is used for onsite energy, diesel is used for pumps and backup generators. The amount of diesel required per unit of production was determined from an equipment list provided by Trunkline LNG to FERC. This equipment list itemizes the fuel consumption per hour and annual hours of operation for each piece of diesel equipment used at the LNG regasification facility. This data was used to calculate annual diesel fuel consumption. The diesel fuel consumption is then divided by Trunkline's output to determine diesel usage on a per kilogram of regasified natural gas basis.

The CO_2 emissions from diesel combustion were calculated using emission factors for diesel combustion in diesel equipment (EPA, 2005a). This calculation was similar to the calculation used for CO_2 emissions from natural gas combustion as described above. Generic emission factors for diesel combustion were used to calculate CH_4 and N_2O emissions from diesel combustion in construction equipment (EPA, 2005b).

CAPs for the LNG regasification facilities were based on emission data reported by the Trunkline LNG facility (DEQ Louisiana, 2007). These emissions include VOC, NO_X, SO_2, PM, and CO. Trunkline LNG did not report any NH_3, Pb, or Hg emissions and is considered a data limitation.

Trunkline LNG combusts natural gas (primarily CH_4) and uses the combustion heat to regasify LNG. During this process, the cooled exhaust stream results in condensed water discharge. The amount of water discharged is estimated by assuming all the natural gas burned is CH_4 (for larger organic molecules [ethane, propane, etc.], larger quantities of water would be produced for each molecule combusted). Water production was estimated based on the amount of water produced from complete combustion of the amount of gas used for fuel. This quantity was then determined per kilograms of natural gas output.

Estimation of electricity requirements was based on FERC data reporting the operational power costs for Trunkline LNG activities. Electricity price data obtained from EIA was used to complete the estimate of the electrical energy consumed. The energy requirement was then expressed on the basis of kilograms of natural gas output. **Table B-22** shows the air emissions from regasification operations.

Table B-22: Air Emissions from Natural Gas Regasification Operations

Emissions	SERC Power Grid Mix 2005 (kg/kg NG)	Diesel at Refinery (kg/kg NG)	Regasification Operations (kg/kg NG)	Total (kg/kg NG)
Pb	2.10E-10	2.60E-13	0.00E+00	2.11E-10
Hg	5.93E-11	2.21E-14	0.00E+00	5.94E-11
NH_3	2.03E-08	3.85E-11	0.00E+00	2.03E-08
CO_2	4.23E-03	5.76E-06	3.84E-02	4.26E-02
CO	1.75E-06	8.41E-09	9.40E-06	1.12E-05
NO_X	8.18E-06	1.79E-08	1.71E-05	2.53E-05
N_2O	5.60E-08	9.86E-11	7.34E-08	1.29E-07
SO_2	2.40E-05	2.31E-08	1.40E-07	2.41E-05
SF_6	2.88E-14	2.19E-17	0.00E+00	2.88E-14
CH_4	4.63E-06	5.99E-08	3.16E-03	3.17E-03
CH_4 (Biotic)	0.00E+00	0.00E+00	0.00E+00	0.00E+00
VOC (Unspecified)	5.90E-10	2.49E-11	1.26E-06	1.26E-06
PM (Unspecified)	0.00E+00	0.00E+00	1.58E-06	1.58E-06
Dust (Unspecified)	4.55E-07	3.41E-10	0.00E+00	4.55E-07

Compilation of Natural Gas Processes

All energy and emissions data for the extraction of natural gas are described above. The compilation of these data into a model for natural gas extraction involves the connection of all unit processes into an interdependent network.

To model the extraction of natural gas from different sources (onshore, offshore, unconventional, etc.) it is necessary to tune each unit process within this network with a set of source-specific parameters. The assumptions used to adjust the unit processes into profiles of specific natural gas types are shown in **Table B-23**.

Table B-23: Natural Gas Modeling Parameters

<table>
<tr><th colspan="2">Property (Units)</th><th>Onshore</th><th>Associated</th><th>Offshore</th><th>Tight Gas</th><th>Barnett Shale</th><th>Marcellus Shale</th><th>CBM</th></tr>
<tr><td colspan="9">Natural Gas Source</td></tr>
<tr><td colspan="2">Contribution to 2010 U.S. Domestic Supply</td><td>22%</td><td>6.6%</td><td>12%</td><td>27%</td><td>21%</td><td>2.5%</td><td>9.4%</td></tr>
<tr><td rowspan="3">Average Production Rate (Mcf/day)</td><td>Low</td><td>46</td><td>85</td><td>1,960</td><td>77</td><td>192</td><td>201</td><td>73</td></tr>
<tr><td>EV</td><td>66</td><td>121</td><td>2,800</td><td>110</td><td>274</td><td>297</td><td>105</td></tr>
<tr><td>High</td><td>86</td><td>157</td><td>3,641</td><td>143</td><td>356</td><td>450</td><td>136</td></tr>
<tr><td rowspan="3">Marginal Production Rate (Mcf/day)</td><td>Low</td><td>415</td><td>279</td><td>4,325</td><td>77</td><td>69</td><td>74</td><td>73</td></tr>
<tr><td>EV</td><td>593</td><td>399</td><td>6,179</td><td>110</td><td>137</td><td>148</td><td>105</td></tr>
<tr><td>High</td><td>771</td><td>519</td><td>8,033</td><td>143</td><td>206</td><td>223</td><td>136</td></tr>
<tr><td colspan="2">EUR (Estimated Ultimate Recovery) (BCF)</td><td>0.72</td><td>1.32</td><td>30.7</td><td>1.20</td><td>3.00</td><td>3.25</td><td>1.15</td></tr>
<tr><td colspan="9">Natural Gas Extraction Well</td></tr>
<tr><td colspan="2">Flaring Rate (%) (Range shown in parenthesis)</td><td colspan="3">51% (41 - 61%)</td><td colspan="4">15% (12 - 18%)</td></tr>
<tr><td colspan="2">Well Completion (Mcf natural gas/episode)</td><td colspan="3">37</td><td>3,670</td><td>9,175</td><td>9,175</td><td>49.6</td></tr>
<tr><td colspan="2">Well Workover (Mcf natural gas/episode)</td><td colspan="3">2.44</td><td>3,670</td><td>9,175</td><td>9,175</td><td>49.6</td></tr>
<tr><td colspan="2">Lifetime Well Workovers (Episodes/well)</td><td colspan="3">1.1</td><td colspan="4">3.5</td></tr>
<tr><td colspan="2">Liquids Unloading (Mcf natural gas/episode)</td><td>23.5</td><td>N/A</td><td>23.5</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Lifetime Liquid Unloadings (Episodes/well)</td><td>930</td><td>N/A</td><td>930</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Valve Emissions, Fugitive (lb CH_4/Mcf)</td><td colspan="2">0.11</td><td>0.0001</td><td colspan="4">0.11</td></tr>
<tr><td colspan="2">Other Sources, Point Source (lb CH_4/Mcf)</td><td colspan="2">0.003</td><td>0.002</td><td colspan="4">0.003</td></tr>
<tr><td colspan="2">Other Sources, Fugitive (lb CH_4/Mcf)</td><td colspan="2">0.043</td><td>0.01</td><td colspan="4">0.043</td></tr>
<tr><td colspan="9">Acid Gas Removal (AGR) and CO_2 Removal Unit</td></tr>
<tr><td colspan="2">Flaring Rate (%)</td><td colspan="7">100%</td></tr>
<tr><td colspan="2">CH_4 Absorbed (lb CH_4/Mcf)</td><td colspan="7">0.04</td></tr>
<tr><td colspan="2">CO_2 Absorbed (lb CO_2/Mcf)</td><td colspan="7">0.56</td></tr>
<tr><td colspan="2">H_2S Absorbed (lb H_2S/Mcf)</td><td colspan="7">0.21</td></tr>
<tr><td colspan="2">NMVOC Absorbed (lb NMVOC/Mcf)</td><td colspan="7">6.59</td></tr>
<tr><td colspan="9">Glycol Dehydrator Unit</td></tr>
<tr><td colspan="2">Flaring Rate (%)</td><td colspan="7">100%</td></tr>
<tr><td colspan="2">Water Removed (lb H_2O/Mcf)</td><td colspan="7">0.045</td></tr>
<tr><td colspan="2">CH_4 Emission Rate (lb CH_4/Mcf)</td><td colspan="7">0.0003</td></tr>
<tr><td colspan="9">Valves & Other Sources of Emissions</td></tr>
<tr><td colspan="2">Flaring Rate (%)</td><td colspan="7">100%</td></tr>
<tr><td colspan="2">Valve Emissions, Fugitive (lb CH_4/Mcf)</td><td colspan="7">0.0003</td></tr>
<tr><td colspan="2">Other Sources, Point Source (lb CH_4/Mcf)</td><td colspan="7">0.02</td></tr>
<tr><td colspan="2">Other Sources, Fugitive (lb CH_4/Mcf)</td><td colspan="7">0.03</td></tr>
<tr><td colspan="9">Natural Gas Compression at Gas Plant</td></tr>
<tr><td colspan="2">Compressor, Gas-Powered Reciprocating (%)</td><td>100%</td><td>100%</td><td></td><td>100%</td><td>75%</td><td>100%</td><td>100%</td></tr>
<tr><td colspan="2">Compressor, Gas-Powered Centrifugal (%)</td><td></td><td></td><td>100%</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="2">Compressor, Electric Centrifugal (%)</td><td></td><td></td><td></td><td></td><td>25%</td><td></td><td></td></tr>
</table>

Production Rates for Conventional Onshore Natural Gas Wells

The purpose of this discussion is to describe the data sources and calculations used to determine the typical production rate of conventional onshore natural gas wells. The population of conventional onshore wells is a lot more diverse that other types of natural gas wells, and thus it is necessary to distinguish between the large population of wells with low production rates and the relatively small population of wells with high production rates.

The Energy Information Administration (EIA) collects production data for oil and gas wells in the U.S. and organizes it according to production rates. The EIA data for total U.S. production is shown in **Table B-24**. The data in **Table B-24** are copied directly from EIA (EIA, 2010b) and show 22 production rate brackets. The lowest bracket includes wells that produce less than one barrel of oil equivalent (BOE) per day, and the highest bracket represents wells that produce more than 12,800 BOE per day. The EIA data have separate groups for oil wells and gas wells; from these data, we know that in 2009 the U.S. had 363,459 oil wells and 461,388 gas wells. These data also show the co-production of oil at gas wells as well as the average per well production rate within each production rate bracket.

The goal of this discussion is to focus on conventional onshore gas extraction. The data in **Table B-24** includes offshore production, and to develop a more accurate representation of onshore gas production, it is necessary to remove offshore data from the total U.S. profile. The EIA also has data for offshore production, as shown by **Table B-25**. By subtracting the offshore data from the total U.S. well profile, production data exclusive to onshore wells can be determined, as shown in **Table B-26**.

Table B-24: U.S. Total 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010b)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (MMbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (Bcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/Day)
0-1	127,734	35.1	15.4	0.9	0.4	4.8	0.1	91,005	19.7	73.4	0.3	2.4	0.7	0.0
1-2	45,649	12.6	21.8	1.3	1.4	9.5	0.6	45,034	9.8	131.1	0.5	8.3	1.3	0.1
2-4	47,803	13.2	45.3	2.8	2.7	22.3	1.3	60,930	13.2	358.3	1.5	16.6	3.6	0.2
4-6	27,625	7.6	43.6	2.7	4.4	29.4	3.0	43,009	9.3	428.4	1.8	28.0	4.4	0.3
6-8	21,816	6.0	48.3	2.9	6.2	36.7	4.7	32,564	7.1	457.8	1.9	39.4	4.5	0.4
8-10	15,482	4.3	42.9	2.6	7.7	40.0	7.2	24,829	5.4	451.1	1.9	50.8	4.3	0.5
10-12	12,642	3.5	43.8	2.7	9.7	33.5	7.4	18,967	4.1	420.5	1.8	62.1	4.1	0.6
12-15	11,801	3.2	50.3	3.1	11.9	37.3	8.8	21,718	4.7	591.1	2.5	76.2	5.7	0.7
15-20	13,895	3.8	75.1	4.6	15.2	60.8	12.3	23,974	5.2	841.3	3.5	98.5	7.7	0.9
20-25	8,157	2.2	56.6	3.4	19.6	46.2	16.1	16,539	3.6	744.2	3.1	126.5	7.5	1.3
25-30	6,276	1.7	52.3	3.2	23.7	46.5	21.1	11,638	2.5	644.9	2.7	156.7	5.1	1.2
30-40	7,207	2.0	75.3	4.6	30.0	69.0	27.5	16,083	3.5	1,122.3	4.7	197.4	9.5	1.7
40-50	3,684	1.0	49.0	3.0	39.1	42.1	33.5	9,959	2.2	895.6	3.7	255.6	7.1	2.0
50-100	7,934	2.2	159.7	9.7	59.4	171.4	63.7	22,546	4.9	3,156.6	13.2	402.7	22.4	2.9
100-200	3,070	0.8	119.1	7.3	118.3	115.9	115.1	13,444	2.9	3,520.4	14.7	782.4	30.8	6.8
200-400	1,469	0.4	109.9	6.7	233.9	122.3	260.3	5,528	1.2	2,572.2	10.7	1,545.1	22.3	13.4
400-800	663	0.2	92.3	5.6	447.9	128.5	623.6	2,038	0.4	1,708.3	7.1	3,007.9	22.2	39.0
800-1,600	264	0.1	77.8	4.7	900.8	114.4	1,325.0	816	0.2	1,342.4	5.6	6,039.3	25.0	112.6
1,600-3,200	145	0.0	86.8	5.3	1,770.4	121.8	2,485.6	460	0.1	1,633.2	6.8	11,907.5	35.8	261.0
3,200-6,400	66	0.0	88.1	5.4	3,950.0	92.9	4,167.6	247	0.1	1,913.3	8.0	22,917.6	46.1	552.0
6,400-12,800	47	0.0	112.4	6.8	7,428.9	132.1	8,729.2	51	0.0	725.3	3.0	46,468.5	9.9	635.0
> 12,800	30	0.0	176.5	10.7	18,162.2	136.8	14,083.1	9	0.0	227.5	0.9	84,081.9	3.3	1,204.3
Total	**363,459**	**100.0**	**1,642.3**	**100.0**	**12.9**	**1,614.4**	**12.7**	**461,388**	**100.0**	**23,959.1**	**100.0**	**148.5**	**283.2**	**1.8**

Table B-25: Federal Gulf 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010a)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (Mbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (MMcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (MMcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (Mbbl)	Oil Rate per Well (bbl/Day)
0-1	46	1.5	3.1	0.0	0.3	4.8	0.4	116	4.4	52.2	0.0	1.9	0.7	0.0
1-2	23	0.8	6.5	0.0	1.2	10.2	1.9	55	2.1	112.1	0.0	8.2	1.7	0.1
2-4	40	1.3	30.4	0.0	2.5	43.0	3.5	70	2.7	278.2	0.0	15.8	4.2	0.2
4-6	37	1.2	41.6	0.0	4.0	71.0	6.8	74	2.8	538.6	0.0	27.4	8.1	0.4
6-8	43	1.4	66.9	0.0	5.4	108.4	8.8	51	1.9	499.7	0.0	37.8	8.2	0.6
8-10	46	1.5	101.6	0.0	7.0	169.0	11.7	43	1.6	609.0	0.0	50.0	6.4	0.5
10-12	32	1.1	89.2	0.0	9.2	111.5	11.5	35	1.3	547.3	0.0	56.6	14.5	1.5
12-15	65	2.2	229.0	0.0	11.3	267.8	13.2	51	1.9	1,041.6	0.1	69.9	28.1	1.9
15-20	99	3.3	448.9	0.1	14.1	676.8	21.2	89	3.4	2,557.3	0.1	93.8	43.2	1.6
20-25	101	3.4	625.5	0.1	18.6	792.3	23.5	84	3.2	3,023.3	0.2	121.1	56.3	2.3
25-30	111	3.7	856.6	0.2	23.1	937.8	25.3	77	2.9	3,140.6	0.2	146.8	59.5	2.8
30-40	216	7.2	2,107.2	0.4	28.5	2,821.7	38.2	126	4.8	7,456.0	0.4	191.8	109.5	2.8
40-50	189	6.3	2,403.6	0.4	37.1	2,952.2	45.6	108	4.1	7,788.0	0.4	240.3	175.6	5.4
50-100	638	21.3	13,471.4	2.5	60.5	16,722.2	75.1	351	13.3	42,876.5	2.3	394.8	718.7	6.6
100-200	506	16.9	21,060.9	3.9	118.8	23,817.1	134.4	388	14.7	99,838.2	5.3	815.0	1,272.4	10.4
200-400	303	10.1	23,902.4	4.4	234.2	27,232.1	266.9	357	13.5	171,637.2	9.1	1,587.1	2,113.7	19.5
400-800	157	5.2	24,319.8	4.5	465.6	28,928.2	553.8	281	10.6	267,687.1	14.2	3,139.7	3,352.2	39.3
800-1,600	124	4.1	37,018.6	6.8	911.9	51,361.6	1,265.2	155	5.9	297,842.7	15.8	6,179.4	5,209.8	108.1
1,600-3,200	86	2.9	53,804.6	9.9	1,901.4	73,151.5	2,585.1	72	2.7	281,825.9	15.0	12,283.7	5,179.9	225.8
3,200-6,400	58	1.9	79,016.7	14.5	4,001.7	81,878.3	4,146.6	34	1.3	259,606.8	13.8	24,584.0	4,941.2	467.9
6,400-12,800	45	1.5	107,626.0	19.8	7,472.5	126,500.1	8,782.9	16	0.6	234,073.5	12.4	53,797.6	909.8	209.1
> 12,800	30	1.0	176,482.4	32.5	18,162.2	136,845.3	14,083.1	8	0.3	200,795.6	10.7	85,773.4	2,324.5	992.9
Total	**2,995**	**100.0**	**543,712.9**	**100.0**	**541.3**	**575,403.0**	**572.8**	**2,641**	**100.0**	**1,883,827.2**	**100.0**	**2,396.7**	**26,538.1**	**33.8**

Table B-26: U.S. 2009 Distribution of Onshore Gas Wells (EIA, 2010a, 2010b)

Prod. Rate Bracket (BOE/day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/day)	Gas Energy Equivalent (MMBtu/day)	Oil Energy Equivalent (MMBtu/day)	% of Energy from Gas	Adjusted Gas Rate per Well, (Mcf/Day)[1]
0-1	90,889	19.8%	73.4	0.3%	2.2	0.7	0.0	2.3	0.1	94.9%	2.3
1-2	44,979	9.8%	131.0	0.6%	8.0	1.3	0.1	8.2	0.5	94.7%	8.4
2-4	60,860	13.3%	358.0	1.6%	16.1	3.6	0.2	16.6	0.9	94.6%	17.0
4-6	42,935	9.4%	427.9	1.9%	27.3	4.4	0.3	28.0	1.6	94.5%	29.0
6-8	32,513	7.1%	457.3	2.1%	38.5	4.5	0.4	39.6	2.2	94.7%	41.0
8-10	24,786	5.4%	450.5	2.0%	49.8	4.3	0.5	51.1	2.8	94.9%	52.0
10-12	18,932	4.1%	420.0	1.9%	60.8	4.1	0.6	62.4	3.4	94.8%	64.0
12-15	21,667	4.7%	590.1	2.7%	74.6	5.7	0.7	76.6	4.2	94.9%	79.0
15-20	23,885	5.2%	838.7	3.8%	96.2	7.7	0.9	98.8	5.1	95.1%	101.0
20-25	16,455	3.6%	741.2	3.4%	123.0	7.4	1.2	127.0	7.0	94.6%	130.0
25-30	11,561	2.5%	641.8	2.9%	152.0	5.0	1.2	156.0	7.0	95.8%	159.0
30-40	15,957	3.5%	1,114.8	5.1%	191.0	9.4	1.6	197.0	9.0	95.5%	201.0
40-50	9,851	2.1%	887.8	4.0%	247.0	6.9	1.9	254.0	11.0	95.8%	258.0
50-100	22,195	4.8%	3,113.7	14.1%	384.0	21.7	2.7	395.0	16.0	96.2%	399.0
100-200	13,056	2.8%	3,420.6	15.5%	718.0	29.5	6.2	737.0	36.0	95.4%	753.0
200-400	5,171	1.1%	2,400.6	10.9%	1,272.0	20.2	10.7	1,306.0	62.0	95.5%	1,332.0
400-800	1,757	0.4%	1,440.6	6.5%	2,246.0	18.9	29.4	2,307.0	170.0	93.1%	2,412.0
800-1,600	661	0.1%	1,044.6	4.7%	4,330.0	19.8	82.0	4,446.0	476.0	90.3%	4,793.0
1,600-3,200	388	0.1%	1,351.4	6.1%	9,542.0	30.6	216.0	9,800.0	1,254.0	88.7%	10,763.0
3,200-6,400	213	0.0%	1,653.7	7.5%	21,271.0	41.2	529.0	21,845.0	3,071.0	87.7%	24,261.0
6,400-12,800	35	0.0%	491.2	2.2%	38,452.0	9.0	704.0	39,490.0	4,082.0	90.6%	42,427.0
> 12,800	1	0.0%	26.7	0.1%	73,163.0	1.0	2,673.0	75,138.0	15,501.0	82.9%	88,256.0
Total	**458,747**	**100.0%**	**22,075.4**	**100.0%**	**132.0**	**256.8**	**1.5**	**135.0**	**8.9**	**93.8%**	**140.0**

[1] Adjusted by energy-based co-product allocation

Co-product Allocation of Oil

The EIA data also shows that gas wells produce a small share of oil. On an energy basis, oil comprises approximately 3.8 to 17 percent of gas well production, depending on the production rate bracket. Using energy-based, co-product allocation, it is necessary to scale the production rates of the gas wells so they are representative of 100 percent gas production.

For example, a gas well that has daily production rates of 718 Mcf of natural gas and 6.2 barrels of oil has a total daily production of 773 MMBtu of energy. This energy equivalency is calculated using heating values of 1,027 Btu/cf for natural gas and 5.8 MMBtu/bbl for oil. If expressed solely on and energy-equivalent basis of natural gas, 773 MMBtu of energy is equal to 753 Mcf of natural gas. Thus, in this instance, accounting for the co-production of oil increases the nominal production rate of the gas well from 718 Mcf/day to 752 Mcf/day. Note that this nominal rate of 752 Mcf/day does not represent the actual gas produced by the well, but is an LCA accounting method that uses the relative energies of produced oil and natural gas to scale the gas production rate so it is representative of a well that produces only natural gas.

Selection of Representative Production Brackets

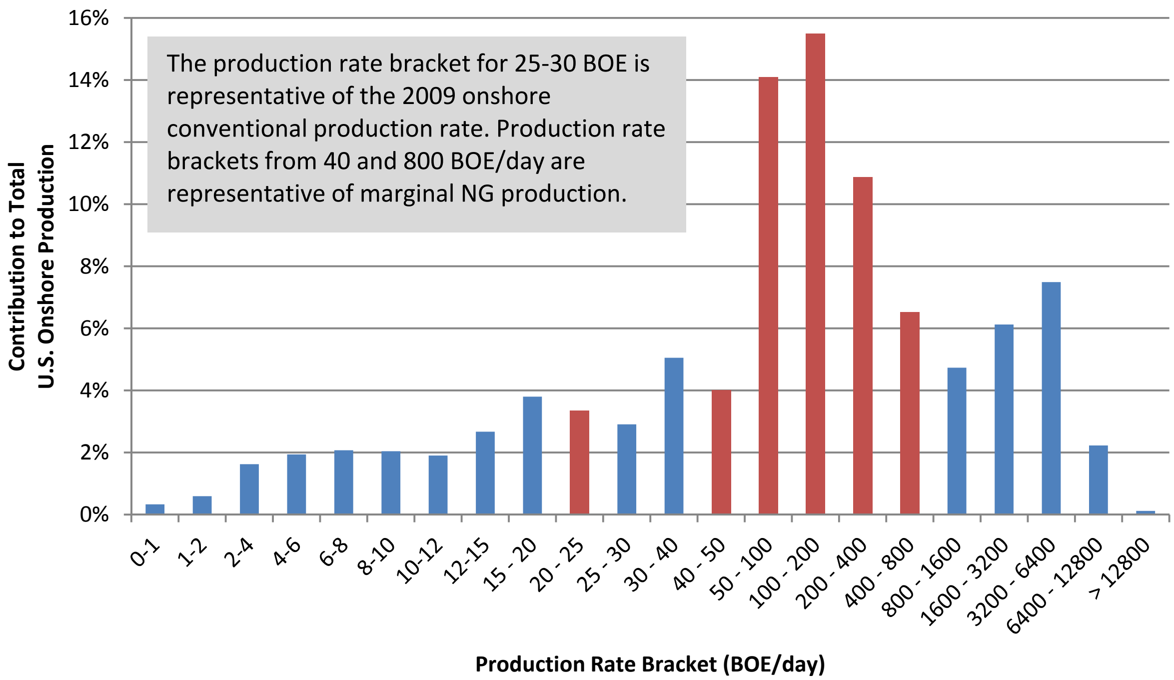
The production rates of onshore conventional natural gas wells vary widely and are a function of reservoir properties, extraction technology, and age. As shown by the EIA data, the production rates of onshore gas wells range from less than 1 BOE/day to more than 12,800 BOE/day. There are not enough data to determine the split between conventional and unconventional wells within each production rate bracket; however, the total production of each bracket and the production rates of unconventional wells can be used to determine the most likely production rates for onshore conventional natural gas. The distribution of gas wells by total gas produced is shown in **Figure B-2**.

The production categories in **Table B-26** include a large population of wells in the lowest production rate bracket; 19.8 percent of U.S. onshore natural gas wells produce less than one BOE per day. Similarly, the production rate bracket for 1 - 2 BOE/day includes 9.8 percent of natural gas wells, the production rate bracket for 2 - 4 BOE/day includes 13.3 percent of natural gas wells, and the production rate bracket for 4 - 6 BOE/day includes 9.4 percent of natural gas wells. While these four production rate brackets account for 52 percent of the total count of natural gas wells, they account for only 4.5 percent of total natural gas production.

The average production rate for conventional onshore natural gas wells in 2009 was 66 Mcf per day. This production rate was calculated by dividing the amount of onshore conventional natural gas that was produced in 2009 by the total number of onshore conventional natural gas wells in 2009.

The marginal production rate for conventional onshore natural gas was calculated by selecting the most productive region of the production rate brackets. The production rate brackets that include 40 to 800 BOE/day represent 51 percent of total onshore natural gas production. The average production rate of this range of wells is 592 Mcf/day.

Figure B-2: Distribution of Onshore Natural Gas Wells



B.2 Raw Material Acquisition: Coal

Raw material extraction for coal incorporates extraction profiles for coal derived from the PRB, where sub-bituminous, low-rank coal extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 coal seam, where bituminous coal is extracted from approximately 2 to 15 foot seams via underground longwall and continuous mining. Each modeling approach is described below.

Powder River Basin Coal

The PRB coal-producing region consists of counties in two states – Big Horn, Custer, Powder River, Rosebud, and Treasure in Montana, and Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, and Weston in Wyoming (EIA, 2009). PRB coal is advantageous in comparison to bituminous coals in that it has lower ash and sulfur content. However, PRB coal also has a lower heating value than higher rank coals (Clyde Bergemann, 2005). In 2007, there were 17 surface mines extracting PRB coal, which produced over 479 million short tons (EIA, 2009).

PRB coal is modeled using modern mining methods in practice at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008), Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008), Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008), and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (National Mining Association, 2009).

Equipment and Mine Site

Much of the equipment utilized for surface coal mining in the PRB is very large. GHG emissions that result from the production of construction materials required for coal extraction were quantified for the following equipment, within the model: track loader (10 pieces at 26,373 kg each); rotary drill (3 pieces at 113,400 kg each); walking dragline (3 pieces at 7,146,468 kg each); electric mining shovel (10 pieces at 1,256,728 kg each); mining truck (11 pieces at 278,690 kg each); coal crusher (1 piece at 115,212 kg); conveyor (1 piece at 1,064,000 kg); and loading silo (6 pieces at 10,909,569 kg each).

Coal seams are located relatively close to the ground surface in the PRB such that large-scale surface mining is common. The coal seam ranges in thickness from 42 to 184 feet thick (EPA, 2004a). Before overburden drilling and cast blasting can be carried out, topsoil and unconsolidated overburden must be removed from the consolidated overburden that is to be blasted. These operations use both truck and shovel operations and bulldozing to move these materials to a nearby stockpile location so that they can be used in post-mining site reclamation. Estimates are made for topsoil/overburden operations based on requirements reported in the Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002) for a hypothetical western surface coal mine.

Overburden Blasting and Removal

Blast holes are drilled into overburden for subsequent ammonium nitrate and fuel oil packing and detonation using large rotary drills. Drills use electricity to drill 220-270 millimeter diameter holes through sandstone, siltstone, mudstone and carbonaceous shale that make up the overburden. Typically this overburden contains water, which controls particulate emission associated with drilling activities. For the purposes of this assessment it is assumed that drilling operations produce no direct emissions. Electricity requirements for drilling are taken from the U.S. DOE report Mining Industry for the Future: Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002).

Cast blasting is a blasting technique that was developed relatively recently, and has found broad application in large surface mines. Cast blasting comminutes (breaks into fragments/particles) overburden, and also moves an estimated 25-35 percent (modeled at 30 percent) of the blasted overburden to the target fill location (Mining Technology, 2007). The model assumes that blasting uses ammonium nitrate and fuel oil explosives with a powder factor[1] of 300 g per m^3 of overburden blasted (SME, 1990), and GHG emissions associated with explosive production and the blasting process are included in the model, based on EPA’s AP-42 report (EPA, 1995).

Overburden removal is achieved primarily through dragline operations, with the remainder moved using large electric shovels. Dragline excavation systems are among the largest on-land machines, and utilize a large bucket suspended from a boom, where the bucket is scraped along the ground to fill the bucket. The bucket is then emptied at a nearby fill location. Electricity requirements for dragline operation combined with other on site operations, were estimated based on electricity usage at the North Antelope Rochelle Mine, to be approximately 971 kWh per 1000 tons of coal (Peabody, 2006). During this time dragline operation accounted for approximately 50% of the overburden energy.

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[1] Powder factor refers to the mass of explosive needed to blast a given mass of material.

Coal Recovery

Following overburden removal, coal is extracted using truck and shovel-type operations. Because of the large scale of operations, large electric mining shovels (Bucyrus 495 High Performance Series) are assumed to be employed, with a bucket capacity of 120 tons, alongside 320-400 ton capacity mining trucks (Bucyrus International Inc., 2008).

The amount of coal that could be moved by a single shovel per year was determined by using data for the Black Thunder and Cordero Rojo coal mines (Mining Technology, 2007). A coal hauling distance of two miles is assumed, with a round-trip distance of four miles, based on evaluation of satellite imagery of mining operations. The extracted coal is ground and crushed to the necessary size for transportation. It is assumed that the coal does not require cleaning before leaving the mine site. The crushed coal is carried from the preparation facility to a loading silo by an overland conveyor belt. From the loading silo, the coal is loaded into railcars for transportation.

Coal Bed Methane Emissions

During coal acquisition, methane is released during both the coal extraction and post-mining coal preparation activities. While the PRB has relatively low specific methane content, the large thickness of the coal deposit (80 feet thick or more in many areas) has a large methane content per square foot of surface area. As a result the PRB has recently begun to be exploited on a large scale. Extraction of coal bed methane, prior to mining of the coal seam, results in a net reduction of the total amount of coal bed methane that is emitted to the atmosphere, since extracted methane is typically sold into the natural gas market, and eventually combusted.

For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on recent data available from the EPA, coal bed methane emissions for surface mining, including the PRB, are expected to range from 8 to 98 standard cubic feet per ton (cf/ton) of produced coal, with a typical value of 51 cf/ton (EPA, 2011b).

Illinois No. 6 Coal

Illinois No. 6 coal is part of the Herrin Coal, and is a bituminous coal that is found in seams that typically range from about 2 to 15 feet in thickness, and is found in the southern and eastern regions of Illinois and surrounding areas. Illinois No. 6 coal is commonly extracted via underground mining techniques, including continuous mining and longwall mining. Illinois No. 6 coal seams may contain relatively high levels of mineral sediments or other materials, and therefore require coal cleaning (beneficiation) at the mine site. The following sections describe the unit processes modeled for Illinois No. 6 coal mining.

Equipment and Mine Site

Extraction of Illinois No. 6 coal requires several types of major equipment and mining components, in order to operate the coal mine. The following components were modeled for use during underground mining operations: site paving and concrete, conveyor belt, stacker/reclaimer, crusher, coal cleaning, silo, wastewater treatment, continuous miner, longwall mining systems (including shear head, roof supports, armored force conveyor, stage loader, and mobile belt tailpiece), and shuttle car systems with replacement. Overall, when considering materials requirements for the construction of these systems, the material inputs values shown in **Table B-27** were required for mine and mining system construction, on a per lb. of coal output basis. GHG emissions associated with the production of these materials were incorporated into the model and accounted for as construction related emissions.

Table B-27: Construction Materials Required for Illinois No. 6 Coal Mining

Construction Material	Amount	Units
Cold-Rolled Steel	1.47E-05	lb/lb Coal Produced
Hot-dip Galvanized Steel	1.52E-06	lb/lb Coal Produced
Rubber	4.45E-07	lb/lb Coal Produced
Steel Plate	1.80E-04	lb/lb Coal Produced
Concrete	6.06E-05	lb/lb Coal Produced
Rebar	1.41E-06	lb/lb Coal Produced
Polyvinylchloride Pipe	1.30E-07	lb/lb Coal Produced
Steel, Stainless, 316	6.77E-08	lb/lb Coal Produced
Stainless Steel Cold Roll 431	6.77E-08	lb/lb Coal Produced
Cast Iron	3.38E-07	lb/lb Coal Produced
Copper Mix	8.11E-09	lb/lb Coal Produced
Asphalt	1.11E-03	lb/lb Coal Produced

Coal Mine Operations

Operations of the coal mine were based on operation of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines, as relevant.

Electricity is the main source of energy for coal mine operations. Electricity use for this model was estimated based on previous estimates made by EPA for electricity use for underground mining and coal cleaning at the Galatia Mine (EPA, 2008). The life cycle profile for electricity use is based on Egrid2007. The Emissions and Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes for electric power systems (EPA, 2010).

Although no Galatia Mine data were found that estimated the diesel fuel used during mining operations, it was assumed that some diesel would be used to operate trucks for moving materials, workers, and other secondary on-site operations. Therefore, diesel use was estimated for the Galatia Mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Census Bureau, 2004). Emissions of GHGs were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (EPA, 2004b).

Coal Bed Methane

During the acquisition of Illinois No. 6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Illinois No. 6 coal seams are not nearly as thick as PRB coals, and as a result are less commonly utilized as a resource for coal bed methane extraction. Instead, methane capture may be applied during the coal extraction process. Based on recent data available from the EPA, coal bed methane emissions for underground mining, including mining within the Illinois No. 6 coal seam, are expected to range from 360 to 500 cf/ton of produced coal, with a nominal value of 422 cf/ton (EPA, 2011b). It is assumed that no methane capture is applied for Illinois No. 6 coal.

B.3 Raw Material Transport: Natural Gas

The boundary of raw material transport begins with receipt of processed natural gas at the extraction site and ends with the delivery of natural gas to an energy conversion facility. Methane emissions from pipeline operations are a function of pipeline distance. This analysis uses a pipeline transport distance of 604 miles (971.4 km), which is the average distance for natural gas pipeline transmission in the U.S. The data sources and assumptions for calculating the greenhouse gas emissions from construction and operation of natural gas transmission pipelines are discussed below.

Pipeline Construction and Decommissioning

Carbon steel is the primary material used in the construction of natural gas pipelines. The mass of pipeline per unit length was determined using an online calculator (Steel Pipes & Tubes, 2009). The weight of valves and fittings were estimated at an additional 10 percent of the total pipeline weight. The pipeline was assumed to have a life of 30 years. The mass of pipeline construction per kilogram of natural gas was determined by dividing the total pipeline weight by the total natural gas flow through the pipeline for a 30-year period.

The decommissioning of a natural gas pipeline involves cleaning and capping activities. This analysis assumes that the decommissioning of a natural gas pipeline incurs 10 percent of the energy requirements and emissions as the original installation of the pipeline.

Pipeline Operations

The U.S. has an extensive natural gas pipeline network that connects natural gas supplies and markets. Compressor stations are necessary every 50 to 100 miles along the natural gas transmission pipelines in order to boost the pressure of the natural gas. Compressor stations consist of centrifugal and reciprocating compressors. Most natural gas compressors are powered by natural gas, but, when electricity is available, electrically-powered compressors are used.

A 2008 paper published by the Interstate Natural Gas Association of America provides data from its 2004 database, which shows that the U.S. pipeline transmission network has 5,400 reciprocating compressors and over 1,000 gas turbine compressors (Hedman, 2008). Further, based on written communication from El Paso Pipeline Group, approximately three percent of transmission compressors are electrically driven (George, 2011). El Paso Pipeline Group has the highest transmission capacity of all natural gas pipeline companies in the U.S., and it is thus assumed that the share of electrically-powered compressors in their fleet is representative of the entire natural gas transmission network. Based on written communication with El Paso Pipeline Group (George, 2011), the share of compressors on the U.S. natural gas pipeline transmission network is approximately 78 percent reciprocating compressors, 19 percent turbine-powered centrifugal compressors, and 3 percent electrically-powered compressors.

The use rate of natural gas for fuel in transmission compressors was calculated from the Federal Energy Regulatory Commission (FERC) Form 2 database, which is based on an annual survey of gas producers and pipeline companies (FERC, 2010). The 28 largest pipeline companies were pulled from the FERC Form 2 database. These 28 companies represent 81 percent of NG transmission in 2008. The FERC data for 81 percent of U.S. natural gas transmission is assumed to be a representative sample of the fuel use rate of the entire transmission network. This data shows that

0.96 percent of natural gas product is consumed as compressor fuel. This fuel use rate was converted to a basis of kg of natural gas consumed per kg of natural gas transported by multiplying it by the total natural gas delivered by the transmission network in 2008 (EIA, 2011) and dividing it by the annual tonne-km of pipeline transmission in the U.S. (Dennis, 2005). The total delivery of natural gas in 2008 was 21 Tcf, which is approximately 400 billion kg of natural gas. The annual transport rate for natural gas transmission was steady from 1995 through 2003, at approximately 380 billion tonne-km per year. More recent transportation data are not available, and thus this analysis assumes the same tonne-km rate for 2008 as shown from 1995 through 2003.

The air emissions from the combustion of natural gas by compressors are estimated by applying EPA emission factors to the natural gas consumption rate of the compressors (EPA, 1995). Specifically, the emission profile of gas-powered, centrifugal compressors is based on emission factors for gas turbines; the emission profile of gas-powered, reciprocating compressors is based on emission factors for 4-stroke, lean burn engines. For electrically-powered compressors, this analysis assumes that the indirect emissions are representative of the U.S. average fuel mix for electricity generation.

The average power of electrically-driven compressors for U.S. NG transmission is assumed to be the same as the average power of all compressors on the transmission network. An average compressor on the U.S. natural gas transmission network has a power rating of 14,055 horsepower (10.5 MW) and a throughput of 734 million cubic feet of natural gas per day (583,000 kg NG/hour) (EIA, 2007). Electrically-driven compressors have efficiencies of 95 percent (DOE, 1996; Hedman, 2008). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output.

In addition to air emissions from combustion processes, fugitive venting from pipeline equipment results in the methane emissions to air. The fugitive emission rate for natural gas pipeline operations is based on data published by the Bureau of Transportation Statistics (BTS) and EPA. The transport data for natural gas transmission is based on ton-mileage estimates by BTS, which calculates 253 billion ton-miles of natural gas transmission in 2003 (Dennis, 2005). The 2003 data are the most recent data point in the BTS reference, and thus EPA's inventory data for the years 2000 and 2005 were interpolated to arrive at a year 2003 value of 1,985 million kg of fugitive methane emissions per year (EPA, 2011b). Dividing the EPA emission by the transport requirements and converting to metric units gives 5.37E-06 kg/kg-km.

Calculation of Average Natural Gas Transmission Distance

The average pipeline distance for natural gas transport is determined by balancing national emission inventory (EPA, 2011b) and natural gas consumption data (EIA, 2011) with NETL’s unit process emission factor for fugitive methane emissions from pipeline operations. **Equation 5** shows the national inventory and consumption data on the left-hand side and NETL’s emission factor for fugitive methane on the right-hand side.

$$\frac{E_{methane}}{NG_{consumption}} = d * EF_{methane} \qquad \textbf{(Equation 5)}$$

Where,

$E_{methane}$ = Total pipeline fugitive methane emissions (default = 2,115E+06 kg CH_4/yr)
$NG_{consumption}$ = consumption of natural gas (default = 21.84 MMBtu/yr)
$EF_{methane}$ = Emission factor for fugitive methane (default =9.97E-05 kg CH_4/MMBtu-km)

The default value for total fugitive emissions of methane from pipeline transmission are based on the 2009 national inventory emissions for natural gas transmission and storage reported by EPA (EPA, 2011b). The value reported by EPA is 2,115 Gg CH_4/yr, which is equal to 2,115 million kg CH_4/yr.

The default value for annual natural gas consumption is based on annual EIA statistics for natural gas production and consumption (EIA, 2011). The volume of natural gas transported by pipeline is 21.26 Tcf/year. This value is the midpoint of the volume of processed natural gas injected to the pipeline transmission network and the volume of natural gas delivered to consumers. In 2009 the volume of natural gas injected to the natural gas transmission network by NG processing plants was 21.56 Tcf; this volume was calculated by subtracting the natural gas consumption at the extraction and processing sites (1.28 Tcf) from total annual consumption (22.84 Tcf) (EIA, 2011). In 2009 the volume of natural gas delivered to consumers was 20.97 Tcf (EIA, 2011). The average volume of natural gas transmission was converted to an energy basis using an energy density of 1,027 Btu/cf; 21.26 Tcf/year is equivalent to 21.84 E+09 MMBtu. Converting to an energy basis (using a density of 0.042 lbs./cf and energy content of 1,027 Btu/cf) gives 21.84 billion MMBtu.

For **Equation 5** it is necessary to convert the emission factor for fugitive emissions from pipeline operations (calculated above) to an energy basis so that it can be factored with the annual consumption data for natural gas. The emission factor used by the pipeline unit process is 5.37E-06 kg/kg-km. Converting to an energy basis (using the conversion factors of 0.042 lb./cf NG and 1,027 Btu/cf) results in an emission factor of 9.97E-05 kg CH_4/MMBtu-km.

The unknown *d* in **Equation 5** is the distance (km) that reconciles NETL's unit process with the national level data. Solving for *d* gives the following equation:

$$d = \frac{E_{methane}}{NG_{consumption} * EF_{methane}} \qquad \textbf{(Equation 6)}$$

Applying the default values to **Equation 6** gives a distance of 971 km (604 miles), as shown in **Equation 7**.

$$d = \frac{2{,}115 \times 10^6 kg\ CH_4/yr}{(21.84 \times 10^9 MMBtu/yr)(9.97 \times 10^{-5} kgCH_4/MMBtu\ km)} = 971\ km \qquad \textbf{(Equation 7)}$$

The pipeline transport of natural gas results in losses of natural gas product to two activities: (1) fugitive emissions and (2) natural gas used as fuel in pipeline compressors. Based on the data and assumptions of this unit process, the transmission of natural gas a distance of 971 km results in a 1.45 percent loss of natural gas product (1.0148 kg of natural gas are injected into the pipeline to deliver 1.0 kg of natural gas to the consumer). The annual data for natural gas production and consumption (EIA, 2011) show a 2.81 percent loss of natural gas for transmission and distribution (natural gas processing plants produce 21.56 Tcf of natural gas and 20.97 Tcf of natural gas are delivered to consumers). The 2.81 percentage loss factor includes pipeline *distribution* in addition to pipeline transmission, and thus it is expected for the transmission losses (1.45 percent) to be lower than the transmission and distribution loss (2.81 percent).

The default values for key variables for NETL's model of natural gas pipeline transmission are shown in the **Table B-28**.

Table B-28: Natural Gas Transport to Large End User

Natural Gas Emissions and Transmission Infrastructure	Units	Value
Pipeline Transport Distance (National Average)	Miles	604
Distance Between Compressor Stations	Miles	75
Compression, Gas-powered, Reciprocating Engine	Percent	78%
Compression, Gas-powered, Centrifugal Engine	Percent	19%
Compression, Electrical, Centrifugal Engine	Percent	3%

B.4 Raw Material Transport: Coal

Train transport was modeled for the transport of both PRB and Illinois No. 6 coal from mining sites to energy conversion facilities. Mined coal is presumed to be transported by rail from PRB and Illinois No. 6 coal mine sources, in support of electricity production. Coal is assumed to be transported via unit train, where a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400 horsepower diesel engine (GE Transportation, 2010) and each car has a 100-ton coal capacity (NETL, 2007).

GHG emissions for train transport are evaluated based on typical diesel combustion emissions for a locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. It is assumed that the majority of the railway connecting the coal mine and the energy conversion facility is existing infrastructure. An assumed 25-mile rail spur was constructed between the energy conversion facility and the primary railway.

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Appendix C:
Data for Natural Gas Power

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C.1 Natural Gas Power Plant Operation

This analysis includes four types of natural gas power systems: NGCC, NGCC with CCS, GTSC, and fleet baseload natural gas power. The environmental performance of NGCC systems has been documented in NETL's LCA of a NGCC power (NETL, 2010d) as well as NETL's bituminous baseline report (NETL, 2010a) and is not repeated in this appendix. The environmental performance of fleet baseload natural gas power is based on the efficiency of existing natural gas power plants and does not account for environmental emissions other than GHG emissions; the key data behind the modeling of fleet baseload natural gas power are provided in the main body of this report. The environmental performance of a GTSC power plant, however, is not documented elsewhere. The operating characteristics of the GTSC power plant are presented below.

The GTSC plant uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators (CTGs). The performance of the GTSC plant was adapted from the NETL baseline of NGCC power by considering only the streams that enter and exit the combustion turbines/generators and do not account for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW. **Table C-1** shows the total, net, and auxiliary power of the NGCC plant and the assumptions for determining the power output of the GTSC plant.

The emission profile for the GTSC plant is identical to the emission profile for the NGCC plant. However, due to the relatively lower power output of the GTSC plant, the emissions per MWh of electricity generation are higher for the GTSC plant than for the NGCC plant. The emission of CO_2 and NO_X from the GTSC plant is calculated by scaling the NGCC CO_2 and NO_X emissions by the relative power outputs of the NGCC and GTSC systems.

The emission profile shown in the NETL baseline (NETL, 2010a) does not include a comprehensive list of criteria air pollutants and other air emissions of concern. In particular, CO emissions are not reported in the NETL baseline. Factors from EPA's AP-42 documentation (EPA, 1995) were used to calculate CO emissions from the GTSC plant. This calculation included the assumption that CO emissions from natural gas-fired turbines are not controlled.

The NETL baseline (NETL, 2010a) shows negligible mercury emissions from the NGCC plant; thus, this analysis assumes that the GTSC plant produces negligible mercury emissions. Additional searches on the EPA's National Emissions Inventory confirmed that natural gas power plants do not produce significant mercury emissions. Therefore, no mercury emissions are estimated for the GTSC plant. Similarly, this analysis assumes that negligible lead emissions are produced from natural gas combustion in a GTSC plant.

Ammonia emissions to air are not inventoried in the baseline report (NETL, 2010a). However, due to the use of selective catalytic reduction (SCR) for NO_X control, some ammonia is emitted. The baseline report states a 10 ppmv ammonia slip rate (through the stack) at the end of the catalyst life. Further investigation showed that as the SCR catalyst degrades, the ammonia slip increases; once new catalyst is added to the system the slip rate goes to zero. The following parameters were used to simplify the calculation of an ammonia emission rate: a 10 ppmv rate is the maximum slip rate at the end of the catalyst life, each layer (in the two layer catalyst system) has a two year lifetime, and the slip rate is linear to catalyst activity. Using the available data, a 5 ppmv average slip rate was calculated for the lifetime of the plant.

Table C-1: Comparison of NGCC and GTSC Power Plants

Performance Characteristics	NGCC	GTSC	NGCC to GTSC Adaptation Method
Gas Turbine Power	362,200	362,200	No adaptation necessary
Steam Turbine Power	202,500	0	The GTSC plant does not have a steam cycle
TOTAL POWER, kWe	**564,700**	**362,200**	Sum of gas and steam turbine power
AUXILIARY LOAD SUMMARY, kWe			
Condensate Pumps	170	0	The GTSC plant does not have a steam cycle
Boiler Feedwater Pumps	2,720	0	The GTSC plant does not have a steam cycle
Amine System Auxiliaries	0	0	No adaptation necessary
CO_2 Compression	0	0	No adaptation necessary
Circulating Water Pump	2,300	0	The GTSC plant does not have a steam cycle
Ground Water Pumps	210	0	The GTSC plant does not have a steam cycle
Cooling Tower Fans	1,190	0	The GTSC plant does not have a steam cycle
SCR	10	10	No adaptation necessary; NO_X is from the gas turbine
Gas Turbine Auxiliaries	700	700	No adaptation necessary
Steam Turbine Auxiliaries	100	0	The GTSC plant does not have a steam cycle
Miscellaneous Balance of Plant	500	500	Miscellaneous systems are the same for NGCC and GTSC
Transformer Losses	1,720	1103	Transformer losses are directly proportional to power
TOTAL AUXILIARIES, kWe	**9,620**	**2,316**	
NET POWER, kWe	**555,080**	**359,884**	
Net Plant Efficiency (HHV)	50.20%	30.04%	Net Plant Efficiency = (Net Power/Thermal HHV Input)*100%
Net Plant Efficiency (LHV)	55.70%	33.32%	Net Plant Efficiency = (Net Power/Thermal LHV Input)*100%
Net Plant Heat Rate (HHV), kJ/kWh	7,172	11,983	Net Plant Heat Rate (HHV) = (3600 kJ/kWh)/Net Plant Efficiency (HHV)
Net Plant Heat Rate (LHV), kJ/kWh	6,466	10,804	Net Plant Heat Rate (LHV) = (3600 kJ/kWh)/Net Plant Efficiency (LHV)
CONSUMABLES			
Natural Gas Feed Flow, kg/hr	75,901	75,901	No adaptation necessary
Thermal Input (HHV), kW_{th}	1,105,812	1,105,812	No adaptation necessary
Thermal Input (LHV) , kW_{th}	997,032	997,032	No adaptation necessary
Raw Water Withdrawal, m^3/min	8.9	0	GTSC plant does not have process water requirements
Raw Water Consumption, ^{3}/min	6.9	0	GTSC plant does not have process water requirements

The GTSC system does not have a steam cycle, nor does it require process cooling water. Thus, this analysis assumes that the GTSC does not withdraw or consume water. Furthermore, no emissions to water are generated from GTSC operations.

A variable capacity factor is modeled for the GTSC system. The GTSC operation data used for this analysis is not dependent on the capacity factor, but this capacity factor is used for apportioning the construction and installation requirements of the GTSC plant to the basis of 1 MWh of electricity generation.

There is evidence that the thermal efficiency (MMBtu natural gas input per MWh electricity output) of the gas turbine goes down as output is turned down. Further, oxidation efficiency may be reduced, increasing the rate of CO relative to CO_2, and NO_X emissions may increase. The effect that GTSC operating characteristics have on these emissions is not accounted for in this analysis.

The energy and material flows for a GTSC plant are shown in **Table C-2**. These flows account for only the direct inputs and outputs during the operation of a GTSC plant.

Table C-2: Direct Energy and Material Flows for a GTSC Plant

Inputs	Value	Units
Natural Gas	210.9	kg
Water (Surface Water)	0	kg
Water (Ground Water)	0	kg
Outputs	**Value**	**Units**
Electricity	1	MWh
Carbon Dioxide (To Air)	560.0	kg
Nitrogen Oxides (To Air)	0.0429	kg
Carbon Monoxide (To Air)	0.423	kg
Ammonia (To Air)	0.0269	kg

Appendix C: References

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Appendix D:
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Table D-1: Upstream Greenhouse Gas Inventory Results for Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Average Gas	CO_2	5.78E+00	1.10E+00	6.88E+00	2.62E+00	4.97E-01	3.12E+00	2.48E+00	4.71E-01	2.96E+00	2.97E-06	5.63E-07	3.53E-06
	N_2O	1.87E-04	1.37E-06	1.88E-04	8.46E-05	6.21E-07	8.53E-05	8.02E-05	5.89E-07	8.08E-05	9.58E-11	7.03E-13	9.65E-11
	CH_4	5.27E-01	2.14E-01	7.40E-01	2.39E-01	9.69E-02	3.36E-01	2.26E-01	9.18E-02	3.18E-01	2.70E-07	1.10E-07	3.80E-07
	CO_2e (20-year)	4.37E+01	1.65E+01	6.02E+01	1.98E+01	7.47E+00	2.73E+01	1.88E+01	7.08E+00	2.59E+01	2.25E-05	8.46E-06	3.09E-05
	CO_2e (100-year)	1.90E+01	6.44E+00	2.54E+01	8.62E+00	2.92E+00	1.15E+01	8.17E+00	2.77E+00	1.09E+01	9.76E-06	3.30E-06	1.31E-05
	CO_2e (500-year)	9.81E+00	2.72E+00	1.25E+01	4.45E+00	1.23E+00	5.68E+00	4.22E+00	1.17E+00	5.39E+00	5.04E-06	1.40E-06	6.43E-06
Conventional Gas	CO_2	6.07E+00	1.10E+00	7.17E+00	2.75E+00	4.97E-01	3.25E+00	2.61E+00	4.71E-01	3.08E+00	3.12E-06	5.63E-07	3.68E-06
	N_2O	2.07E-04	1.37E-06	2.08E-04	9.37E-05	6.21E-07	9.43E-05	8.88E-05	5.89E-07	8.94E-05	1.06E-10	7.03E-13	1.07E-10
	CH_4	4.26E-01	2.14E-01	6.40E-01	1.93E-01	9.69E-02	2.90E-01	1.83E-01	9.18E-02	2.75E-01	2.19E-07	1.10E-07	3.28E-07
	CO_2e (20-year)	3.68E+01	1.65E+01	5.33E+01	1.67E+01	7.47E+00	2.42E+01	1.58E+01	7.08E+00	2.29E+01	1.89E-05	8.46E-06	2.74E-05
	CO_2e (100-year)	1.68E+01	6.44E+00	2.32E+01	7.61E+00	2.92E+00	1.05E+01	7.22E+00	2.77E+00	9.98E+00	8.62E-06	3.30E-06	1.19E-05
	CO_2e (500-year)	9.34E+00	2.72E+00	1.21E+01	4.24E+00	1.23E+00	5.47E+00	4.02E+00	1.17E+00	5.19E+00	4.80E-06	1.40E-06	6.19E-06
Unconv. Gas	CO_2	5.58E+00	1.10E+00	6.68E+00	2.53E+00	4.97E-01	3.03E+00	2.40E+00	4.71E-01	2.87E+00	2.87E-06	5.63E-07	3.43E-06
	N_2O	1.73E-04	1.37E-06	1.74E-04	7.85E-05	6.21E-07	7.91E-05	7.44E-05	5.89E-07	7.50E-05	8.89E-11	7.03E-13	8.96E-11
	CH_4	5.94E-01	2.14E-01	8.08E-01	2.70E-01	9.69E-02	3.66E-01	2.56E-01	9.18E-02	3.47E-01	3.05E-07	1.10E-07	4.15E-07
	CO_2e (20-year)	4.84E+01	1.65E+01	6.49E+01	2.20E+01	7.47E+00	2.94E+01	2.08E+01	7.08E+00	2.79E+01	2.49E-05	8.46E-06	3.33E-05
	CO_2e (100-year)	2.05E+01	6.44E+00	2.69E+01	9.30E+00	2.92E+00	1.22E+01	8.81E+00	2.77E+00	1.16E+01	1.05E-05	3.30E-06	1.38E-05
	CO_2e (500-year)	1.01E+01	2.72E+00	1.28E+01	4.59E+00	1.23E+00	5.83E+00	4.35E+00	1.17E+00	5.52E+00	5.20E-06	1.40E-06	6.60E-06
Onshore Gas	CO_2	6.78E+00	1.10E+00	7.88E+00	3.08E+00	4.97E-01	3.57E+00	2.92E+00	4.71E-01	3.39E+00	3.48E-06	5.63E-07	4.05E-06
	N_2O	2.00E-04	1.37E-06	2.01E-04	9.06E-05	6.21E-07	9.12E-05	8.58E-05	5.89E-07	8.64E-05	1.03E-10	7.03E-13	1.03E-10
	CH_4	6.68E-01	2.14E-01	8.82E-01	3.03E-01	9.69E-02	4.00E-01	2.87E-01	9.18E-02	3.79E-01	3.43E-07	1.10E-07	4.53E-07
	CO_2e (20-year)	5.50E+01	1.65E+01	7.14E+01	2.49E+01	7.47E+00	3.24E+01	2.36E+01	7.08E+00	3.07E+01	2.82E-05	8.46E-06	3.67E-05
	CO_2e (100-year)	2.36E+01	6.44E+00	3.00E+01	1.07E+01	2.92E+00	1.36E+01	1.01E+01	2.77E+00	1.29E+01	1.21E-05	3.30E-06	1.54E-05
	CO_2e (500-year)	1.19E+01	2.72E+00	1.46E+01	5.39E+00	1.23E+00	6.63E+00	5.11E+00	1.17E+00	6.28E+00	6.11E-06	1.40E-06	7.50E-06

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Offshore Gas	CO_2	5.37E+00	1.10E+00	6.46E+00	2.43E+00	4.97E-01	2.93E+00	2.31E+00	4.71E-01	2.78E+00	2.76E-06	5.63E-07	3.32E-06
	N_2O	2.54E-04	1.37E-06	2.56E-04	1.15E-04	6.21E-07	1.16E-04	1.09E-04	5.89E-07	1.10E-04	1.31E-10	7.03E-13	1.31E-10
	CH_4	9.01E-02	2.14E-01	3.04E-01	4.09E-02	9.69E-02	1.38E-01	3.87E-02	9.18E-02	1.31E-01	4.63E-08	1.10E-07	1.56E-07
	CO_2e (20-year)	1.19E+01	1.65E+01	2.84E+01	5.41E+00	7.47E+00	1.29E+01	5.13E+00	7.08E+00	1.22E+01	6.12E-06	8.46E-06	1.46E-05
	CO_2e (100-year)	7.69E+00	6.44E+00	1.41E+01	3.49E+00	2.92E+00	6.41E+00	3.31E+00	2.77E+00	6.07E+00	3.95E-06	3.30E-06	7.26E-06
	CO_2e (500-year)	6.09E+00	2.72E+00	8.81E+00	2.76E+00	1.23E+00	4.00E+00	2.62E+00	1.17E+00	3.79E+00	3.13E-06	1.40E-06	4.52E-06
Assoc. Gas	CO_2	5.04E+00	1.10E+00	6.14E+00	2.29E+00	4.97E-01	2.78E+00	2.17E+00	4.71E-01	2.64E+00	2.59E-06	5.63E-07	3.15E-06
	N_2O	1.42E-04	1.37E-06	1.43E-04	6.43E-05	6.21E-07	6.49E-05	6.09E-05	5.89E-07	6.15E-05	7.27E-11	7.03E-13	7.34E-11
	CH_4	2.45E-01	2.14E-01	4.59E-01	1.11E-01	9.69E-02	2.08E-01	1.05E-01	9.18E-02	1.97E-01	1.26E-07	1.10E-07	2.36E-07
	CO_2e (20-year)	2.27E+01	1.65E+01	3.92E+01	1.03E+01	7.47E+00	1.78E+01	9.78E+00	7.08E+00	1.69E+01	1.17E-05	8.46E-06	2.01E-05
	CO_2e (100-year)	1.12E+01	6.44E+00	1.77E+01	5.09E+00	2.92E+00	8.01E+00	4.82E+00	2.77E+00	7.59E+00	5.76E-06	3.30E-06	9.06E-06
	CO_2e (500-year)	6.93E+00	2.72E+00	9.65E+00	3.14E+00	1.23E+00	4.38E+00	2.98E+00	1.17E+00	4.15E+00	3.56E-06	1.40E-06	4.95E-06
Tight Gas	CO_2	5.45E+00	1.10E+00	6.55E+00	2.47E+00	4.97E-01	2.97E+00	2.34E+00	4.71E-01	2.81E+00	2.80E-06	5.63E-07	3.36E-06
	N_2O	1.55E-04	1.37E-06	1.56E-04	7.03E-05	6.21E-07	7.09E-05	6.66E-05	5.89E-07	6.72E-05	7.96E-11	7.03E-13	8.03E-11
	CH_4	6.61E-01	2.14E-01	8.75E-01	3.00E-01	9.69E-02	3.97E-01	2.84E-01	9.18E-02	3.76E-01	3.40E-07	1.10E-07	4.49E-07
	CO_2e (20-year)	5.31E+01	1.65E+01	6.96E+01	2.41E+01	7.47E+00	3.16E+01	2.28E+01	7.08E+00	2.99E+01	2.73E-05	8.46E-06	3.57E-05
	CO_2e (100-year)	2.20E+01	6.44E+00	2.85E+01	9.99E+00	2.92E+00	1.29E+01	9.47E+00	2.77E+00	1.22E+01	1.13E-05	3.30E-06	1.46E-05
	CO_2e (500-year)	1.05E+01	2.72E+00	1.32E+01	4.76E+00	1.23E+00	6.00E+00	4.52E+00	1.17E+00	5.68E+00	5.39E-06	1.40E-06	6.79E-06
CBM Gas	CO_2	5.45E+00	1.10E+00	6.54E+00	2.47E+00	4.97E-01	2.97E+00	2.34E+00	4.71E-01	2.81E+00	2.80E-06	5.63E-07	3.36E-06
	N_2O	1.55E-04	1.37E-06	1.56E-04	7.03E-05	6.21E-07	7.09E-05	6.66E-05	5.89E-07	6.72E-05	7.96E-11	7.03E-13	8.03E-11
	CH_4	2.49E-01	2.14E-01	4.62E-01	1.13E-01	9.69E-02	2.10E-01	1.07E-01	9.18E-02	1.99E-01	1.28E-07	1.10E-07	2.37E-07
	CO_2e (20-year)	2.34E+01	1.65E+01	3.99E+01	1.06E+01	7.47E+00	1.81E+01	1.01E+01	7.08E+00	1.71E+01	1.20E-05	8.46E-06	2.05E-05
	CO_2e (100-year)	1.17E+01	6.44E+00	1.81E+01	5.31E+00	2.92E+00	8.23E+00	5.03E+00	2.77E+00	7.80E+00	6.01E-06	3.30E-06	9.32E-06
	CO_2e (500-year)	7.36E+00	2.72E+00	1.01E+01	3.34E+00	1.23E+00	4.57E+00	3.16E+00	1.17E+00	4.33E+00	3.78E-06	1.40E-06	5.18E-06
Barnett Shale Gas	CO_2	5.78E+00	1.10E+00	6.87E+00	2.62E+00	4.97E-01	3.12E+00	2.48E+00	4.71E-01	2.95E+00	2.97E-06	5.63E-07	3.53E-06
	N_2O	1.72E-04	1.37E-06	1.73E-04	7.79E-05	6.21E-07	7.85E-05	7.39E-05	5.89E-07	7.44E-05	8.82E-11	7.03E-13	8.89E-11
	CH_4	6.58E-01	2.14E-01	8.72E-01	2.99E-01	9.69E-02	3.96E-01	2.83E-01	9.18E-02	3.75E-01	3.38E-07	1.10E-07	4.48E-07
	CO_2e (20-year)	5.32E+01	1.65E+01	6.97E+01	2.41E+01	7.47E+00	3.16E+01	2.29E+01	7.08E+00	3.00E+01	2.73E-05	8.46E-06	3.58E-05
	CO_2e (100-year)	2.23E+01	6.44E+00	2.87E+01	1.01E+01	2.92E+00	1.30E+01	9.58E+00	2.77E+00	1.23E+01	1.14E-05	3.30E-06	1.47E-05
	CO_2e (500-year)	1.08E+01	2.72E+00	1.35E+01	4.90E+00	1.23E+00	6.14E+00	4.65E+00	1.17E+00	5.81E+00	5.55E-06	1.40E-06	6.95E-06

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marcellus Shale Gas	CO_2	5.85E+00	1.10E+00	6.95E+00	2.65E+00	4.97E-01	3.15E+00	2.52E+00	4.71E-01	2.99E+00	3.00E-06	5.63E-07	3.57E-06
	N_2O	4.52E-04	1.37E-06	4.53E-04	2.05E-04	6.21E-07	2.06E-04	1.94E-04	5.89E-07	1.95E-04	2.32E-10	7.03E-13	2.33E-10
	CH_4	6.35E-01	2.14E-01	8.49E-01	2.88E-01	9.69E-02	3.85E-01	2.73E-01	9.18E-02	3.65E-01	3.26E-07	1.10E-07	4.36E-07
	CO_2e (20-year)	5.17E+01	1.65E+01	6.82E+01	2.35E+01	7.47E+00	3.09E+01	2.22E+01	7.08E+00	2.93E+01	2.66E-05	8.46E-06	3.50E-05
	CO_2e (100-year)	2.19E+01	6.44E+00	2.83E+01	9.92E+00	2.92E+00	1.28E+01	9.40E+00	2.77E+00	1.22E+01	1.12E-05	3.30E-06	1.45E-05
	CO_2e (500-year)	1.07E+01	2.72E+00	1.35E+01	4.87E+00	1.23E+00	6.11E+00	4.62E+00	1.17E+00	5.79E+00	5.52E-06	1.40E-06	6.91E-06
LNG Gas	CO_2	2.93E+01	1.10E+00	3.04E+01	1.33E+01	4.97E-01	1.38E+01	1.26E+01	4.71E-01	1.31E+01	1.51E-05	5.63E-07	1.56E-05
	N_2O	3.39E-04	1.37E-06	3.41E-04	1.54E-04	6.21E-07	1.55E-04	1.46E-04	5.89E-07	1.46E-04	1.74E-10	7.03E-13	1.75E-10
	CH_4	2.70E-01	2.14E-01	4.83E-01	1.22E-01	9.69E-02	2.19E-01	1.16E-01	9.18E-02	2.08E-01	1.38E-07	1.10E-07	2.48E-07
	CO_2e (20-year)	4.88E+01	1.65E+01	6.53E+01	2.21E+01	7.47E+00	2.96E+01	2.10E+01	7.08E+00	2.81E+01	2.51E-05	8.46E-06	3.35E-05
	CO_2e (100-year)	3.62E+01	6.44E+00	4.26E+01	1.64E+01	2.92E+00	1.93E+01	1.55E+01	2.77E+00	1.83E+01	1.86E-05	3.30E-06	2.19E-05
	CO_2e (500-year)	3.14E+01	2.72E+00	3.41E+01	1.43E+01	1.23E+00	1.55E+01	1.35E+01	1.17E+00	1.47E+01	1.61E-05	1.40E-06	1.75E-05

Table D-2: Upstream Greenhouse Gas Inventory Results for Marginal Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Onshore Gas	CO_2	5.06E+00	1.10E+00	6.16E+00	2.30E+00	4.97E-01	2.79E+00	2.18E+00	4.71E-01	2.65E+00	2.60E-06	5.63E-07	3.16E-06
	N_2O	1.42E-04	1.37E-06	1.44E-04	6.46E-05	6.21E-07	6.52E-05	6.13E-05	5.89E-07	6.18E-05	7.32E-11	7.03E-13	7.39E-11
	CH_4	2.92E-01	2.14E-01	5.05E-01	1.32E-01	9.69E-02	2.29E-01	1.25E-01	9.18E-02	2.17E-01	1.50E-07	1.10E-07	2.59E-07
	CO_2e (20-year)	2.61E+01	1.65E+01	4.26E+01	1.18E+01	7.47E+00	1.93E+01	1.12E+01	7.08E+00	1.83E+01	1.34E-05	8.46E-06	2.19E-05
	CO_2e (100-year)	1.24E+01	6.44E+00	1.88E+01	5.62E+00	2.92E+00	8.54E+00	5.33E+00	2.77E+00	8.10E+00	6.37E-06	3.30E-06	9.67E-06
	CO_2e (500-year)	7.30E+00	2.72E+00	1.00E+01	3.31E+00	1.23E+00	4.55E+00	3.14E+00	1.17E+00	4.31E+00	3.75E-06	1.40E-06	5.15E-06
Marg. Offshore Gas	CO_2	5.34E+00	1.10E+00	6.43E+00	2.42E+00	4.97E-01	2.92E+00	2.30E+00	4.71E-01	2.77E+00	2.74E-06	5.63E-07	3.30E-06
	N_2O	2.53E-04	1.37E-06	2.55E-04	1.15E-04	6.21E-07	1.16E-04	1.09E-04	5.89E-07	1.10E-04	1.30E-10	7.03E-13	1.31E-10
	CH_4	8.46E-02	2.14E-01	2.98E-01	3.84E-02	9.69E-02	1.35E-01	3.64E-02	9.18E-02	1.28E-01	4.34E-08	1.10E-07	1.53E-07
	CO_2e (20-year)	1.15E+01	1.65E+01	2.80E+01	5.22E+00	7.47E+00	1.27E+01	4.95E+00	7.08E+00	1.20E+01	5.91E-06	8.46E-06	1.44E-05
	CO_2e (100-year)	7.53E+00	6.44E+00	1.40E+01	3.42E+00	2.92E+00	6.33E+00	3.24E+00	2.77E+00	6.00E+00	3.87E-06	3.30E-06	7.17E-06
	CO_2e (500-year)	6.02E+00	2.72E+00	8.74E+00	2.73E+00	1.23E+00	3.96E+00	2.59E+00	1.17E+00	3.76E+00	3.09E-06	1.40E-06	4.49E-06
Marg. Assoc. Gas	CO_2	4.91E+00	1.10E+00	6.00E+00	2.23E+00	4.97E-01	2.72E+00	2.11E+00	4.71E-01	2.58E+00	2.52E-06	5.63E-07	3.08E-06
	N_2O	1.37E-04	1.37E-06	1.39E-04	6.23E-05	6.21E-07	6.29E-05	5.90E-05	5.89E-07	5.96E-05	7.05E-11	7.03E-13	7.12E-11
	CH_4	2.45E-01	2.14E-01	4.58E-01	1.11E-01	9.69E-02	2.08E-01	1.05E-01	9.18E-02	1.97E-01	1.26E-07	1.10E-07	2.35E-07
	CO_2e (20-year)	2.26E+01	1.65E+01	3.90E+01	1.02E+01	7.47E+00	1.77E+01	9.70E+00	7.08E+00	1.68E+01	1.16E-05	8.46E-06	2.00E-05
	CO_2e (100-year)	1.11E+01	6.44E+00	1.75E+01	5.02E+00	2.92E+00	7.94E+00	4.76E+00	2.77E+00	7.53E+00	5.68E-06	3.30E-06	8.99E-06
	CO_2e (500-year)	6.79E+00	2.72E+00	9.51E+00	3.08E+00	1.23E+00	4.31E+00	2.92E+00	1.17E+00	4.09E+00	3.49E-06	1.40E-06	4.88E-06

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Tight Gas	CO_2	5.46E+00	1.10E+00	6.55E+00	2.48E+00	4.97E-01	2.97E+00	2.35E+00	4.71E-01	2.82E+00	2.80E-06	5.63E-07	3.36E-06
	N_2O	1.55E-04	1.37E-06	1.57E-04	7.04E-05	6.21E-07	7.10E-05	6.67E-05	5.89E-07	6.73E-05	7.97E-11	7.03E-13	8.04E-11
	CH_4	6.65E-01	2.14E-01	8.79E-01	3.02E-01	9.69E-02	3.99E-01	2.86E-01	9.18E-02	3.78E-01	3.42E-07	1.10E-07	4.51E-07
	SF_6	5.34E+01	1.65E+01	6.99E+01	2.42E+01	7.47E+00	3.17E+01	2.30E+01	7.08E+00	3.00E+01	2.74E-05	8.46E-06	3.59E-05
	CO_2e (20-year)	2.21E+01	6.44E+00	2.86E+01	1.00E+01	2.92E+00	1.30E+01	9.52E+00	2.77E+00	1.23E+01	1.14E-05	3.30E-06	1.47E-05
	CO_2e (100-year)	1.05E+01	2.72E+00	1.33E+01	4.78E+00	1.23E+00	6.01E+00	4.53E+00	1.17E+00	5.70E+00	5.41E-06	1.40E-06	6.81E-06
	CO_2e (500-year)	5.78E+00	1.10E+00	6.87E+00	2.62E+00	4.97E-01	3.12E+00	2.48E+00	4.71E-01	2.95E+00	2.97E-06	5.63E-07	3.53E-06
Marg. Barnett Shale Gas	CO_2	1.72E-04	1.37E-06	1.73E-04	7.79E-05	6.21E-07	7.85E-05	7.39E-05	5.89E-07	7.44E-05	8.82E-11	7.03E-13	8.89E-11
	N_2O	6.58E-01	2.14E-01	8.72E-01	2.99E-01	9.69E-02	3.96E-01	2.83E-01	9.18E-02	3.75E-01	3.38E-07	1.10E-07	4.48E-07
	CH_4	5.32E+01	1.65E+01	6.97E+01	2.41E+01	7.47E+00	3.16E+01	2.29E+01	7.08E+00	3.00E+01	2.73E-05	8.46E-06	3.58E-05
	CO_2e (20-year)	2.23E+01	6.44E+00	2.87E+01	1.01E+01	2.92E+00	1.30E+01	9.58E+00	2.77E+00	1.23E+01	1.14E-05	3.30E-06	1.47E-05
	CO_2e (100-year)	1.08E+01	2.72E+00	1.35E+01	4.90E+00	1.23E+00	6.14E+00	4.65E+00	1.17E+00	5.81E+00	5.55E-06	1.40E-06	6.95E-06
	CO_2e (500-year)	5.85E+00	1.10E+00	6.95E+00	2.65E+00	4.97E-01	3.15E+00	2.52E+00	4.71E-01	2.99E+00	3.00E-06	5.63E-07	3.57E-06
Marg. Marcellus Shale Gas	CO_2	4.52E-04	1.37E-06	4.53E-04	2.05E-04	6.21E-07	2.06E-04	1.94E-04	5.89E-07	1.95E-04	2.32E-10	7.03E-13	2.33E-10
	N_2O	6.35E-01	2.14E-01	8.49E-01	2.88E-01	9.69E-02	3.85E-01	2.73E-01	9.18E-02	3.65E-01	3.26E-07	1.10E-07	4.36E-07
	CH_4	5.17E+01	1.65E+01	6.82E+01	2.35E+01	7.47E+00	3.09E+01	2.22E+01	7.08E+00	2.93E+01	2.66E-05	8.46E-06	3.50E-05
	CO_2e (20-year)	2.19E+01	6.44E+00	2.83E+01	9.92E+00	2.92E+00	1.28E+01	9.40E+00	2.77E+00	1.22E+01	1.12E-05	3.30E-06	1.45E-05
	CO_2e (100-year)	1.07E+01	2.72E+00	1.35E+01	4.87E+00	1.23E+00	6.11E+00	4.62E+00	1.17E+00	5.79E+00	5.52E-06	1.40E-06	6.91E-06
	CO_2e (500-year)	5.45E+00	1.10E+00	6.54E+00	2.47E+00	4.97E-01	2.97E+00	2.34E+00	4.71E-01	2.81E+00	2.80E-06	5.63E-07	3.36E-06
Marg. CBM Gas	CO_2	1.55E-04	1.37E-06	1.56E-04	7.03E-05	6.21E-07	7.09E-05	6.66E-05	5.89E-07	6.72E-05	7.96E-11	7.03E-13	8.03E-11
	N_2O	2.49E-01	2.14E-01	4.62E-01	1.13E-01	9.69E-02	2.10E-01	1.07E-01	9.18E-02	1.99E-01	1.28E-07	1.10E-07	2.37E-07
	CH_4	2.34E+01	1.65E+01	3.99E+01	1.06E+01	7.47E+00	1.81E+01	1.01E+01	7.08E+00	1.71E+01	1.20E-05	8.46E-06	2.05E-05
	CO_2e (20-year)	1.17E+01	6.44E+00	1.81E+01	5.31E+00	2.92E+00	8.23E+00	5.03E+00	2.77E+00	7.80E+00	6.01E-06	3.30E-06	9.32E-06
	CO_2e (100-year)	7.36E+00	2.72E+00	1.01E+01	3.34E+00	1.23E+00	4.57E+00	3.16E+00	1.17E+00	4.33E+00	3.78E-06	1.40E-06	5.18E-06
	CO_2e (500-year)	2.93E+01	1.10E+00	3.04E+01	1.33E+01	4.97E-01	1.38E+01	1.26E+01	4.71E-01	1.31E+01	1.50E-05	5.63E-07	1.56E-05
Marg. LNG Gas	CO_2	3.38E-04	1.37E-06	3.40E-04	1.53E-04	6.21E-07	1.54E-04	1.45E-04	5.89E-07	1.46E-04	1.74E-10	7.03E-13	1.74E-10
	N_2O	2.63E-01	2.14E-01	4.77E-01	1.19E-01	9.69E-02	2.16E-01	1.13E-01	9.18E-02	2.05E-01	1.35E-07	1.10E-07	2.45E-07
	CH_4	4.83E+01	1.65E+01	6.48E+01	2.19E+01	7.47E+00	2.94E+01	2.08E+01	7.08E+00	2.79E+01	2.48E-05	8.46E-06	3.33E-05
	CO_2e (20-year)	3.60E+01	6.44E+00	4.24E+01	1.63E+01	2.92E+00	1.92E+01	1.55E+01	2.77E+00	1.82E+01	1.85E-05	3.30E-06	2.18E-05
	CO_2e (100-year)	3.13E+01	2.72E+00	3.41E+01	1.42E+01	1.23E+00	1.55E+01	1.35E+01	1.17E+00	1.46E+01	1.61E-05	1.40E-06	1.75E-05
	CO_2e (500-year)	5.46E+00	1.10E+00	6.55E+00	2.48E+00	4.97E-01	2.97E+00	2.35E+00	4.71E-01	2.82E+00	2.80E-06	5.63E-07	3.36E-06

Table D-3: Upstream Greenhouse Gas Inventory Results for Coal

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Coal	CO_2	1.32E+00	1.33E+00	2.64E+00	5.97E-01	6.02E-01	1.20E+00	5.66E-01	5.71E-01	1.14E+00
	N_2O	5.29E-04	3.21E-05	5.61E-04	2.40E-04	1.46E-05	2.54E-04	2.27E-04	1.38E-05	2.41E-04
	CH_4	3.78E-01	7.23E-04	3.79E-01	1.72E-01	3.28E-04	1.72E-01	1.63E-01	3.11E-04	1.63E-01
	CO_2e (20-year)	28.7	1.4	30.1	13.0	0.6	13.7	12.3	0.6	12.9
	CO_2e (100-year)	10.9	1.4	12.3	5.0	0.6	5.6	4.7	0.6	5.3
	CO_2e (500-year)	4.3	1.3	5.6	1.9	0.6	2.5	1.8	0.6	2.4
Illinois No. 6 Coal	CO_2	2.53E+00	1.33E+00	3.86E+00	1.15E+00	6.02E-01	1.75E+00	1.09E+00	5.71E-01	1.66E+00
	N_2O	3.97E-05	3.21E-05	7.18E-05	1.80E-05	1.46E-05	3.26E-05	1.71E-05	1.38E-05	3.09E-05
	CH_4	9.40E-01	7.23E-04	9.41E-01	4.27E-01	3.28E-04	4.27E-01	4.04E-01	3.11E-04	4.05E-01
	SF_6	4.98E-07	5.47E-12	4.98E-07	2.26E-07	2.48E-12	2.26E-07	2.14E-07	2.35E-12	2.14E-07
	CO_2e (20-year)	70.3	1.4	71.7	31.9	0.6	32.5	30.2	0.6	30.8
	CO_2e (100-year)	26.1	1.4	27.4	11.8	0.6	12.4	11.2	0.6	11.8
	CO_2e (500-year)	9.7	1.3	11.0	4.4	0.6	5.0	4.2	0.6	4.7
PRB Coal	CO_2	7.73E-01	1.33E+00	2.10E+00	3.51E-01	6.02E-01	9.53E-01	3.32E-01	5.71E-01	9.03E-01
	N_2O	7.48E-04	3.21E-05	7.80E-04	3.39E-04	1.46E-05	3.54E-04	3.22E-04	1.38E-05	3.35E-04
	CH_4	1.26E-01	7.23E-04	1.26E-01	5.70E-02	3.28E-04	5.74E-02	5.41E-02	3.11E-04	5.44E-02
	CO_2e (20-year)	10.0	1.4	11.4	4.6	0.6	5.2	4.3	0.6	4.9
	CO_2e (100-year)	4.1	1.4	5.5	1.9	0.6	2.5	1.8	0.6	2.4
	CO_2e (500-year)	1.8	1.3	3.2	0.8	0.6	1.4	0.8	0.6	1.4

Table D-4: Upstream Greenhouse Gas Inventory Results for Natural Gas-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Gas)	CO_2	5.66E+01	1.07E+01	8.75E+02	0.00E+00	9.42E+02	2.57E+01	4.86E+00	3.97E+02	0.00E+00	4.27E+02	7.13E+00	1.35E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	1.83E-03	1.34E-05	2.45E-03	0.00E+00	4.29E-03	8.29E-04	6.07E-06	1.11E-03	0.00E+00	1.94E-03	2.30E-04	1.69E-06	3.08E-04	0.00E+00	5.40E-04
	CH_4	5.18E+00	2.09E+00	2.44E-02	0.00E+00	7.29E+00	2.35E+00	9.47E-01	1.11E-02	0.00E+00	3.31E+00	6.53E-01	2.63E-01	3.07E-03	0.00E+00	9.19E-01
	SF_6	6.32E-07	2.44E-08	0.00E+00	3.16E-04	3.17E-04	2.87E-07	1.11E-08	0.00E+00	1.43E-04	1.44E-04	7.96E-08	3.07E-09	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-yr)	4.30E+02	1.61E+02	8.77E+02	5.15E+00	1.47E+03	1.95E+02	7.30E+01	3.98E+02	2.34E+00	6.68E+02	5.42E+01	2.03E+01	1.11E+02	6.49E-01	1.86E+02
	CO_2e (100-yr)	1.87E+02	6.29E+01	8.76E+02	7.20E+00	1.13E+03	8.47E+01	2.85E+01	3.97E+02	3.27E+00	5.14E+02	2.35E+01	7.92E+00	1.10E+02	9.08E-01	1.43E+02
	CO_2e (500-yr)	9.63E+01	2.66E+01	8.75E+02	1.03E+01	1.01E+03	4.37E+01	1.21E+01	3.97E+02	4.67E+00	4.57E+02	1.21E+01	3.35E+00	1.10E+02	1.30E+00	1.27E+02
Fleet Baseload (Conv. Gas)	CO_2	5.97E+01	1.07E+01	8.75E+02	0.00E+00	9.45E+02	2.71E+01	4.86E+00	3.97E+02	0.00E+00	4.29E+02	7.52E+00	1.35E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	2.03E-03	1.34E-05	2.45E-03	0.00E+00	4.49E-03	9.20E-04	6.07E-06	1.11E-03	0.00E+00	2.04E-03	2.56E-04	1.69E-06	3.08E-04	0.00E+00	5.65E-04
	CH_4	4.25E+00	2.09E+00	2.44E-02	0.00E+00	6.37E+00	1.93E+00	9.47E-01	1.11E-02	0.00E+00	2.89E+00	5.36E-01	2.63E-01	3.07E-03	0.00E+00	8.02E-01
	SF_6	5.11E-08	2.44E-08	0.00E+00	3.16E-04	3.16E-04	2.32E-08	1.11E-08	0.00E+00	1.43E-04	1.43E-04	6.44E-09	3.07E-09	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-yr)	3.67E+02	1.61E+02	8.77E+02	5.15E+00	1.41E+03	1.66E+02	7.30E+01	3.98E+02	2.34E+00	6.39E+02	4.62E+01	2.03E+01	1.11E+02	6.49E-01	1.78E+02
	CO_2e (100-yr)	1.67E+02	6.29E+01	8.76E+02	7.20E+00	1.11E+03	7.56E+01	2.85E+01	3.97E+02	3.27E+00	5.05E+02	2.10E+01	7.92E+00	1.10E+02	9.08E-01	1.40E+02
	CO_2e (500-yr)	9.23E+01	2.66E+01	8.75E+02	1.03E+01	1.00E+03	4.19E+01	1.21E+01	3.97E+02	4.67E+00	4.56E+02	1.16E+01	3.35E+00	1.10E+02	1.30E+00	1.27E+02
Fleet Baseload (Unconv. Gas)	CO_2	5.45E+01	1.07E+01	8.75E+02	0.00E+00	9.40E+02	2.47E+01	4.86E+00	3.97E+02	0.00E+00	4.26E+02	6.87E+00	1.35E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.69E-03	1.34E-05	2.45E-03	0.00E+00	4.15E-03	7.67E-04	6.07E-06	1.11E-03	0.00E+00	1.88E-03	2.13E-04	1.69E-06	3.08E-04	0.00E+00	5.23E-04
	CH_4	5.81E+00	2.09E+00	2.44E-02	0.00E+00	7.92E+00	2.63E+00	9.47E-01	1.11E-02	0.00E+00	3.59E+00	7.32E-01	2.63E-01	3.07E-03	0.00E+00	9.98E-01
	SF_6	1.02E-06	2.44E-08	0.00E+00	3.16E-04	3.17E-04	4.65E-07	1.11E-08	0.00E+00	1.43E-04	1.44E-04	1.29E-07	3.07E-09	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-yr)	4.73E+02	1.61E+02	8.77E+02	5.15E+00	1.52E+03	2.15E+02	7.30E+01	3.98E+02	2.34E+00	6.88E+02	5.96E+01	2.03E+01	1.11E+02	6.49E-01	1.91E+02
	CO_2e (100-yr)	2.00E+02	6.29E+01	8.76E+02	7.20E+00	1.15E+03	9.08E+01	2.85E+01	3.97E+02	3.27E+00	5.20E+02	2.52E+01	7.92E+00	1.10E+02	9.08E-01	1.44E+02
	CO_2e (500-yr)	9.90E+01	2.66E+01	8.75E+02	1.03E+01	1.01E+03	4.49E+01	1.21E+01	3.97E+02	4.67E+00	4.59E+02	1.25E+01	3.35E+00	1.10E+02	1.30E+00	1.27E+02
Fleet Baseload (Marg. Onshore Gas)	CO_2	4.95E+01	1.07E+01	8.75E+02	0.00E+00	9.35E+02	2.24E+01	4.86E+00	3.97E+02	0.00E+00	4.24E+02	6.24E+00	1.35E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.39E-03	1.34E-05	2.45E-03	0.00E+00	3.85E-03	6.32E-04	6.07E-06	1.11E-03	0.00E+00	1.75E-03	1.75E-04	1.69E-06	3.08E-04	0.00E+00	4.85E-04
	CH_4	2.85E+00	2.09E+00	2.44E-02	0.00E+00	4.96E+00	1.29E+00	9.47E-01	1.11E-02	0.00E+00	2.25E+00	3.59E-01	2.63E-01	3.07E-03	0.00E+00	6.25E-01
	SF_6	9.27E-09	2.44E-08	0.00E+00	3.16E-04	3.16E-04	4.21E-09	1.11E-08	0.00E+00	1.43E-04	1.43E-04	1.17E-09	3.07E-09	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-yr)	2.55E+02	1.61E+02	8.77E+02	5.15E+00	1.30E+03	1.16E+02	7.30E+01	3.98E+02	2.34E+00	5.89E+02	3.21E+01	2.03E+01	1.11E+02	6.49E-01	1.64E+02
	CO_2e (100-yr)	1.21E+02	6.29E+01	8.76E+02	7.20E+00	1.07E+03	5.50E+01	2.85E+01	3.97E+02	3.27E+00	4.84E+02	1.53E+01	7.92E+00	1.10E+02	9.08E-01	1.34E+02
	CO_2e (500-yr)	7.14E+01	2.66E+01	8.75E+02	1.03E+01	9.83E+02	3.24E+01	1.21E+01	3.97E+02	4.67E+00	4.46E+02	8.99E+00	3.35E+00	1.10E+02	1.30E+00	1.24E+02
GTSC (Avg. Gas)	CO_2	7.08E+01	1.34E+01	1.33E+03	0.00E+00	1.41E+03	3.21E+01	6.08E+00	6.04E+02	0.00E+00	6.42E+02	8.92E+00	1.69E+00	1.68E+02	0.00E+00	1.78E+02
	N_2O	2.29E-03	1.67E-05	2.86E-05	0.00E+00	2.33E-03	1.04E-03	7.59E-06	1.30E-05	0.00E+00	1.06E-03	2.88E-04	2.11E-06	3.61E-06	0.00E+00	2.94E-04
	CH_4	6.48E+00	2.61E+00	2.64E-03	0.00E+00	9.10E+00	2.94E+00	1.18E+00	1.20E-03	0.00E+00	4.13E+00	8.17E-01	3.29E-01	3.32E-04	0.00E+00	1.15E+00
	SF_6	7.91E-07	3.05E-08	4.34E-08	3.16E-04	3.17E-04	3.59E-07	1.38E-08	1.97E-08	1.43E-04	1.44E-04	9.96E-08	3.85E-09	5.47E-09	3.98E-05	3.99E-05
	CO_2e (20-yr)	5.38E+02	2.01E+02	1.33E+03	5.15E+00	2.08E+03	2.44E+02	9.13E+01	6.04E+02	2.34E+00	9.41E+02	6.78E+01	2.54E+01	1.68E+02	6.49E-01	2.62E+02
	CO_2e (100-yr)	2.34E+02	7.87E+01	1.33E+03	7.20E+00	1.65E+03	1.06E+02	3.57E+01	6.04E+02	3.27E+00	7.48E+02	2.94E+01	9.91E+00	1.68E+02	9.08E-01	2.08E+02
	CO_2e (500-yr)	1.20E+02	3.32E+01	1.33E+03	1.03E+01	1.49E+03	5.46E+01	1.51E+01	6.04E+02	4.67E+00	6.78E+02	1.52E+01	4.19E+00	1.68E+02	1.30E+00	1.88E+02

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
NGCC (Avg. Gas)	CO_2	4.60E+01	8.70E+00	8.66E+02	0.00E+00	9.21E+02	2.08E+01	3.95E+00	3.93E+02	0.00E+00	4.18E+02	5.79E+00	1.10E+00	1.09E+02	0.00E+00	1.16E+02
	N_2O	1.48E-03	1.09E-05	3.33E-05	0.00E+00	1.53E-03	6.73E-04	4.93E-06	1.51E-05	0.00E+00	6.93E-04	1.87E-04	1.37E-06	4.20E-06	0.00E+00	1.93E-04
	CH_4	4.21E+00	1.69E+00	1.31E-03	0.00E+00	5.90E+00	1.91E+00	7.69E-01	5.94E-04	0.00E+00	2.68E+00	5.30E-01	2.13E-01	1.65E-04	0.00E+00	7.44E-01
	SF_6	5.13E-07	1.98E-08	7.55E-07	3.16E-04	3.17E-04	2.33E-07	8.99E-09	3.42E-07	1.43E-04	1.44E-04	6.47E-08	2.50E-09	9.51E-08	3.98E-05	4.00E-05
	CO_2e (20-yr)	3.49E+02	1.31E+02	8.67E+02	5.15E+00	1.35E+03	1.58E+02	5.93E+01	3.93E+02	2.34E+00	6.13E+02	4.40E+01	1.65E+01	1.09E+02	6.49E-01	1.70E+02
	CO_2e (100-yr)	1.52E+02	5.11E+01	8.66E+02	7.20E+00	1.08E+03	6.88E+01	2.32E+01	3.93E+02	3.27E+00	4.88E+02	1.91E+01	6.43E+00	1.09E+02	9.08E-01	1.36E+02
	CO_2e (500-yr)	7.82E+01	2.16E+01	8.66E+02	1.03E+01	9.77E+02	3.55E+01	9.79E+00	3.93E+02	4.67E+00	4.43E+02	9.85E+00	2.72E+00	1.09E+02	1.30E+00	1.23E+02
NGCC/ccs (Avg.Gas)	CO_2	5.39E+01	1.02E+01	1.13E+02	0.00E+00	1.77E+02	2.44E+01	4.62E+00	5.13E+01	0.00E+00	8.03E+01	6.79E+00	1.28E+00	1.42E+01	0.00E+00	2.23E+01
	N_2O	1.74E-03	1.27E-05	5.18E-05	0.00E+00	1.80E-03	7.89E-04	5.78E-06	2.35E-05	0.00E+00	8.18E-04	2.19E-04	1.60E-06	6.53E-06	0.00E+00	2.27E-04
	CH_4	4.93E+00	1.99E+00	1.71E-03	0.00E+00	6.92E+00	2.24E+00	9.01E-01	7.78E-04	0.00E+00	3.14E+00	6.21E-01	2.50E-01	2.16E-04	0.00E+00	8.72E-01
	SF_6	6.02E-07	2.32E-08	8.81E-07	3.16E-04	3.17E-04	2.73E-07	1.05E-08	4.00E-07	1.43E-04	1.44E-04	7.58E-08	2.93E-09	1.11E-07	3.98E-05	4.00E-05
	CO_2e (20-yr)	4.09E+02	1.53E+02	1.13E+02	5.15E+00	6.81E+02	1.86E+02	6.95E+01	5.13E+01	2.34E+00	3.09E+02	5.16E+01	1.93E+01	1.43E+01	6.49E-01	8.58E+01
	CO_2e (100-yr)	1.78E+02	5.99E+01	1.13E+02	7.20E+00	3.58E+02	8.06E+01	2.71E+01	5.13E+01	3.27E+00	1.62E+02	2.24E+01	7.54E+00	1.43E+01	9.08E-01	4.51E+01
	CO_2e (500-yr)	9.16E+01	2.53E+01	1.13E+02	1.03E+01	2.40E+02	4.16E+01	1.15E+01	5.13E+01	4.67E+00	1.09E+02	1.15E+01	3.19E+00	1.42E+01	1.30E+00	3.03E+01

Table D-5: Upstream Greenhouse Gas Inventory Results for Coal-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Coal)	CO_2	1.38E+01	1.39E+01	2.33E+03	0.00E+00	2.35E+03	6.26E+00	6.31E+00	1.06E+03	0.00E+00	1.07E+03	1.74E+00	1.75E+00	2.93E+02	0.00E+00	2.97E+02
	N_2O	5.54E-03	3.36E-04	3.99E-02	0.00E+00	4.58E-02	2.51E-03	1.53E-04	1.81E-02	0.00E+00	2.08E-02	6.98E-04	4.24E-05	5.03E-03	0.00E+00	5.77E-03
	CH_4	3.96E+00	7.57E-03	2.67E-02	0.00E+00	4.00E+00	1.80E+00	3.43E-03	1.21E-02	0.00E+00	1.81E+00	4.99E-01	9.54E-04	3.37E-03	0.00E+00	5.04E-01
	SF_6	1.77E-06	5.73E-11	0.00E+00	3.16E-04	3.18E-04	8.03E-07	2.60E-11	0.00E+00	1.43E-04	1.44E-04	2.23E-07	7.22E-12	0.00E+00	3.98E-05	4.00E-05
	CO_2e (20-year)	300.8	14.5	2,340.1	5.2	2,660.6	136.4	6.6	1,061.5	2.3	1,206.8	37.9	1.8	294.9	0.6	335.2
	CO_2e (100-year)	114.6	14.2	2,339.2	7.2	2,475.2	52.0	6.4	1,061.1	3.3	1,122.7	14.4	1.8	294.7	0.9	311.9
	CO_2e (500-year)	44.8	14.0	2,333.0	10.3	2,402.1	20.3	6.4	1,058.2	4.7	1,089.6	5.6	1.8	294.0	1.3	302.7
EXPC (Illinois No. 6 Coal)	CO_2	2.24E+01	1.18E+01	2.23E+03	0.00E+00	2.27E+03	1.02E+01	5.34E+00	1.01E+03	0.00E+00	1.03E+03	2.83E+00	1.48E+00	2.81E+02	0.00E+00	2.85E+02
	N_2O	3.52E-04	2.85E-04	3.77E-02	0.00E+00	3.83E-02	1.60E-04	1.29E-04	1.71E-02	0.00E+00	1.74E-02	4.44E-05	3.59E-05	4.75E-03	0.00E+00	4.83E-03
	CH_4	8.35E+00	6.42E-03	2.51E-02	0.00E+00	8.38E+00	3.79E+00	2.91E-03	1.14E-02	0.00E+00	3.80E+00	1.05E+00	8.08E-04	3.17E-03	0.00E+00	1.06E+00
	SF_6	4.42E-06	4.85E-11	6.11E-07	3.16E-04	3.21E-04	2.00E-06	2.20E-11	2.77E-07	1.43E-04	1.46E-04	5.57E-07	6.11E-12	7.70E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	623.7	12.3	2,243.5	5.2	2,884.7	282.9	5.6	1,017.6	2.3	1,308.5	78.6	1.6	282.7	0.6	363.5
	CO_2e (100-year)	231.4	12.0	2,242.7	7.2	2,493.3	104.9	5.5	1,017.3	3.3	1,130.9	29.2	1.5	282.6	0.9	314.1
	CO_2e (500-year)	86.1	11.9	2,236.8	10.3	2,345.0	39.0	5.4	1,014.6	4.7	1,063.7	10.8	1.5	281.8	1.3	295.5
IGCC (Illinois No. 6 Coal)	CO_2	1.98E+01	1.04E+01	1.89E+03	0.00E+00	1.92E+03	8.98E+00	4.72E+00	8.57E+02	0.00E+00	8.71E+02	2.49E+00	1.31E+00	2.38E+02	0.00E+00	2.42E+02
	N_2O	3.11E-04	2.52E-04	4.67E-05	0.00E+00	6.09E-04	1.41E-04	1.14E-04	2.12E-05	0.00E+00	2.76E-04	3.92E-05	3.17E-05	5.89E-06	0.00E+00	7.68E-05
	CH_4	7.37E+00	5.66E-03	9.58E-03	0.00E+00	7.38E+00	3.34E+00	2.57E-03	4.35E-03	0.00E+00	3.35E+00	9.28E-01	7.13E-04	1.21E-03	0.00E+00	9.30E-01
	SF_6	3.90E-06	4.28E-11	7.69E-07	3.16E-04	3.21E-04	1.77E-06	1.94E-11	3.49E-07	1.43E-04	1.45E-04	4.91E-07	5.40E-12	9.69E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	550.4	10.9	1,890.8	5.2	2,457.2	249.7	4.9	857.7	2.3	1,114.6	69.3	1.4	238.2	0.6	309.6
	CO_2e (100-year)	204.2	10.6	1,890.4	7.2	2,112.4	92.6	4.8	857.5	3.3	958.2	25.7	1.3	238.2	0.9	266.2
	CO_2e (500-year)	76.0	10.5	1,890.2	10.3	1,987.0	34.5	4.8	857.4	4.7	901.3	9.6	1.3	238.2	1.3	250.4
IGCC/CCS (Illinois No. 6 Coal)	CO_2	2.33E+01	1.22E+01	2.46E+02	0.00E+00	2.81E+02	1.06E+01	5.55E+00	1.11E+02	0.00E+00	1.28E+02	2.94E+00	1.54E+00	3.10E+01	0.00E+00	3.54E+01
	N_2O	3.66E-04	2.96E-04	9.13E-05	0.00E+00	7.54E-04	1.66E-04	1.34E-04	4.14E-05	0.00E+00	3.42E-04	4.61E-05	3.73E-05	1.15E-05	0.00E+00	9.50E-05
	CH_4	8.67E+00	6.67E-03	1.15E-02	0.00E+00	8.69E+00	3.93E+00	3.02E-03	5.20E-03	0.00E+00	3.94E+00	1.09E+00	8.40E-04	1.45E-03	0.00E+00	1.10E+00
	SF_6	4.59E-06	5.04E-11	8.72E-07	3.16E-04	3.21E-04	2.08E-06	2.29E-11	3.96E-07	1.43E-04	1.46E-04	5.78E-07	6.35E-12	1.10E-07	3.98E-05	4.05E-05
	CO_2e (20-year)	648.1	12.8	246.6	5.2	912.7	294.0	5.8	111.9	2.3	414.0	81.7	1.6	31.1	0.6	115.0
	CO_2e (100-year)	240.4	12.5	246.1	7.2	506.2	109.0	5.7	111.6	3.3	229.6	30.3	1.6	31.0	0.9	63.8
	CO_2e (500-year)	89.5	12.3	245.9	10.3	358.0	40.6	5.6	111.5	4.7	162.4	11.3	1.6	31.0	1.3	45.1

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
SCPC (Illinois No. 6 Coal)	CO_2	1.94E+01	1.02E+01	1.91E+03	0.00E+00	1.94E+03	8.78E+00	4.61E+00	8.66E+02	0.00E+00	8.79E+02	2.44E+00	1.28E+00	2.41E+02	0.00E+00	2.44E+02
	N_2O	3.04E-04	2.46E-04	6.99E-05	0.00E+00	6.20E-04	1.38E-04	1.12E-04	3.17E-05	0.00E+00	2.81E-04	3.83E-05	3.10E-05	8.81E-06	0.00E+00	7.81E-05
	CH_4	7.20E+00	5.53E-03	8.98E-03	0.00E+00	7.22E+00	3.27E+00	2.51E-03	4.07E-03	0.00E+00	3.27E+00	9.07E-01	6.97E-04	1.13E-03	0.00E+00	9.09E-01
	SF_6	3.81E-06	4.19E-11	8.26E-07	3.16E-04	3.21E-04	1.73E-06	1.90E-11	3.74E-07	1.43E-04	1.45E-04	4.80E-07	5.27E-12	1.04E-07	3.98E-05	4.04E-05
	CO_2e (20-year)	538.0	10.6	1,910.1	5.2	2,463.9	244.0	4.8	866.4	2.3	1,117.6	67.8	1.3	240.7	0.6	310.5
	CO_2e (100-year)	199.6	10.4	1,909.7	7.2	2,126.9	90.5	4.7	866.2	3.3	964.7	25.1	1.3	240.6	0.9	268.0
	CO_2e (500-year)	74.3	10.2	1,909.5	10.3	2,004.3	33.7	4.6	866.2	4.7	909.2	9.4	1.3	240.6	1.3	252.5
SCPC/CCS (Illinois No. 6 Coal)	CO_2	2.78E+01	1.46E+01	3.02E+02	0.00E+00	3.45E+02	1.26E+01	6.63E+00	1.37E+02	0.00E+00	1.56E+02	3.51E+00	1.84E+00	3.81E+01	0.00E+00	4.34E+01
	N_2O	4.37E-04	3.53E-04	1.07E-04	0.00E+00	8.97E-04	1.98E-04	1.60E-04	4.85E-05	0.00E+00	4.07E-04	5.50E-05	4.45E-05	1.35E-05	0.00E+00	1.13E-04
	CH_4	1.04E+01	7.95E-03	9.79E-03	0.00E+00	1.04E+01	4.69E+00	3.61E-03	4.44E-03	0.00E+00	4.70E+00	1.30E+00	1.00E-03	1.23E-03	0.00E+00	1.31E+00
	SF_6	5.48E-06	6.02E-11	8.34E-07	3.16E-04	3.22E-04	2.48E-06	2.73E-11	3.78E-07	1.43E-04	1.46E-04	6.90E-07	7.58E-12	1.05E-07	3.98E-05	4.06E-05
	CO_2e (20-year)	773.3	15.3	302.8	5.2	1,096.5	350.7	6.9	137.4	2.3	497.4	97.4	1.9	38.2	0.6	138.2
	CO_2e (100-year)	286.8	14.9	302.4	7.2	611.3	130.1	6.8	137.2	3.3	277.3	36.1	1.9	38.1	0.9	77.0
	CO_2e (500-year)	106.7	14.7	302.2	10.3	434.0	48.4	6.7	137.1	4.7	196.8	13.4	1.9	38.1	1.3	54.7

Table D-6: Comprehensive LCA Metrics for NGCC Power Using the 2010 Domestic NG Mix

Category (Units)	Material or Energy Flow	NGCC with 2010 Domestic Average NG					NGCC with CCS and 2010 Domestic Average NG				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
GHG (kg/MWh)	CO_2	2.08E+01	3.95E+00	3.93E+02	0.00E+00	4.18E+02	2.44E+01	4.62E+00	5.13E+01	0.00E+00	8.03E+01
	N_2O	6.73E-04	4.93E-06	1.51E-05	0.00E+00	6.93E-04	7.89E-04	5.78E-06	2.35E-05	0.00E+00	8.18E-04
	CH_4	1.91E+00	7.69E-01	5.94E-04	0.00E+00	2.68E+00	2.24E+00	9.01E-01	7.78E-04	0.00E+00	3.14E+00
	SF_6	2.33E-07	8.99E-09	3.42E-07	1.43E-04	1.44E-04	2.73E-07	1.05E-08	4.00E-07	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	6.88E+01	2.32E+01	3.93E+02	3.27E+00	4.88E+02	8.06E+01	2.71E+01	5.13E+01	3.27E+00	1.62E+02
Other Air (kg/MWh)	Pb	1.94E-06	1.65E-07	2.71E-06	0.00E+00	4.82E-06	2.27E-06	1.94E-07	3.09E-06	0.00E+00	5.56E-06
	Hg	7.18E-08	5.17E-09	2.46E-08	0.00E+00	1.02E-07	8.42E-08	6.06E-09	3.50E-08	0.00E+00	1.25E-07
	NH_3	1.10E-06	1.99E-06	1.88E-02	0.00E+00	1.88E-02	1.29E-06	2.33E-06	2.03E-02	0.00E+00	2.03E-02
	CO	4.35E-02	6.23E-04	3.12E-03	0.00E+00	4.72E-02	5.10E-02	7.31E-04	4.50E-03	0.00E+00	5.62E-02
	NO_X	4.82E-01	7.79E-04	3.05E-02	0.00E+00	5.13E-01	5.65E-01	9.13E-04	3.42E-02	0.00E+00	6.00E-01
	SO_2	5.87E-03	3.15E-04	1.19E-03	0.00E+00	7.37E-03	6.88E-03	3.69E-04	1.66E-03	0.00E+00	8.91E-03
	VOC	3.81E-01	1.59E-05	3.72E-05	0.00E+00	3.81E-01	4.47E-01	1.86E-05	4.74E-05	0.00E+00	4.47E-01
	PM	1.02E-03	6.50E-05	3.74E-04	0.00E+00	1.46E-03	1.19E-03	7.61E-05	5.53E-04	0.00E+00	1.82E-03
Solid Waste (kg/MWh)	Heavy metals to industrial soil	7.33E-03	2.83E-04	5.26E-04	0.00E+00	8.13E-03	8.59E-03	3.31E-04	5.62E-04	0.00E+00	9.48E-03
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	1.81E+02	2.12E+00	1.04E+03	0.00E+00	1.22E+03	2.12E+02	2.48E+00	2.06E+03	0.00E+00	2.28E+03
	Discharge	2.11E+02	1.39E+00	2.36E+02	0.00E+00	4.48E+02	2.48E+02	1.63E+00	5.22E+02	0.00E+00	7.71E+02
	Consumption	-3.08E+01	7.30E-01	8.03E+02	0.00E+00	7.73E+02	-3.61E+01	8.56E-01	1.54E+03	0.00E+00	1.51E+03
Water Quality (kg/MWh)	Aluminum	4.45E-05	2.55E-06	2.15E-06	0.00E+00	4.92E-05	5.22E-05	2.99E-06	6.88E-06	0.00E+00	6.20E-05
	Arsenic (+V)	2.95E-06	1.37E-07	1.84E-07	0.00E+00	3.27E-06	3.45E-06	1.61E-07	3.25E-07	0.00E+00	3.94E-06
	Copper (+II)	3.84E-06	1.82E-07	2.36E-07	0.00E+00	4.25E-06	4.50E-06	2.14E-07	4.39E-07	0.00E+00	5.15E-06
	Iron	2.46E-04	9.80E-06	2.65E-05	0.00E+00	2.82E-04	2.88E-04	1.15E-05	4.54E-05	0.00E+00	3.45E-04
	Lead (+II)	4.50E-06	2.63E-07	2.92E-07	0.00E+00	5.05E-06	5.27E-06	3.09E-07	7.88E-07	0.00E+00	6.37E-06
	Manganese (+II)	2.68E-03	9.79E-08	2.16E-07	0.00E+00	2.68E-03	3.14E-03	1.15E-07	2.46E-07	0.00E+00	3.14E-03
	Nickel (+II)	1.11E-04	4.94E-06	7.22E-06	0.00E+00	1.24E-04	1.31E-04	5.79E-06	1.12E-05	0.00E+00	1.48E-04
	Strontium	1.52E-07	7.54E-09	5.66E-08	0.00E+00	2.16E-07	1.78E-07	8.84E-09	7.28E-08	0.00E+00	2.60E-07
	Zinc (+II)	7.95E-05	4.16E-06	4.37E-06	0.00E+00	8.80E-05	9.31E-05	4.88E-06	1.07E-05	0.00E+00	1.09E-04
	Ammonium/ammonia	1.81E-04	6.98E-06	1.32E-05	0.00E+00	2.01E-04	2.12E-04	8.18E-06	1.41E-05	0.00E+00	2.34E-04
	Hydrogen chloride	1.72E-11	7.34E-13	4.54E-12	0.00E+00	2.25E-11	2.02E-11	8.61E-13	5.48E-12	0.00E+00	2.65E-11
	Nitrogen (as total N)	8.74E-04	2.76E-08	5.14E-08	0.00E+00	8.74E-04	1.02E-03	3.24E-08	5.48E-08	0.00E+00	1.02E-03
	Phosphate	7.38E-09	2.97E-10	1.17E-08	0.00E+00	1.94E-08	8.65E-09	3.49E-10	1.33E-08	0.00E+00	2.23E-08
	Phosphorus	5.45E-05	2.45E-06	2.60E-06	0.00E+00	5.96E-05	6.39E-05	2.87E-06	7.10E-06	0.00E+00	7.39E-05
Resource Energy (MJ/MWh)	Crude oil	2.70E+00	1.78E-01	6.90E-01	0.00E+00	3.56E+00	3.16E+00	2.08E-01	1.08E+00	0.00E+00	4.45E+00
	Hard coal	1.33E+01	7.21E-01	2.59E+00	0.00E+00	1.66E+01	1.56E+01	8.46E-01	3.58E+00	0.00E+00	2.00E+01
	Lignite	5.22E-03	2.56E-04	6.36E-02	0.00E+00	6.91E-02	6.12E-03	3.00E-04	7.35E-02	0.00E+00	7.99E-02
	Natural gas	9.44E+03	4.55E-01	1.11E+00	0.00E+00	9.44E+03	1.11E+04	5.34E-01	1.56E+00	0.00E+00	1.11E+04
	Uranium	3.10E-02	1.50E-03	2.06E-01	0.00E+00	2.38E-01	3.64E-02	1.76E-03	2.35E-01	0.00E+00	2.73E-01
	Total resource energy	9.45E+03	1.36E+00	4.66E+00	0.00E+00	9.46E+03	1.11E+04	1.59E+00	6.52E+00	0.00E+00	1.11E+04
Energy Return on Investment		N/A	N/A	N/A	N/A	61.4%	N/A	N/A	N/A	N/A	0.481

Table D-7: Comprehensive LCA Metrics for GTSC and Fleet Average Natural Gas Power Using the 2010 Domestic NG Mix

Category (Units)	Material or Energy Flow	GTSC with 2010 Domestic Average NG					Fleet Baseload NG Power with 2010 Domestic Average NG				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
GHG (kg/MWh)	CO_2	3.21E+01	6.08E+00	6.04E+02	0.00E+00	6.42E+02	2.57E+01	4.86E+00	3.97E+02	0.00E+00	4.27E+02
	N_2O	1.04E-03	7.59E-06	1.30E-05	0.00E+00	1.06E-03	8.29E-04	6.07E-06	1.11E-03	0.00E+00	1.94E-03
	CH_4	2.94E+00	1.18E+00	1.20E-03	0.00E+00	4.13E+00	2.35E+00	9.47E-01	1.11E-02	0.00E+00	3.31E+00
	SF_6	3.59E-07	1.38E-08	1.97E-08	1.43E-04	1.44E-04	2.87E-07	1.11E-08	0.00E+00	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.06E+02	3.57E+01	6.04E+02	3.27E+00	7.48E+02	8.47E+01	2.85E+01	3.97E+02	3.27E+00	5.14E+02
Other Air (kg/MWh)	Pb	2.99E-06	2.55E-07	6.27E-07	0.00E+00	3.87E-06	2.39E-06	2.04E-07	0.00E+00	0.00E+00	2.59E-06
	Hg	1.11E-07	7.96E-09	7.08E-09	0.00E+00	1.26E-07	8.85E-08	6.37E-09	0.00E+00	0.00E+00	9.48E-08
	NH_3	1.70E-06	3.07E-06	2.90E-02	0.00E+00	2.90E-02	1.36E-06	2.45E-06	0.00E+00	0.00E+00	3.81E-06
	CO	6.70E-02	9.61E-04	5.48E-03	0.00E+00	7.34E-02	5.36E-02	7.68E-04	3.35E-04	0.00E+00	5.47E-02
	NO_X	7.42E-01	1.20E-03	4.87E-02	0.00E+00	7.92E-01	5.93E-01	9.59E-04	2.95E-01	0.00E+00	8.89E-01
	SO_2	9.05E-03	4.85E-04	1.53E-03	0.00E+00	1.11E-02	7.23E-03	3.88E-04	4.14E-03	0.00E+00	1.18E-02
	VOC	5.87E-01	2.45E-05	1.64E-04	0.00E+00	5.87E-01	4.69E-01	1.96E-05	0.00E+00	0.00E+00	4.69E-01
	PM	1.57E-03	1.00E-04	5.77E-04	0.00E+00	2.25E-03	1.25E-03	8.00E-05	0.00E+00	0.00E+00	1.33E-03
Solid Waste (kg/MWh)	Heavy metals to industrial soil	1.13E-02	4.36E-04	6.22E-04	0.00E+00	1.23E-02	9.02E-03	3.48E-04	0.00E+00	0.00E+00	9.37E-03
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	2.78E+02	3.26E+00	5.07E+00	0.00E+00	2.87E+02	2.22E+02	2.61E+00	1.12E+03	0.00E+00	1.34E+03
	Discharge	3.26E+02	2.14E+00	4.03E+00	0.00E+00	3.32E+02	2.60E+02	1.71E+00	2.52E+02	0.00E+00	5.14E+02
	Consumption	-4.75E+01	1.12E+00	1.03E+00	0.00E+00	-4.53E+01	-3.79E+01	8.99E-01	8.63E+02	0.00E+00	8.26E+02
Water Quality (kg/MWh)	Aluminum	6.86E-05	3.92E-06	6.64E-08	0.00E+00	7.26E-05	5.48E-05	3.14E-06	0.00E+00	0.00E+00	5.80E-05
	Arsenic (+V)	4.54E-06	2.12E-07	1.68E-07	0.00E+00	4.92E-06	3.63E-06	1.69E-07	0.00E+00	0.00E+00	3.80E-06
	Copper (+II)	5.91E-06	2.81E-07	6.02E-07	0.00E+00	6.79E-06	4.72E-06	2.24E-07	0.00E+00	0.00E+00	4.95E-06
	Iron	3.79E-04	1.51E-05	4.07E-05	0.00E+00	4.35E-04	3.03E-04	1.21E-05	0.00E+00	0.00E+00	3.15E-04
	Lead (+II)	6.93E-06	4.06E-07	1.45E-07	0.00E+00	7.48E-06	5.54E-06	3.24E-07	0.00E+00	0.00E+00	5.86E-06
	Manganese (+II)	4.13E-03	1.51E-07	3.73E-07	0.00E+00	4.13E-03	3.30E-03	1.21E-07	0.00E+00	0.00E+00	3.30E-03
	Nickel (+II)	1.72E-04	7.60E-06	6.74E-06	0.00E+00	1.86E-04	1.37E-04	6.08E-06	0.00E+00	0.00E+00	1.43E-04
	Strontium	2.34E-07	1.16E-08	2.41E-06	0.00E+00	2.65E-06	1.87E-07	9.29E-09	0.00E+00	0.00E+00	1.97E-07
	Zinc (+II)	1.22E-04	6.42E-06	2.00E-06	0.00E+00	1.31E-04	9.79E-05	5.13E-06	0.00E+00	0.00E+00	1.03E-04
	Ammonium/ammonia	2.79E-04	1.08E-05	1.63E-05	0.00E+00	3.06E-04	2.23E-04	8.60E-06	0.00E+00	0.00E+00	2.31E-04
	Hydrogen chloride	2.65E-11	1.13E-12	7.55E-11	0.00E+00	1.03E-10	2.12E-11	9.04E-13	0.00E+00	0.00E+00	2.21E-11
	Nitrogen (as total N)	1.35E-03	4.26E-08	6.07E-08	0.00E+00	1.35E-03	1.08E-03	3.40E-08	0.00E+00	0.00E+00	1.08E-03
	Phosphate	1.14E-08	4.58E-10	3.02E-07	0.00E+00	3.14E-07	9.09E-09	3.66E-10	0.00E+00	0.00E+00	9.45E-09
	Phosphorus	8.40E-05	3.78E-06	1.25E-07	0.00E+00	8.79E-05	6.72E-05	3.02E-06	0.00E+00	0.00E+00	7.02E-05
Resource Energy (MJ/MWh)	Crude oil	4.16E+00	2.74E-01	1.21E+00	0.00E+00	5.64E+00	3.32E+00	2.19E-01	0.00E+00	0.00E+00	3.54E+00
	Hard coal	2.05E+01	1.11E+00	4.06E+00	0.00E+00	2.56E+01	1.64E+01	8.88E-01	0.00E+00	0.00E+00	1.72E+01
	Lignite	8.04E-03	3.95E-04	1.63E-01	0.00E+00	1.71E-01	6.43E-03	3.15E-04	0.00E+00	0.00E+00	6.74E-03
	Natural gas	1.45E+04	7.02E-01	1.22E+01	0.00E+00	1.46E+04	1.16E+04	5.61E-01	0.00E+00	0.00E+00	1.16E+04
	Uranium	4.78E-02	2.32E-03	3.77E-01	0.00E+00	4.27E-01	3.82E-02	1.85E-03	0.00E+00	0.00E+00	4.01E-02
	Total resource energy	1.46E+04	2.09E+00	1.81E+01	0.00E+00	1.46E+04	1.16E+04	1.67E+00	0.00E+00	0.00E+00	1.16E+04
Energy Return on Investment		N/A	N/A	N/A	N/A	32.8%	N/A	N/A	N/A	N/A	0.447