Final Report
Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water

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Consortium of State Oilheat Associations Greenhouse Gas Project

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EXECUTIVE SUMMARY

Natural gas and heating oil can both provide space heating and hot water services in the residential sector. Choosing a specific energy source for these services has significant implications in terms of energy efficiency, economics and environmental impact. While the ultimate energy choice is made by builders and consumers, and most often based on economics, this choice is also influenced by perceptions of how efficiently, or inefficiently, our energy resources are being used and how the choice might impact the environment, including the release of greenhouse gases (GHG) into the atmosphere. This analysis compared the relative energy resources consumed and GHG impacts associated with natural gas (pipeline and LNG), heating oil (current product and ultra low sulfur), and biofuels (B5, B20 and B100) used for residential space heating boilers and water heating. Consideration was given not only to impacts at the point of ultimate energy consumption -- i.e., the efficiency of use at the residence -- but also to those impacts associated with the production, conversion, transmission and distribution of energy to the household. The analysis presents the total resource energy requirements and fuel cycle GHG emissions for heating services supplied by high efficiency natural gas, heating oil and biofuel products based on their typical usage in five market demand regions of the United States:

- Oregon-Washington (Pacific Northwest)
- Upper Midwest
- New England
- New York, Pennsylvania, New Jersey
- Virginia-Maryland.

The three main GHG emissions from the oil and natural gas fuel cycle are methane, carbon dioxide, and nitrous oxide. While CO2 is considered the primary contributor to global warming, methane and nitrous oxide also have significant global warming potential. The analysis estimated the GHG emissions of each fuel at each stage of the fuel cycle, from well to burnertip, in terms of CO2 equivalent, or CO_2e [1]. The individual GHG sources along the fuel cycle were classified into three categories: vented, fugitive, and combustion emissions.

- Vented emissions are the designed and intentional equipment vents to the atmosphere. For example, pneumatics devices are engineered to leak small amounts of natural gas when in operation and these emissions are classified as vents.
- Fugitive emissions are the unintentional equipment leaks. For example, leaks from flanges and valves at a wellhead are classified as fugitives, and
- Combustion emissions are the emissions associated with the combustion of fuel. Combustion emissions may be for either energy use or non-energy use. Energy use refers to any

[1] CO_2e (CO_2 equivalent) emissions include CO_2, N_2O and methane all calculated for their global warming potential (GWP) in terms of a CO_2 baseline = 1. This analysis used the recognized 100 year GWP time horizon in evaluating the relative GWP of methane (23 x CO_2) and nitrous oxide N_2O (296 x CO_2)

combustion of fuel where energy is extracted for beneficial use, such as natural gas used as fuel and combusted in compressor engines and heaters. Non-energy combustion refers to any combustion of fuel in flares where there is no energy extraction.

Energy consumption at each stage of the fuel cycle was also estimated for each fuel based on the best available resources. Estimates for both GHG emissions and energy consumption were made for 2006 and 2020 in order to reflect changing trends in fuel supply regions, recovery and processing requirements, and new technologies.

The total energy use and GHG emissions of each fuel type (natural gas, heating oil, and biofuel blends) were compared for four different boiler systems, each providing space heating and hot water services to a standard home in each of the five market demand regions. This comparison considers not only the fuel cycle energy use and GHG emissions of each fuel up to the burner tip, but also reflects the efficiency of the heating equipment at the ultimate point of use.

The analysis underscores the importance of considering the total resource energy use and fuel cycle emissions impacts of ultimate fuel consumption. Significant energy is consumed, with resulting emissions of CO_2 and other greenhouse gases (GHG), during all stages of the fuel cycle including the extraction/production, processing, transmission, distribution, and ultimate combustion stages. As shown in **Tables ES-1** and **ES-2**, the fuel cycle emissions add 17 to 18 percent to the GHG emissions of heating oil combustion, and 25 to 30 percent to the GHG emissions of natural gas combustion at the burner tip (before end use equipment efficiencies).

Table ES-1 Summary of Heating Oil Fuel Cycle GHG Emissions for 2006 and 2020

Fuel Cycle Stage	OR- WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
2006 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)					
Exploration and Production	11.33	11.33	11.33	11.33	11.33
Transportation and Storage	0.86	1.74	2.45	2.45	2.45
Refining	15.10	15.84	14.93	14.93	14.93
Bulk Shipments from Refinery	0.31	0.05	0.31	0.08	0.15
Retail Delivery	0.54	0.54	0.54	0.54	0.54
Final Combustion	161.19	161.19	161.19	161.19	161.19
Total Fuel Cycle Emissions	189.32	190.70	190.75	190.52	190.59
Total Fuel Cycle Efficiency	86.5%	85.9%	85.6%	86.1%	86.5%
2020 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)					
Exploration and Production	12.17	12.17	12.17	12.17	12.17
Transportation and Storage	0.84	1.67	2.40	2.40	2.40
Refining	16.72	17.97	15.78	15.78	15.78
Bulk Shipments from Refinery	0.31	0.05	0.31	0.08	0.15
Retail Delivery	0.54	0.54	0.54	0.54	0.54
Final Combustion	161.19	161.19	161.19	161.19	161.19
Total Fuel Cycle Emissions	191.77	193.59	192.40	192.16	192.24
Total Fuel Cycle Efficiency	86.1%	85.7%	85.3%	85.8%	86.1%

Table ES-2 Summary of Natural Gas Fuel Cycle GHG Emissions for 2006 and 2020

Fuel Cycle Stage	OR- WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
2006 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)					
E&D	0.36	0.48	0.24	0.35	0.23
Production	14.65	15.61	10.72	12.32	9.20
Processing	4.46	5.48	4.94	6.58	5.49
Liquefaction	0.00	0.00	2.39	0.50	1.61
Shipping	0.00	0.00	0.66	0.20	0.48
Regasification	0.00	0.00	0.38	0.08	0.26
Transmission	7.86	8.75	10.47	10.07	9.53
Distribution	3.11	4.55	4.77	5.72	2.68
Final Combustion	117.06	117.06	117.06	117.06	117.06
Total Fuel Cycle Emissions	**147.52**	**151.94**	**151.64**	**152.88**	**146.54**
Total Fuel Cycle Efficiency	**91.6%**	**90.5%**	**86.8%**	**88.6%**	**88.6%**
2020 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)					
E&D	0.37	0.37	0.15	0.24	0.16
Production	19.94	17.41	9.07	11.30	8.53
Processing	6.46	6.34	8.12	8.99	8.35
Liquefaction	0.00	0.00	5.18	2.79	4.49
Shipping	0.00	0.00	3.73	2.72	3.48
Regasification	0.00	0.00	0.94	0.50	0.81
Transmission	6.68	7.73	6.69	8.69	6.91
Distribution	2.21	3.24	4.39	3.82	1.57
Final Combustion	117.06	117.06	117.06	117.06	117.06
Total Fuel Cycle Emissions	152.72	152.15	155.33	156.11	151.37
Total Fuel Cycle Efficiency	90.6%	90.0%	83.7%	84.6%	84.3%

The fuel cycle energy efficiency, a measure of the resource energy required to extract, process and deliver the fuel from well to burner tip (before end-use equipment efficiencies) is also a critical parameter. Fuel cycle efficiencies for heating oil remain in a fairly narrow band, ranging from 85.6 to 86.5 percent, with little change from 2006 to 2020. Fuel cycle energy efficiency for natural gas spans a broader range, ranging from 90.5 to 91.6 percent for natural gas delivered to Oregon-Washington and the Upper Midwest, and from 86.8 to 88.6 percent for natural gas delivered to the three market regions more distant from supply resources. These efficiencies are reduced in 2020, reflecting expected changes in the resource base of natural gas and particularly the reliance on LNG as a significant component of natural gas supply to the Northeast and Mid-Atlantic regions of the country. 2020 fuel cycle energy efficiency ranges from 90.0 to 90.6 percent for Oregon-Washington and the Upper Midwest and from 83.7 to 84.6 percent for New England, NY-NJ-PA and VA-MD.

The analysis also illustrates the importance of considering the efficiencies of end-use equipment in comparing fuel choices. Based on the 2006 resource and supply base, heating oil potentially produces 28 to 30 percent more GHG emissions than natural gas at the burner tip (before end-use equipment efficiencies) in terms of lb CO_2e/MMBtu for the regions under consideration; this changes to 25 to 28 percent in 2020. When compared on the basis of delivered energy services (including the efficiencies of end-use equipment), the incremental GHG emissions of heating oil over natural gas can be as low as 6 percent for the heating equipment most likely to be used in the marketplace (high efficiency, non-condensing units).

Finally, the analysis demonstrates that the evolution in fuel supplies over time should also be considered in comparing fuel choices. The potential use of biofuel blends can significantly alter the relative GHG emissions profiles of natural gas and heating oil. B20, a blend of 20 percent biofuel and 80 percent low sulfur heating oil, is estimated to have total GHG emissions for delivered energy services (including end-use equipment efficiencies) on a par with delivered natural gas in 2020. B20 can have up to 12 percent lower GHG emissions than LNG, the marginal natural gas supply option for the Northeast and Mid-Atlantic regions, depending on which heating equipment is considered.

Figures ES-1 and **ES-2** illustrate this ultimate end-use comparison for the New England region as an example. New England is expected to experience significant changes in its natural gas supply mix over the period of the analysis. The region will see a decrease in natural gas currently supplied from Western Canada and the Gulf Coast, and increases in supply from Eastern Canada and, most significantly, increased LNG imports into terminals in New England and Canada; LNG is estimated to supply 54 percent of the region's natural gas in 2020. The figures show the annual full fuel cycle GHG emissions estimates (including energy use along the fuel cycle and end use equipment efficiency) for the region based providing heating and hot water services to a modeled 2,500 square foot house in for average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. As shown, conventional heating oil produces anywhere from 11 to 26 percent more GHG emissions than natural gas on an annual basis in 2006, depending on heating equipment selected. However, in 2020, B20 has lower emissions than delivered natural gas for both average and high efficiency, non-condensing systems. B20 has lower fuel cycle GHG emissions than the marginal LNG supply for the region for all heating systems except for the condensing units with radiant floor distribution.

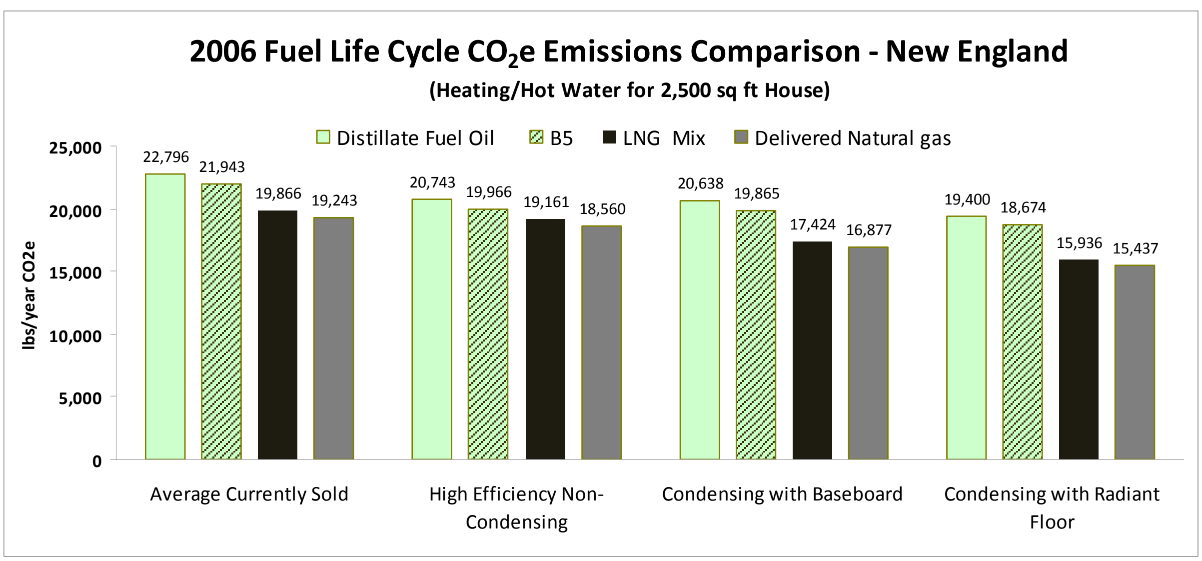

Figure ES-1 Heating System Emissions Comparison for New England in 2006

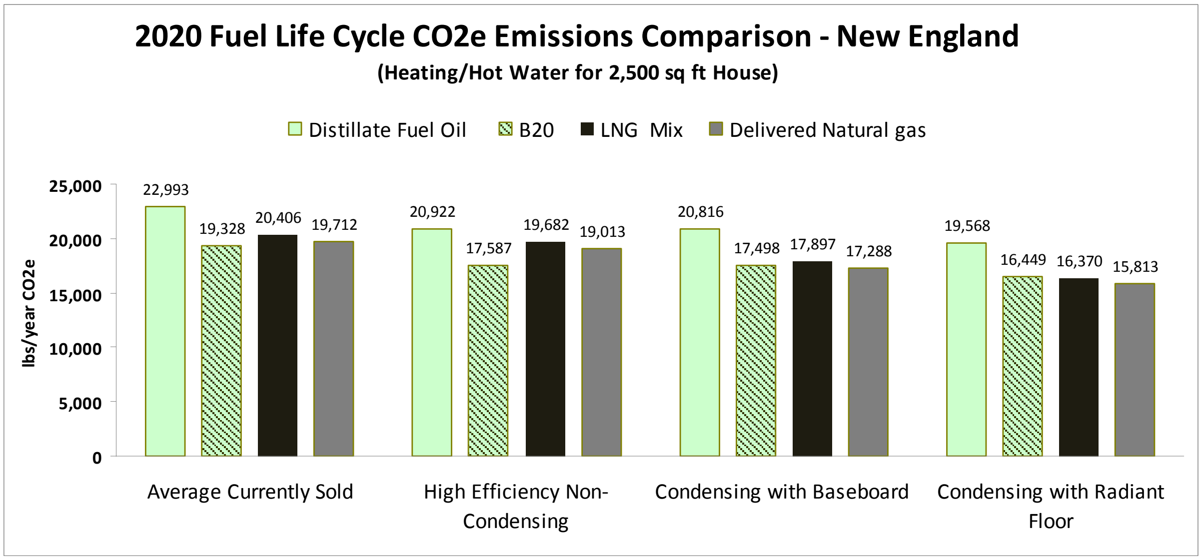

Figure ES-2 Heating System Emissions Comparison for New England in 2020

1
INTRODUCTION

Natural gas, LNG, heating oil and biofuels can all provide space heating and hot water services in the residential sector. Choosing a specific energy source for these services has significant implications in terms of energy efficiency, economics and environmental impact. While the ultimate energy choice is made by builders and consumers, and most often based on economics, this choice is also influenced by perceptions of how efficiently, or inefficiently, our energy resources are being used and how the choice might impact the environment, including the release of greenhouse gases into the atmosphere. Focusing on sustainability in the built environment requires life cycle assessments of building products and equipment. Sustainable energy production and consumption should also require life cycle, or fuel cycle, assessments from wellhead to burner tip. It is important, therefore, that consumers, builders and policy makers have the most accurate estimates of energy consumption, energy efficiency and environmental impacts when making energy choices for their homes. However, most efficiency standards and regulations that pertain to residential space heating and hot water appliances are “site-based” - that is, they only consider the impacts at the site where the energy is ultimately delivered. Because the energy consumption and environmental impacts along the total energy production and supply chain are not included, reliance on site-based data can lead to inaccurate comparisons and may result in higher energy resource consumption as well as higher levels of pollution.

Total resource energy analysis and fuel cycle emissions analysis are more comprehensive and accurate methods to assess the total energy and emissions impacts of fuel consumption at the point of use. These methods examine all energy consumption and emissions impacts associated with fuel use, including those from the extraction/production, processing, transmission, distribution, and ultimate energy consumption stages of the fuel cycle. Site energy analysis only takes into consideration the ultimate consumption stage. Significant energy is consumed, with resulting emissions of CO_2 and other greenhouse gases (GHG), during all stages of energy use.

Greenhouse gas emissions are usually reported in metric tons of CO_2 equivalent (CO_2e). CO_2e is a measure used to compare different types of greenhouse gas emissions by converting all the various greenhouse gases to a carbon dioxide equivalent. This conversion to a common metric is accomplished using each gas’s Global Warming Potential (GWP). GWP values have been established for the various GHGs by the Intergovernmental Panel on Climate Change (IPCC), the premier inter-governmental organization examining climate change and its impact on society. ICF based its calculations in this analysis on the IPCC convention of using the GWP values over a 100 year timeframe – i.e., the impact each greenhouse gas is expected to have in the atmosphere over 100 years.[2]

[2] CO_2e (CO_2 equivalent) emissions include CO_2, N_2O and methane all calculated for their global warming potential (GWP) in terms of a CO_2 baseline = 1. This analysis used the recognized 100 year GWP time horizon in evaluating the relative GWP of methane (23 x CO_2) and nitrous oxide N_2O (296 x CO_2)

The purpose of this analysis is to compare the relative energy resources consumed and GHG impacts associated with natural gas (pipeline and LNG), heating oil (current product and ultra low sulfur), and biofuels (B5, B20 and B100) used for residential space heating boilers and water heating. Consideration is given not only to impacts at the point of ultimate energy consumption -- i.e., the residence -- but also to those impacts associated with the production, conversion, transmission and distribution of energy to the household. The analysis compares the total source energy requirements and life cycle CO_2e[3] emissions for heating services supplied by high efficiency natural gas, heating oil and biofuel products based on their typical usage in five market demand regions of the United States:

- Oregon-Washington (Pacific Northwest)
- Upper Midwest such as Milwaukee
- New England
- New York, Pennsylvania, New Jersey
- Virginia-Maryland.

Analytic Approach

The three main GHG emissions from the oil and natural gas fuel cycle are methane, carbon dioxide, and nitrous oxide. These GHGs were estimated for each stage of the fuel cycle at the lowest level of aggregation, i.e. at an individual source level. For example, emissions were estimated from individual sources like compressors, engines, wellheads, etc for each stage in the fuel cycle. There are a few exceptions to this rule such as offshore platform emissions, which are estimated on a per platform basis and emissions from fuel combustion in production and processing, which are estimated at a national level. These exceptions are discussed in the individual sections of the report where appropriate.

The individual GHG sources along the fuel cycle are classified into three broad categories: vented, fugitive, and combustion emissions.

- Vented emissions are the designed and intentional equipment vents to the atmosphere. For example, pneumatics devices are engineered to leak small amounts of natural gas when in operation and these emissions are classified as vents.

- Fugitive emissions are the unintentional equipment leaks. For example, leaks from flanges and valves at a wellhead are classified as fugitives, and

- Combustion emissions are the emissions associated with the combustion of fuel. Combustion emissions may be for either energy use or non-energy use.

[3] CO_2e (CO_2 equivalent) emissions include CO_2, N_2O and methane all calculated for their global warming potential (GWP) in terms of a CO_2 baseline = 1. This analysis used the recognized 100 year GWP time horizon in evaluating the relative GWP of methane (23 x CO_2) and nitrous oxide N_2O (296 x CO_2)

Energy use combustion refers to any combustion of fuel where energy is extracted for beneficial use, such as natural gas used as fuel and combusted in compressor engines and heaters. Non-energy combustion refers to any combustion of fuel in flares where there is no energy extraction.

Emissions from the ultimate combustion of natural gas and oil as fuel are of two types: combusted emissions and un-combusted emissions. Typically, in any kind of fuel combustion the combustion process is not 100 percent efficient. The emissions from the combusted portion of the fuel are referred to as combustion emissions. For example, CO_2 and N_2O emissions are created in the portion of natural gas used as combustion fuel. There are no combusted CH_4 emissions. Un-combusted emissions are gases that pass through the combustion process without any chemical change. For example, some portion of CH_4 and CO_2 present in natural gas used as combustion fuel pass through as un-combusted emissions. There are no un-combusted N_2O emissions.

Energy consumption at each stage of the fuel cycle was also estimated for each fuel based on the best available resources. Estimates for both GHG emissions and energy consumption were made for 2006 and 2020 in order to reflect changing trends in fuel supply regions, recovery and processing requirements, and new technologies.

Finally, the total energy use and GHG emissions of each fuel type (natural gas, heating oil, and biofuel blends) are compared for four different boiler systems, each providing space heating and hot water services to a standard home in each of the five market demand regions. This comparison includes not only the fuel cycle energy use and GHG emissions of each fuel up to the burner tip, but also reflects the efficiency of the heating equipment at the ultimate point of use.

2
HEATING OIL FUEL CYCLE ANALYSIS

Introduction

This section describes the results and analytical approach of a full fuel cycle analysis of the energy used and GHG emissions associated with supplying home heating oil to five designated locations throughout the United States.

Analytical Framework

The home heating oil that is delivered to final customers in the United States is the product of a complex series of interrelated activities that, in part, begins on the other side of the world. Each of these activities requires energy and emits greenhouse gases (GHG). Fuel cycle analysis is the quantification of the energy and emissions of all of these activities that is required to deliver a unit of fuel to the customer. The oil fuel cycle consists of the following general activities

- **Exploration and production –** Energy is consumed in the process of exploring for oil, drilling wells, bringing the oil to the surface, and in separating water, other products, and contaminants from the crude oil. The energy and emissions for E&P activities are based on statistics for U.S. production. Exploration and production of imported oil, which makes up more than 50 percent of crude oil used in the U.S., is assumed to have the same energy and emissions "costs" as defined for domestic production.

- **Transportation and Storage –** Imported oil must be brought in to the U.S. This process is primarily by ocean tanker, though there is a small amount of oil that enters the country from Canada and Mexico by pipeline or rail transport. Crude oil produced in the U.S. and imports both need to be transported to refineries. This transportation is a mix of pipeline, barge, and rail from domestic production facilities and from import receiving terminals.

- **Oil Refining –** Crude oil is converted to home heating oil along with an entire slate of other refined products. The energy and emissions associated with oil refining are characterized. In addition, the overall energy and emissions associated with U.S. oil refining are allocated on a unit energy basis to home heating oil based on an assessment of the specific refining steps required to produce that product. There are refined products that are imported into the U.S. for delivery to storage or blending facilities. These products, refined in other countries, are assumed to have the same unit energy and emissions values as estimated for U.S. refining.

- **Bulk Shipments from Refineries –** After refining, oil products are bulk shipped to storage and distribution terminals throughout the U.S. Again, these shipments include pipeline, barge, and rail shipments.

- **Retail Delivery –** Final distribution of home heating oil to customers is undertaken by oil delivery trucks. At each stage of the fuel cycle there are individual transport and storage steps. Each of the three separate transportation steps are discussed in the Section on *Transport and Storage*.

Estimates of energy and emissions are made for five home heating oil market areas:

- Oregon-Washington (Pacific Northwest)
- Upper Midwest such as Milwaukee
- New England
- New York, Pennsylvania, New Jersey
- Virginia-Maryland.

Due to data constraints, it was not possible to precisely trace the exact pathways that heating oil delivered to each of these markets takes. Regional detail was based, at each processing step, on the availability of data.

- Exploration and production is based on the five Petroleum Administration for Defense Districts (PADD). (See Map **Figure 1**.) These districts are defined as follows:
  - PAD District I (East Coast) is composed of the following three sub-districts:
    - Sub-district IA (New England): Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont.
    - Sub-district IB (Central Atlantic): Delaware, District of Columbia, Maryland, New Jersey, New York, Pennsylvania.
    - Sub-district IC (Lower Atlantic): Florida, Georgia, North Carolina, South Carolina, Virginia, West Virginia.
  - PAD District II (Midwest): Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Ohio, Oklahoma, Tennessee, Wisconsin.
  - PAD District III (Gulf Coast): Alabama, Arkansas, Louisiana, Mississippi, New Mexico, Texas.
  - PAD District IV (Rocky Mountain): Colorado Idaho, Montana, Utah, Wyoming.
  - PAD District V (West Coast): Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington.
- The refining step is also analyzed by PADD based on the energy consumed by refineries and the product slates in each PADD. The current oil fuel cycle is based on current refinery practice (2006) in the production of conventional home heating oil. The forecast for 2020 is based on the assumption of additional processing to produce low sulfur specification home heating oil. Standards have already emerged in certain states to bring home heating oil in line with on-road diesel to a 500 ppmw sulfur limit. By 2020, it is assumed that ultralow sulfur fuel will be required with sulfur limits of 50 ppmw.

- The transport and storage analysis is based on a regional estimation of distances by modes of travel with national estimates of energy intensity per mile for each travel mode.
    - Transport of imported oil is based on estimates of distances for ocean going tankers to each of the receiving PADDs.
    - Bulk transport to refineries is estimated by PADD. Inter-PADD shipments of crude oil are characterized and distances estimated based on a typical refinery center with the PADD.
    - Transport of refined products is estimated for each final market region based on the estimated distance of travel from a nearby refinery center.
    - Retail delivery is estimated based on a single model of truck delivery efficiency and average distance that is used for each market region.

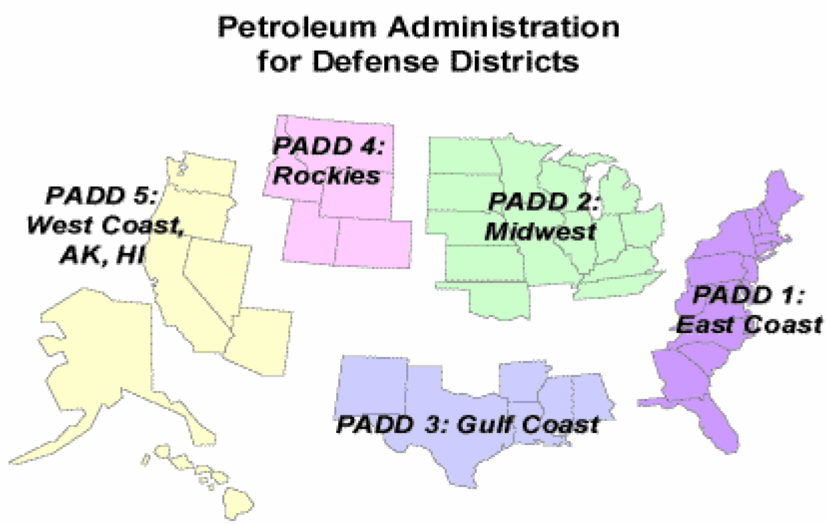

Figure 1 PAD Districts

Data for the analysis came from a number of sources as follows:

- Basic data on energy flows in the oil industry and energy consumption by type within the refining industry come from the Energy Information Administration.[4] EIA provides statistics at the PADD level, in some cases at a finer level, for crude oil production, imports and exports, refining input-output, refining energy consumption by type, shipments between PADDs, and consumption of products. These energy flows provided the basic oil sector energy balance for the base year of 2006.
- A recently released API study[5] provided a detailed analysis of GHG emissions from upstream and downstream oil processing including a forecast of activity levels and projected emissions for 2020. The report provides a definitive update of methane emissions from each of the oil and gas

[4] EIA Online Petroleum Navigator. http://tonto.eia.doe.gov/dnav/pet/pet_sum_top.asp
[5] Impact Assessment of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry, Volume I: Report, ICF International, Inc., American Petroleum Institute, December, 2007.

processing stages. The API report did not provide a complete analysis of the base year 2006 nor did it address all of the combustion related emissions in the oil sector.

- The Center for Transportation Research at Argonne National Laboratory has developed a model of transportation fuel cycle energy consumption and emissions called GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation).[6] The upstream portions of the petroleum fuel cycle were utilized as needed to fill in gaps in the API analysis and to provide unit factors for use with the EIA energy usage estimates.
- Basic conversion factors to convert fuel and power in physical units to energy content and GHG emissions were taken from EPA.[7]

Oil Exploration and Production

Oil exploration and production (E&P) includes well drilling, oil extraction, oil gathering through gathering pipes, crude treatment in production fields, and crude storage in production fields. Oil can be produced by using conventional extraction methods, which rely on the natural pressure of underground oil reservoirs; artificial lift methods (such as surface or subsurface pumps); or enhanced oil recovery methods, which are often used to modify thick, highly viscous crude before it can be extracted from the ground. Use of enhanced oil recovery methods can significantly increase the energy required for crude recovery. Three general enhanced oil recovery methods can be used:

- Thermal recovery – injecting steam into the reservoir is used for extraction of heavy oil
- Chemical flooding – injecting a mixture of chemicals and water into a reservoir in order to generate a fluid
- Gas displacement – injecting gases (mainly CO_2) into a reservoir to sweep crude toward a production well. CO_2 injection has value as a method of carbon sequestration.

Crude oil is brought to the surface with a mixture of oil, water, and gas, which must be separated from the crude in on-site treatment facilities before the crude can be put through pipelines. On-site treatment facilities usually include oil/gas separators, oil/water separators (often called heater treaters), oil storage tanks, and produced water reservoirs.

The three main GHG emissions from the oil E&P activities are methane, carbon dioxide, and nitrous oxide. The individual sources are classified into three broad categories: vented, fugitive, and combustion emissions, using the framework established by API.

- Combustion emissions are the emissions associated with the combustion of fuel for engines, heaters, steam production, and gas flaring. Combustion emissions may be for either energy use or non-energy use, such as flaring.

[6] GREET (Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation) Version 1.8a, Argonne National Laboratory.
[7] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, U.S. Environmental Protection Agency, (EPA 430-R-07-002), April 15, 2007.

- Vented emissions are the designed and intentional equipment vents to the atmosphere. Venting occurs from oil tanks, pneumatic devices, pumps, equipment blowdown, well completions, well workovers, and other processes.
- Fugitive emissions are unintentional equipment leaks. These leaks occur at the wellhead, from separators, heaters, crude headers, floating CO_2 roof tanks, and compressors.

Energy use and GHG emissions are calculated on a national basis from a combination of sources. The unit energy use estimates (Btu/MMBtu of oil produced) come from the Argonne GREET model.[8] Estimates for future oil production, methane emissions, and flaring are taken from the recent API study.[9] These results are combined for total E&P related emissions. GREET does not provide regional detail. The API report does report results by PADD, but it was found that the analysis was done on a national basis and the PADD allocations are not consistent with current PADD production figures. Therefore, only a national estimate was made for this analysis that was applied to each of the five demand regions.

Table 1 shows the estimated unit energy consumption and emissions for oil exploration and production. As previously stated the source for the unit energy consumption factors comes from the Argonne GREET model.[10] The supporting GREET documentation, only available for an earlier model release, contains a section documenting the assumptions related to energy use and emissions associated with oil recovery.[11] The CO_2 emissions factors come from EPA.[12] N_2O is a very minor share of emissions. It was assumed that the N20 emissions converted to CO_2 equivalence are in the ratio of 0.007 to 1 compared to the CO_2 emissions, or 23.5 ppm multiplied by a GWP factor of 296. This ratio was calculated from the GREET emissions factors and applied for all estimates of N20 emissions in CO_2 equivalence.

Table 2 shows the total emissions for current production and estimated 2020 production levels. The 2006 combustion emissions are based on the total production times the unit emissions shown in Table 1. Methane emissions are taken from the API analysis for both 2006 and 2020. The API analysis did not estimate unit emissions, only totals and did not completely represent combustion emissions which is why the GREET combustion factors were used. The total combustion related emissions for 2006 are based on the total oil production and the unit emissions estimated in Table 1. The 2020 combustion emissions, not estimated directly by either GREET or API, were assumed to be proportional to the 2006 and 2020 outputs, from API, with an additional energy intensity of 7.5 percent added to reflect the greater difficulty of extracting oil from depleting reservoirs. The N_2O emissions are a simple ratio of the CO_2 emissions as described above.

Table 3 shows the unit energy use and GHG emissions for 2006 and 2020. The 2006 energy use is summarized from Table 1. The unit energy estimates for 2020 are based on the combustion emissions shown in Table 2 allocated to the three categories of energy use in the same ratio as 2006. The unit emissions are figured similarly from the data in Table 1 and Table 2.

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[8] GREET (Version 1.8a, Argonne National Laboratory.
[9] API, op cit.
[10] GREET 1.8a, Petroleum Tab, Table 3: "Calculations of Energy Consumption and Emissions for Petroleum Fuels By Stage," Argonne National Laboratory.
[11] M.D. Wang, GREET 1.5: Transportation Fuel Cycle Model, Volume 1: Methodology, Development, Use, Results, Argonne National Laboratory, 1999.
[12] U.S. Inventory of Greenhouse Gas Emissions and Sinks: Fast Facts, U.S. EPA.

Table 1 Estimate of Energy Use and Combustion Emissions for Crude Oil Exploration and Production

	Petroleum Product Use	Other Energy Use	Electric Use	Total Energy Use	Unit GHG Emission Factors	Comb. CO_2	N_2O
Energy Use	Btu/MMBtu				lb CO_2e / MMBtu		
Crude oil	204			204	160	0.03	0.00
Residual oil	204			204	175	0.04	0.00
Diesel fuel	3,057			3,057	161	0.49	0.00
Gasoline	408			408	158	0.06	0.00
Natural gas		12,635		12,635	117	1.48	0.01
Electricity			3,872	3,872	420	1.62	0.01
Feed loss	28			28	160	0.00	0.00
Total Productive Energy	3,901	12,635	3,872	20,408		3.73	0.03
Natural gas flared		16,800		16,800	117	1.97	0.01
Total Combustion/Energy	3,901	29,435	3,872	37,208		5.70	0.04

Source: Argonne, GREET 1.8a

Table 2 Total Estimated GHG Emissions for Oil Sector E&P

Estimated Emissions Million Metric Tons CO_2e	Methane Emissions	CO_2 Combustion	Nitrous Oxide Emissions from Energy Combustion	Total	Production MM bbl/y
2006	27.80	28.4	0.02	56.17	1891
2020	27.15	26.9	0.02	54.10	1672

Source: Production and methane emissions from API, combustion related emissions calculated from GREET energy factors and API estimated production

Table 3 Unit E&P Energy Use and Emissions for 2006 and 2020

Fuel Cycle Efficiency	Petroleum Product Use	Other Energy Use	Electric Use	Total Energy Use	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	Btu/MMBtu				lb CO_2e/MMBtu					
2006	3,901	29,435	3,872	37,208	0	4.07	5.59	0.04	1.62	11.33
2020	4,191	31,626	4,160	39,978	0	4.38	6.00	0.04	1.75	12.17

Note: due to data limitations, no regional differences were assumed in these results.

Oil Refining

The largest source of heating oil fuel cycle energy use and GHG emissions comes from the refinery sector. Refineries require heat for distillation and other thermal processing steps (hydro-treating, hydro-cracking, coking, etc.). Fuel is also used, though not technically combusted, in the process of making hydrogen as a feedstock for the refining process. Emissions are also produced by non-combustion processes such as crude cracking (both thermal and catalytic), hydrocarbon reforming, catalyst regeneration, sulfur recovery, and blowdown systems. Fugitive emissions are also generated during various refining processes.

2006 Refining Energy Use and Emissions

For the current year (2006) analysis, specific energy use and refinery output data is based on the Energy Information Administration (EIA.)[13] The energy use and GHG emissions are characterized by PADD. These are termed Supply PADD regions. Refined oil products are shipped between PADDs such that the oil used in a given region may come from two or more neighboring PADD supply regions. These movements are characterized from the EIA data, and the energy use contained in refined oil products is estimated for the refined oil consumed in each PADD, termed PADD demand regions.[14] **Table 4** shows the 2006 fuels and energy consumed at U.S. refineries in physical units by PADD based on EIA data as described in the introductory description of sources. **Table** 5 converts these values to common energy units. Energy content by fuel comes from EIA values. Electricity is valued at its primary energy source basis, assuming 10,300 Btu/kWh. Steam is valued at 1,000 Btu/lb. Over 70 percent of the energy required for petroleum refining comes from the use of intermediate oil products produced at the refinery. Refineries require energy equal to between 8.9 to 10.2 percent of the energy content of the output product fuel, except in PADD 5 where the value is much higher at 14.4 percent. PADD 5 refinery energy use is higher than in the rest of the country because of the high proportion of heavy California crude that is processed and the aggressive product slate that pushes this heavy end toward the valuable transportation fuels. There is no heating oil market in California and there is virtually no residual oil market, so these products are forced to the lighter ends by additional cracking, hydrotreating, and coking. These energy intensive California refineries make up 70 percent of the total PADD 5 refining capacity.

[13] EIA online Petroleum Navigator, http://tonto.eia.doe.gov/dnav/pet/pet_sum_top.asp
[14] The term supply and demand when added to PADD regions refers only to how the data are used in this study. Supply refers to the energy used for oil refined in the PADD. Demand refers to the weighted average of the oil used in the PADD

Table 4 Fuel/energy Consumed at Refineries 2006 (Physical Units)

Refinery Energy Consumption	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.
	Thousand Barrels (except where noted)					
Liquefied Petroleum Gases	722	779	359	24	2,291	4,175
Distillate Fuel Oil	366	50	86	0	253	755
Residual Fuel Oil	1,146	163	4	167	727	2,207
Still Gas	22,317	50,213	111,798	8,208	45,700	238,236
Petroleum Coke	12,812	17,342	41,299	2,828	15,371	89,652
Other Petroleum Products	141	1,686	1,300	502	1,700	5,329
Natural Gas (Million Cubic Feet)	35,603	106,480	395,980	21,585	123,271	682,919
Coal (Thousand Short Tons)	33	8	0	0	0	41
Purchased Electricity (Million Kilowatt-hours)	3,520	9,875	16,620	1,601	4,976	36,592
Purchased Steam (Million Pounds)	4,912	5,033	34,738	952	17,956	63,591

Source: EIA

Table 5 Fuel Consumed at Refineries 2006 (Billion Btu)

Refinery Energy Consumption	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.
	Billion Btu					
Liquefied Petroleum Gases	2,770	2,988	1,377	92	8,788	16,015
Distillate Fuel Oil	2,132	291	501	0	1,474	4,398
Residual Fuel Oil	7,205	1,025	25	1,050	4,571	13,875
Still Gas	140,307	315,689	702,874	51,604	287,316	1,497,790
Petroleum Coke	80,549	109,029	259,647	17,780	96,637	563,642
Other Petroleum Products	818	9,779	7,540	2,912	9,860	30,908
Natural Gas	36,671	109,674	407,859	22,233	126,969	703,407
Coal	1	0	0	0	0	1
Purchased Electricity	36,256	101,713	171,186	16,490	51,253	376,898
Purchased Steam	4,912	5,033	34,738	952	17,956	63,591
Total Refining Energy	311,620	655,221	1,585,747	113,112	604,824	3,270,525
Total Refinery Output	3,507,351	6,408,578	16,370,880	1,215,259	4,210,856	31,712,924
Energy Used/Energy Out	8.9%	10.2%	9.7%	9.3%	14.4%	10.3%

Table 6 converts the energy consumption at refineries by PADD into equivalent greenhouse gas (GHG) emissions from combustion. Electricity is valued at a source energy basis (10,300 Btu/kWh) and steam is valued at 1,000 Btu/lb of steam.

Table 6 Refinery Energy Use Greenhouse Gas Emissions by PADD

Refinery Energy Consumption	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.
	Million Metric Tons CO_2 Equivalent					
Liquefied Petroleum Gases	0.175	0.189	0.087	0.006	0.556	1.013
Distillate Fuel Oil	0.156	0.021	0.037	0.000	0.108	0.322
Residual Fuel Oil	0.573	0.082	0.002	0.084	0.364	1.104
Still Gas	9.008	20.269	45.128	3.313	18.447	96.165
Petroleum Coke	8.226	11.134	26.515	1.816	9.868	57.558
Other Petroleum Products	0.059	0.709	0.546	0.211	0.714	2.239
Natural Gas	1.946	5.819	21.640	1.180	6.737	37.320
Coal	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Electricity	2.288	6.419	10.803	1.041	3.234	23.785
Purchased Steam	0.326	0.334	2.304	0.063	1.191	4.217
Total	22.757	44.974	107.061	7.712	41.219	223.723
Total Refinery Output (Billion Btu)	3,507,351	6,408,578	16,370,880	1,215,259	4,210,856	31,712,924
lb CO_2 Equiv/MMBtu Refinery Out	14.30	15.47	14.42	13.99	21.58	15.55

The GHG refinery emissions by PADD cannot be used directly in a demand side analysis because each demand center uses refined oil products from one or more PADDs. Therefore, the destination of refined oil products from each PADD must be defined and the weighted average energy and GHG emissions values applied to that demand region. **Table** 7 shows the movements of refined oil products between PADDs for 2006. These movements are shown as percentages. For example, in PADD 1, 35.8 percent of the refined oil used comes from PADD 1 refineries, 63.3 percent comes from PADD 3 refineries, and only 0.9 percent comes from PADD 2 refineries. In the Table, the first block of percentages shows where the refined products come from, and the second block of percentages shows where the oil refined in that PADD goes for final consumption. These inter-PADD shipments are also tracked when defining the transportation energy and GHG impacts.

The resulting energy and GHG emissions values based on the demand in each PADD are shown in **Table 8** and **Table 9** respectively. These are all combustion related emissions. Steam and electric use are characterized in the summary as indirect emissions. Methane and noncombustion CO_2 emissions were based on the API estimates for 2020 that were allocated proportionally to the 2006 combustion emissions.

Table 7 Share of Refinery Products Used/Shipped by PADD (thousand bbl)

2006 Production and Shipments/Use by PADD	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.
	Thousand Barrels (except where noted)					
Total Production	624,403	1,146,193	2,963,869	215,405	736,600	5,686,470
Shipments/Use by PADD						
PADD 1	502,653	12,926	887,446			1,403,025
PADD 2	121,680	1,055,542	365,779	21,007		1,564,008
PADD 3	70	68,528	1,664,959	48,649		1,782,206
PADD 4		9,197	13,359	133,856		156,412
PADD 5			32,326	11,893	736,600	780,819
Shipments/Use by PADD (%)	% of PADD product demand from each PADD Supply Region					
PADD 1 (Northeast Demand)	35.8%	0.9%	63.3%	0.0%	0.0%	100%
PADD 2 (Upper Midwest Demand)	7.8%	67.5%	23.4%	1.3%	0.0%	100%
PADD 3	0.0%	3.8%	93.4%	2.7%	0.0%	100%
PADD 4	0.0%	5.9%	8.5%	85.6%	0.0%	100%
PADD 5 (Northwest Demand)	0.0%	0.0%	4.1%	1.5%	94.3%	100%
Shipments/Use by PADD (%)	Allocation shares of PADD Supply by PADD Demand Region					
PADD 1 (Northeast Demand)	80.5%	1.1%	29.9%	0.0%	0.0%	112%
PADD 2 (Upper Midwest Demand)	19.5%	92.1%	12.3%	9.8%	0.0%	134%
PADD 3	0.0%	6.0%	56.2%	22.6%	0.0%	85%
PADD 4	0.0%	0.8%	0.5%	62.1%	0.0%	63%
PADD 5 (Northwest Demand)	0.0%	0.0%	1.1%	5.5%	100.0%	107%

Source: Inter-PADD shipments from EIA, percentages calculated

Table 8 Refinery Energy Consumption by Demand Region

Refinery Energy Consumption	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.
	Billion Btu					
Liquefied Petroleum Gases	2,676	3,471	973	87	8,808	16,015
Distillate Fuel Oil	1,870	746	299	5	1,479	4,398
Residual Fuel Oil	5,819	2,453	313	661	4,629	13,875
Still Gas	326,965	409,840	425,385	37,768	297,831	1,497,790
Petroleum Coke	143,816	149,881	156,400	13,094	100,451	563,642
Other Petroleum Products	3,026	10,379	5,478	1,922	10,103	30,908
Natural Gas	152,879	160,650	240,698	16,534	132,645	703,407
Coal	1	0	0	0	0	1
Purchased Electricity	81,590	123,468	105,974	11,835	54,030	376,898
Purchased Steam	14,412	9,972	20,031	789	18,387	63,591
Total	733,054	870,860	955,552	82,694	628,364	3,270,525
Billion Btu Product	7,797,530	8,724,114	9,854,384	880,391	4,456,505	31,712,924
Btu/MMBtu Refinery Out	94,011	99,822	96,967	93,929	140,999	103,129

Table 9 Refinery GHG by Demand Region

Refinery Energy Consumption	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.
	Million Metric Tons CO_2 Equivalent					
Liquefied Petroleum Gases	0.169	0.220	0.062	0.006	0.557	1.013
Distillate Fuel Oil	0.137	0.055	0.022	0.000	0.108	0.322
Residual Fuel Oil	0.463	0.195	0.025	0.053	0.368	1.104
Still Gas	20.993	26.314	27.312	2.425	19.122	96.165
Petroleum Coke	14.686	15.306	15.971	1.337	10.258	57.558
Other Petroleum Products	0.219	0.752	0.397	0.139	0.732	2.239
Natural Gas	8.111	8.524	12.771	0.877	7.038	37.320
Coal	0.000	0.000	0.000	0.000	0.000	0.000
Purchased Electricity	5.149	7.792	6.688	0.747	3.410	23.785
Purchased Steam	0.956	0.661	1.328	0.052	1.219	4.217
Total	50.883	59.817	64.575	5.636	42.812	223.723
Distillate Reduction Factor	7,824,542	8,722,330	9,939,200	872,295	4,354,556	31,712,924
lb CO_2e /MMBtu Refinery Out	14.34	15.12	14.32	14.24	21.67	15.55

Refinery Emissions Allocation for Home Heating Oil

The energy and GHG figures calculated in the preceding tables represent an average value for all of the products produced by refineries. The allocation of these values to a specific product or class of products should reflect, to the extent possible, the actual energy required to make that product. In developing the GREET model, Argonne used a linear program to assign energy and emissions factors to each product. **Table 10** shows the GREET unit emissions factors for gasoline, diesel fuel, and residual oil representing light end, middle, and bottom of the barrel respectively. Comparing these factors to the share of oil produced in each part of the barrel shows that the GREET allocation for diesel is nearly identical to a simple volume weighted average. First, total refinery output is split into three parts*: light fractions* (3.7 to 5.24 MMBtu/bbl), *middle fractions* (5.5 to 4.8 MMBtu/bbl), and *bottoms, resid and others* (over 6.0 MMBtu/bbl). Based on these definitions, 39 percent of the barrel output are in light fractions, 40 percent are in middle fractions such as home heating oil, and the remaining are bottoms, resid, and others. The GREET emissions factors for gasoline, diesel, and residual oil are shown to represent each of the three fractions of the barrel. Using these values to represent the slate of products in each fraction of the barrel, the light fractions account for 53 percent of emissions – much larger than their energy fraction. The heavy end of the barrel only accounts for 7.9 percent of emissions, much lower than their energy fraction. The emissions and energy percentage for the middle fraction, however, is virtually the same, whether one uses the GREET linear programming approach or the simple allocation based on unit energy. Based on this analysis, it was decided that the unit energy allocation basis was appropriate to use when comparing a middle of the barrel product like home heating oil.

The estimation of emissions from sulfur recovery plants, hydrogen production, flaring and other losses are based on the API 2020 forecast discussed in the next section.

Table 10 Energy and Emissions Allocation Factors

Refinery Fractions	U.S. Refinery Output	GREET Emissions Factors	Product Share	GREET Weighed Emissions Shares
	Billion Btu	g/MMBtu	%	%
Light Fractions	12,495	12,203	39.4%	52.0%
Middle of the Barrel	12,682	9,265	40.0%	40.1%
Bottoms, Resid, and other	6,535	3,532	20.6%	7.9%
Total	31,713	9,241	100.0%	100.0%

Non-Combustion Emissions and Flaring

In addition to the energy/combustion related GHG emissions, there were two additional sources of GHG emissions that were included: flaring and CO_2 produced from sulfur plant recovery. The estimates for these factors are shown in **Table 11**. These factors are based on the API analysis that was used for the 2020 analysis that is discussed in the next section. API did not forecast 2006 directly so a ratio of these emissions for 2020 compared to energy/combustion emissions was used.

Table 11 Estimated Factors for Flaring and Sulfur Plant Recovery

Process Units	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	U.S. Total
Primary Units						
Energy Combustion	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
From Flare/Loss	3.4%	3.9%	3.4%	3.5%	3.2%	3.5%
From Sulfur Plant Tail Gas	0.2%	0.3%	0.3%	0.1%	0.3%	0.3%
Total	103.5%	104.2%	103.8%	103.6%	103.5%	103.8%

2006 Refinery Energy and Emissions Summary by Demand Center

As previously stated, the refinery analysis was done by PADD region because this is the level of regional detail that has the most supporting data and analysis. This appropriate PADD energy use and emissions were applied to each of the five demand centers as shown in **Table 12.** This table combines the combustion and non-combustion emissions into one table. New England, NJ-NY-PA, and VA-MD are all based on the weighted average of refined oil products consumed in PADD 1. Upper Midwest is based on PADD 2. OR-WA was not based on PADD 5 because of the very large distortion caused by the California refineries. As previously described, the Northwest refineries are of average complexity so the energy and emissions are based on the average of PADDs 2 through 4.

Table 12 2006 Refining Energy Use and GHG Emissions by Demand Center

2006 Refining	Oil Product Use	Other Energy Use	Electric Use	Total Energy Use	Non-Comb. CO_2	Comb. CO_2	CH4*	N_2O	Indirect CO_2	Total GHG
	Btu/MMBtu				lb CO_2e/MMBtu					
OR- WA	62,193	21,787	4,044	88,023	0.51	12.80		0.09	1.71	15.10
Upper Midwest	66,112	19,558	4,690	90,359	0.64	13.18		0.09	1.94	15.85
New England	62,093	21,455	3,467	87,015	0.51	12.78		0.09	1.56	14.93
NY-NJ-PA	62,093	21,455	3,467	87,015	0.51	12.78		0.09	1.56	14.93
VA-MD	62,093	21,455	3,467	87,015	0.51	12.78		0.09	1.56	14.93

2020 Refinery Energy and Emissions Forecast

Estimation of refinery emissions in 2020 are based on a recent study by API.[15] The API study estimated total emissions for oil refining including non-combustion emissions. The API study did not provide a detailed breakdown of combustion energy but included non-combustion emissions associated with hydrogen production, sulfur recovery, and flaring. **Table** 13 summarizes the 2020 base case GHG emissions estimates for oil refining. The table also shows the associated estimates for refinery throughput by PADD. These unit emissions were first defined on a unit basis (lb CO_2e/MMBtu) by the PADD supply regions shown and then allocated on a demand basis according to the inter-PADD movements of refined products previously shown in **Table 7.**

Table 14 shows the unit emissions for refining by demand region.

The GHG estimates for refinery combustion are 5.6 percent higher than the API estimate to account for the added fuel consumption required to produce low sulfur specification heating oil. It is estimated that desulfurization by hydrotreating is equal to 0.8 percent of the fuel value.[16] This amount is equivalent to a 5.6 percent increase in energy consumption and emissions.

The API study focused on total GHG emissions. The associated energy consumption was not reported directly. Therefore, for this analysis, the energy use was assumed to be in the same ratio as the 2006 unit energy to unit emissions.

[15] API, op cit.
[16] Dr. Ray Albrecht, NYSERDA, Private Communication, 4/7/2008.

Table 13 API Estimate of Refinery GHG Emissions by PADD for 2020

Refinery Emissions 2020 (Million Metric Tons CO_2e)	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	U.S. Total
Primary Units						
From H2 Plant	1.2	5.57	16.57	0.4	7.1	30.84
From Refinery Fuel Oil	26.79	52.94	126.03	9.08	48.52	263.36
From Flare/Loss	0.94	2.31	4.89	0.33	1.78	10.25
From Sulfur Plant Tail Gas	0.05	0.15	0.49	0.01	0.16	0.86
Total	28.98	60.97	147.98	9.82	57.56	305.31
Refinery Throughput, trillion Btu	4,124	7,570	19,575	1,423	4,865	37,556

Table 14 2020 GHG Emissions for Refining by PADD Demand Region

Process Units	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Primary Units					
From H2 Plant	0.83	1.62	1.48	1.14	3.22
From Refinery Fuel Oil	14.53	15.32	14.47	14.67	21.99
From Flare/Loss	0.54	0.66	0.55	0.55	0.81
From Sulfur Plant Tail Gas	0.03	0.04	0.05	0.03	0.07
Total	15.93	17.65	16.54	16.39	26.08

2020 Refinery Energy and Emissions Summary by Demand Center

Table 15 summarizes the combustion and non-combustion emissions for the refinery sector by the five demand centers using the same allocation approach described for 2006.

Table 15 2020 Refining Energy Use and GHG Emissions by Demand Center

2020 Refining	Oil Product Use	Other Energy Use	Electric Use	Total Energy Use	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	Btu/MMBtu				lb CO_2e/MMBtu					
OR- WA	63,067	22,086	4,103	89,256	1.31	13.60		0.09	1.72	16.72
Upper Midwest	65,471	19,368	4,644	89,484	1.66	14.26		0.10	1.95	17.97
New England	63,093	21,800	3,523	88,417	0.86	13.35		0.09	1.48	15.78
NY-NJ-PA	63,093	21,800	3,523	88,417	0.86	13.35		0.09	1.48	15.78
VA-MD	63,093	21,800	3,523	88,417	0.86	13.35		0.09	1.48	15.78

Oil Transport and Storage

There are several transportation steps in bringing oil products from the ground to the final consumer. The transportation steps that are considered in this section are as follows:

- Transportation of imported and Alaskan Oil
- Shipments of crude and refined products between PADDs
- Bulk shipment of refined products from refinery centers to distribution centers

- Final retail shipment of home heating oil from distribution terminals to the customer's home.

Transportation of Imported and Alaskan Oil

More than half of the oil used in the U.S. is imported. In addition, oil is shipped by tanker from Alaska to the lower 48-states. The energy and emissions associated with moving this oil is determined by the quantity of oil supplied from each source, the distance traveled, and the energy required and type of energy used per ton-mile to move oil by each mode of transportation. **Table 16** shows the quantity of oil brought into the lower 48-states by PADD in tons.

Table 16 2006 Imports and Oil from Alaska (Thousand tons)

Petroleum Supply Source (1,000 tons)	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Totals
Canada	30,603	63,441	1,747	15,606	6,499	117,897
Mexico	2,007	127.6372	84,580	0	0	86,715
Ocean Imports	162,310	25,774	283,476	13	0	471,574
Alaska	0	0	0	0	46,705	46,705
Lower 48 Production	1,229	23,926	151,551	18,354	0	195,060
Total	196,150	113,270	521,353	33,974	53,204	917,950

Source: EIA Online Petroleum Navigator, units converted to tons

The average mileage traveled for oil from each source is shown in **Table 17**. The mileages are estimated from the gas fuel cycle analysis (Canada, Mexico, Lower 48) and from GREET (Alaska and ocean imports.) The table also shows (by color) the two modes of transport assumed – pipeline for oil coming into the Southern U.S. from Mexico and into the Northern U.S. from Canada. Other oil imports and oil from Alaska come into the U.S. in ocean tankers. Shipments from Mexico to the Northeast and Midwest are assumed to be by tanker or barge. Shipments from Canada to the Gulf are assumed to be by tanker.

Table 17 Estimated Shipment Distance (Miles

Shipment Distance by Supply Source (miles)	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Canada	1,949	1,452	3,000	1,000	500
Mexico	3,000	2,200	750		750
Ocean Imports	5,500	5,500	5,500	5,500	5,500
Alaska					3,900
Lower 48 Production	1,600	1,232	500	500	500

Color Code: Pipeline shipments, Ocean tanker or barge

The assumed unit energy consumption requirements (based on GREET[17]) are as follows:

- Pipeline – 253 Btu/ton-mile (diesel oil)
- Oil Tanker – 42 Btu/ton-mile (residual oil.)

[17] GREET 1.8a, Argonne.

Table 18 and **Table 19** show the calculated energy use and GHG emissions associated with transporting imported and Alaskan oil into each PADD.

Table 18 2006 Energy Requirements for Transporting Oil into the Lower-48-States by PADD

Transport Energy Required (billion Btu)	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Totals
Canada	15,066	23,269	220	3,942	821	43,318
Mexico	253	12	16,024	0	0	16,288
Ocean Imports	37,494	5,954	65,483	3	0	108,934
Alaska	0	0	0	0	7,650	7,650
Lower 48 Production	497	7,446	19,141	2,318	0	29,402
Total	53,310	36,680	100,868	6,263	8,471	205,592
Btu/MMBtu	6,938	8,267	4,939	4,707	4,065	5,718

Table 19 Transport GHG Emissions for Imported and Alaskan Oil (Million lbs CO_2e)

Transport Emissions (Million lb CO_2e)	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Totals
Canada	2,429	3,751	39	635	132	6,986
Mexico	44	2	2,583	0	0	2,629
Ocean Imports	6,576	1,044	11,484	1	0	19,105
Alaska	0	0	0	0	1,342	1,342
Lower 48 Production	80	1,200	3,085	374	0	4,739
Total	9,129	5,997	17,191	1,010	1,474	34,800
CO_2e lbs/MMBtu throughput	1.19	1.35	0.84	0.76	0.71	0.97

Bulk Shipments within the U.S.

Refined products are also shipped between PADDs. The quantity of these inter-PADD shipments is shown in **Table 20**. The assumed product shipment distances are shown in **Table 21**. The assumed distances are based on a rough estimate of distances between major refinery centers and the PADD demand regions. The shipment of refined oil products within each PADD to the five demand centers is included later as part of retail transportation. The share of these shipments that are made by pipeline are shown in **Table 22;** the remaining share of shipments are by barge.

Table 20 2006 Refinery Production and Destination PADDs

2006 Production and Shipments/Use by PADD	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.
	Thousand Tons					
Total Production	92,456	169,718	438,863	31,895	109,069	842,001
Shipments/Use by PADD						
PADD 1	74,428	1,914	131,405			207,747
PADD 2	18,017	156,295	54,161	3,111		231,584
PADD 3	10	10,147	246,532	7,204		263,893
PADD 4		1,362	1,978	19,820		23,160
PADD 5			4,787	1,761	109,069	115,617

Source: EIA Petroleum Navigator was the source of inter-PADD shipments of refinery output. The difference between shipments and total output was assumed to be used within the refining PADD shown in gray.

Table 21 Inter-PADD Shipment Distances (Miles)

Mileage Assumptions for Inter-PADD Shipments	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
PADD 1	0	900	1,200		
PADD 2	400	0	1,200	1,000	
PADD 3	500	750	0	1,500	
PADD 4		750	1,200	0	
PADD 5			1,800	750	0

Table 22 Share of Inter-PADD Shipments by Pipeline

Pipeline Share of Shipments	Receiving PADD				
	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
PADD 1		50.5%	78.7%		
PADD 2	98.3%		94.3%	100.0%	
PADD 3	75.5%	85.3%		100.0%	0.0%
PADD 4		100.0%	100.0%		
PADD 5	0.0%		77.0%	100.0%	

Source: EIA, difference between pipeline shipments and 100% are barge shipments

The unit energy required for these shipments are 253 Btu/ton-mile (diesel oil) for pipeline shipments, as previously stated, and 710 Btu/ton-mile for barge shipments using residual oil. All of these unit energy estimates are based on GREET. The total energy and unit energy requirements are shown in **Table 23**. The GHG emissions are shown in **Table 24**. The energy and emissions intensities by demand region are shown in the final column of each table.

Table 23 2006 GHG Energy Requirements Associated with Inter-PADD Oil Shipments

2006 Production and Shipments/Use by PADD	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.	Energy Use
	Billion Btu						Btu/MMBtu
Shipments/Use by PADD							
PADD 1	0	825	55,214	0	0	56,039	6,887
PADD 2	1,877	0	18,107	786	0	20,770	2,290
PADD 3	2	2,434	0	2,729	0	5,166	500
PADD 4	0	258	600	0	0	858	945
PADD 5	0	0	3,083	334	0	3,417	754
Total U.S.	1,879	3,518	77,003	3,849	0	86,249	

Table 24 2006 GHG Emissions Associated with Inter-PADD Oil Shipments

2006 Production and Shipments/Use by PADD	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total U.S.	Unit GHG by Demand Region
	Million lbs CO_2						lb/MMBtu
Total Production Shipments/Use by PADD						0	
PADD 1	0	142	9,239	0	0	9,380	1.15
PADD 2	304	0	2,956	127	0	3,386	0.37
PADD 3	0	404	0	440	0	844	0.08
PADD 4	0	42	97	0	0	138	0.15
PADD 5	0	0	517	54	0	571	0.13
Total U.S.	304	587	12,808	620	0	14,320	

Table 25 shows a summary of the bulk oil shipments including both primary shipments of imports and oil from Alaska and inter-PADD shipments of refined oil products. The total energy required for bulk shipments is fairly small, ranging from 0.5 percent to 1.4 percent of the energy contained in the delivered product.

Table 25 Summary of Bulk Oil Shipment Unit Energy and GHG Emissions for 2006

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Btu/MMBtu					
Import/Alaska Shipments	7,197	8,025	5,938	5,071	4,065
InterPADD Shipments	6,887	2,290	500	945	754
Total Bulk Shipments	14,084	10,314	6,438	6,016	4,819
lbs CO_2/MMBtu					
Import/Alaska Shipments	1.22	1.31	1.01	0.83	0.71
InterPADD Shipments	1.15	0.37	0.08	0.15	0.13
Total Bulk Shipments	2.37	1.69	1.09	0.98	0.83

Retail Delivery of Heating Oil

The final transport steps consist of the bulk transport of refined oil products from the refineries to the retail distribution terminal. From there the oil is loaded into retail delivery trucks and delivered to the final customers. **Table 26** shows the assumptions, energy, and emissions for these final transport steps for the five retail demand centers defined for this study. Refineries are distributed throughout each PADD. It was assumed for this analysis, that the home heating oil used by each retail demand center comes from a specific refinery/storage area. For the Northwest, the oil is assumed to come from the five refineries located in Washington state near the Canadian border. For the upper Midwest, the refineries are assumed to be located near Chicago. For New England and NY-NJ-PA, the source of the oil is assumed to be the refineries in New Jersey. The oil for Virginia-Maryland is assumed to come from the refineries Southeast of Philadelphia.

Table 26 2006 Summary of Retail and Upstream Transport Energy and Emissions[18]

	OR- WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
Demand Region	PADD 5	PADD 2	PADD 1	PADD 1	PADD 1
Refinery Center	WA	IL	NJ	NJ	PA
Miles to Demand Center	272	47	280	70	135
Btu/MMBtu	1,884	326	1,939	485	935
CO_2/MMBtu	0.304	0.052	0.313	0.078	0.151
Upstream Movements	4,819	10,314	14,084	10,314	6,438
Retail Delivery	3,333	3,333	3,333	3,333	3,333
lb CO_2/MMBtu	0.537	0.537	0.537	0.537	0.537

Energy required for these product shipments is based on the assumption of pipeline transport. The upstream summary comes from previous calculations. Retail delivery energy and emissions estimated from energy use data provided by the National Oilheat Research Alliance showing a range of retail fuel delivery energy consumption of between 150 and 426 gallons of fuel delivered per gallon of fuel used. For this analysis, it was assumed that the retail fuel delivered to diesel fuel used ratio was 300:1.

Retail delivery is the largest component of transport energy use and emissions, but, in total, transport and storage is still a very minor source of energy use and GHG emissions in the heating oil fuel cycle.

Summary of 2006 Transportation Related Energy Use and Emissions

Table 27 summarizes the transportation related energy use and emissions from crude production and imports to the final consumer. Crude transportation and inter-PADD shipments are defined at the PADD level and applied to the five demand centers based on the PADD in which each demand

[18] For calculations purposes the energy required for these product shipments is based on pipeline transport. It is recognized that certain inter-PADDs shipments include a mix of pipeline, ship and barge, however the difference was deemed not significant

center is located. Shipments from the refining center to the demand centers, described in the retail transportation section above, are included with the bulk transportation values, not with the retail transportation which does not vary by region. All of the emissions are combustion related except for a small amount of methane emissions during crude transport and storage.

Table 27 Summary of 2006 Transportation Related Energy Use and Emissions

2006 All Transportation	Oil Product Use	Other Energy Use	Electric Use	Total Energy Use	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	Btu/Mmbtu				lb CO_2e/MMBtu					
Crude Transportation and Storage										
OR- WA	4,819			4,819		0.83	0.02	0.01		0.86
Upper Midwest	10,314			10,314		1.69	0.04	0.01		1.74
New England	14,084			14,084		2.37	0.06	0.02		2.45
NY-NJ-PA	10,314			10,314		2.37	0.06	0.02		2.45
VA-MD	6,438			6,438		2.37	0.06	0.02		2.45
Bulk Shipments from Refinery										
OR- WA	1,884			1,884		0.30		0.00		0.31
Upper Midwest	326			326		0.05		0.00		0.05
New England	1,939			1,939		0.31		0.00		0.31
NY-NJ-PA	485			485		0.08		0.00		0.08
VA-MD	935			935		0.15		0.00		0.15
Retail Delivery										
All Regions	3,333			3,333		0.54		0.00		0.54

2020 Transport Energy and GHG Emissions Forecast

The 2020 estimation of energy used and GHG emissions for transport and storage is nearly the same as for 2006, but the primary shipments of oil imports and oil from Alaska are rebalanced based on estimates of their future share in total U.S. oil use. Domestic production is estimated from the API study. Imports come from the 2020 forecast in EIA's 2007 Annual Energy Outlook. The PADD allocation is based on the 2006 shares. These oil shares are shown in **Table 28.**

Table 28 2020 Oil Shipments from Imports and Alaska (Thousand Tons)

Petroleum Supply Source (thousand tons)	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Totals
Canada	26,581	55,104	1,517	13,555	5,645	102,404
Mexico	3,835	243.8401	161,583	0	0	165,661
Ocean Imports	192,491	54,259	291,787	7,368	0	545,905
Alaska	0	0	0	0	20,537	20,537
Lower 48 Production	1,539	20,003	141,677	17,952	0	181,171
Total	224,446	129,610	596,565	38,875	26,183	1,015,679

All other assumptions described in the development of energy and emissions factors for transport and storage in 2006 remain the same. The resulting energy and emissions factors are shown in **Table 29**.

Table 29 2020 Summary of Retail and Upstream Transport Energy and Emissions

	New England	NY-NJ-PA	VA-MD	Upper Midwest	OR- WA
Demand Center	PADD 1	PADD 1	PADD 1	PADD 2	PADD 5
Refinery Center	NJ	NJ	PA	IL	WA
Miles to Demand Center	280	70	135	47	272
Btu/MMBtu	1,939	485	935	326	1,884
CO_2/MMBtu	0.313	0.078	0.151	0.052	0.304
Upstream Movements	13,755	9,774	6,302	9,774	4,730
Retail Delivery	3,333	3,333	3,333	3,333	3,333
lb CO_2/MMBtu	0.537	0.537	0.537	0.537	0.537

The differences between 2006 and 2020 transport energy and emissions are relatively minor.

Summary of 2020 Transportation Related Energy Use and Emissions by Demand Center

Table 30 summarizes the transportation related emissions by demand center for 2020. The allocation and approach are the same as previously described for 2006.

Table 30 Summary of Transportation Related Energy Use and Emissions for 2020

2006 All Transportation	Oil Product Use	Other Energy Use	Electric Use	Total Energy Use	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	Btu/MMbtu				lb CO_2e/MMBtu					
Crude Transportation and Storage										
OR- WA	4,730			4,730		0.81	0.02	0.01		0.84
Upper Midwest	9,774			9,774		1.62	0.04	0.01		1.67
New England	13,755			13,755		2.33	0.06	0.02		2.40
NY-NJ-PA	9,774			9,774		2.33	0.06	0.02		2.40
VA-MD	6,302			6,302		2.33	0.06	0.02		2.40
Bulk Shipments from Refinery										
OR- WA	1,884			1,884		0.30		0.00		0.31
Upper Midwest	326			326		0.05		0.00		0.05
New England	1,939			1,939		0.31		0.00		0.31
NY-NJ-PA	485			485		0.08		0.00		0.08
VA-MD	935			935		0.15		0.00		0.15
Retail Delivery										
All Regions	3,333			3,333		0.54		0.00		0.54

Heating Oil Total Fuel Cycle Energy Use and GHG Emissions

The overall estimates of the total resource energy consumption and GHG emissions related to supplying home heating oil to each of the five market areas are summarized in this section. The GHG emissions by process step are shown in **Table 31** and graphically in **Figure 2** and **Figure 3**. Combustion of heating oil by the final consumer produces 161.19 pounds of CO_2e per million Btu. As shown, the fuel cycle emissions add another 17.5 to 18.3 percent to the GHG emissions from combustion. In 2020, fuel cycle emissions increase to 19.0 to 20.1 percent of the final combustion emissions. This increase is primarily due to the additional refinery energy needed to produce the low sulfur specification fuel oil. **Table 31** also shows that the total fuel cycle efficiency of supplying heating oil to each of the five market demand regions ranges between 85.6 and 86.1 percent in 2006 and between 85.3 and 86.1 percent in 2020.

Table 31 Summary of Oil Fuel Cycle GHG Emissions for 2006 and 2020

Fuel Cycle Stage	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
2006 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)					
Exploration and Production	11.33	11.33	11.33	11.33	11.33
Transportation and Storage	0.86	1.74	2.45	2.45	2.45
Refining	15.10	15.84	14.93	14.93	14.93
Bulk Shipments from Refinery	0.31	0.05	0.31	0.08	0.15
Retail Delivery	0.54	0.54	0.54	0.54	0.54
Final Combustion	161.19	161.19	161.19	161.19	161.19
Total Fuel Cycle Emissions	189.32	190.70	190.75	190.52	190.59
Total Fuel Cycle Efficiency	86.5%	85.9%	85.6%	86.1%	86.5%
2020 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)					
Exploration and Production	12.17	12.17	12.17	12.17	12.17
Transportation and Storage	0.84	1.67	2.40	2.40	2.40
Refining	16.72	17.97	15.78	15.78	15.78
Bulk Shipments from Refinery	0.31	0.05	0.31	0.08	0.15
Retail Delivery	0.54	0.54	0.54	0.54	0.54
Final Combustion	161.19	161.19	161.19	161.19	161.19
Total Fuel Cycle Emissions	191.77	193.59	192.40	192.16	192.24
Total Fuel Cycle Efficiency	86.1%	85.7%	85.3%	85.8%	86.1%

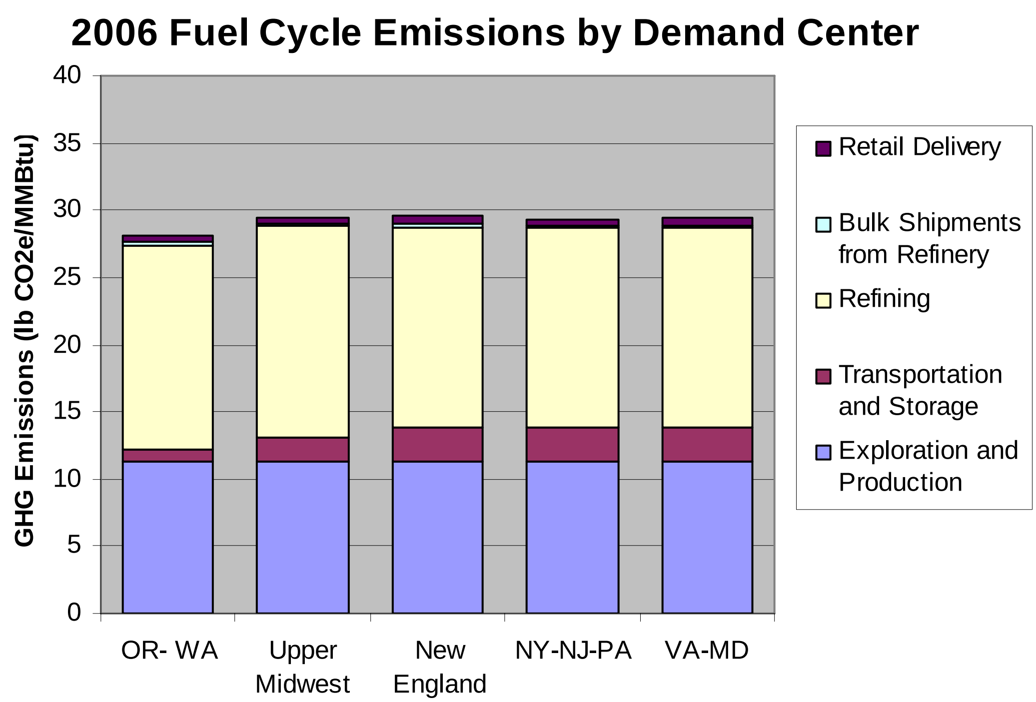


Figure 2 2006 GHG Emissions for Oil Fuel Cycle by Demand Region

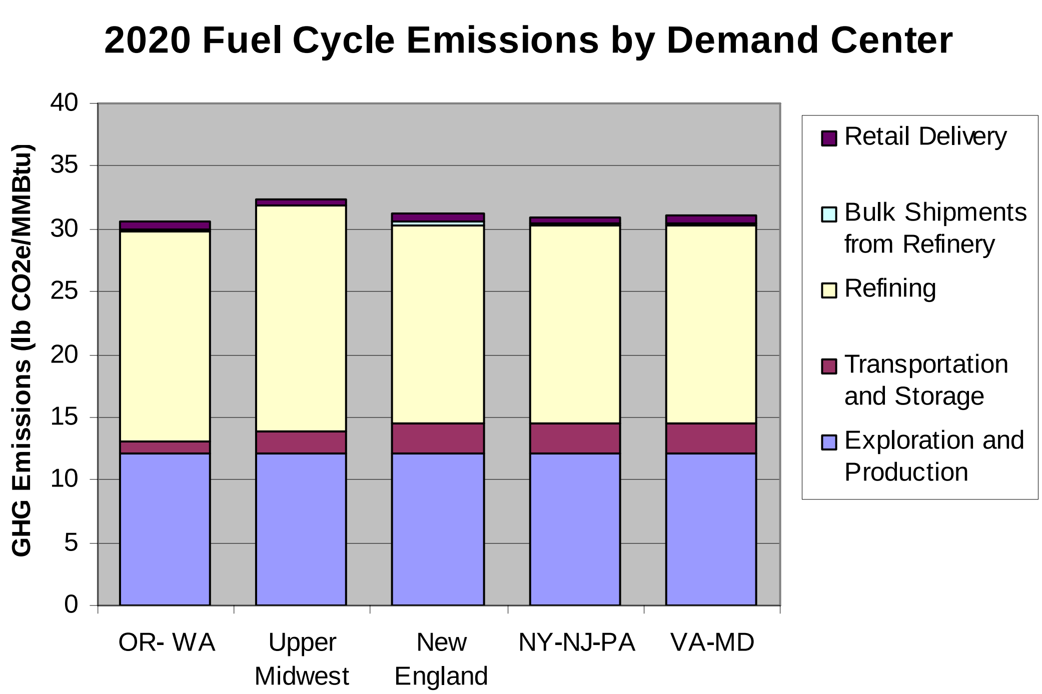


Figure 3 2020 GHG Emissions for Oil Fuel Cycle by Demand Region

Table 32 and **Table 33** summarize the energy use and emissions by industry fuel cycle segment for the five demand regions in 2006. **Table 34** and **Table 35** show the results for 2020. The energy use is split into three categories as follows:

- Oil Product Use – all of the oil products used in the fuel cycle stage
- Other Energy Use – all other sources of energy except for electricity
- Electricity Use – the quantity of electricity used on a delivered energy value basis.

The emissions are categorized into five categories as follows:

- Non-combustion CO_2 – represents emissions from processes other than combustion, specifically CO_2 emitted from oil well production and CO_2 from hydrogen production in refineries.
- Combustion CO_2 – represents all combustion related emissions from energy use at each stage except for indirect emissions
- CH_4 Emissions – the GWP associated with emissions of methane converted to CO_2 equivalence at a rate of 23:1.
- N_2O Emissions – the GWP associated with emissions of nitrous oxide converted to CO_2 equivalence at a rate of 296:1.
- Indirect Emissions – off-site emissions related to electricity and steam consumption.

Table 32 2006 Fuel Cycle Energy Use for the Five Demand Regions

2006 Fuel Cycle Efficiency	Oil Product Use	Other Energy Use	Electric Use	Total Energy Use
	Btu/MMBtu			
Washington/Oregon				
Exploration and Production	3,901	29,435	3,872	37,208
Transportation and Storage	4,819			4,819
Refining	62,193	21,787	4,044	88,023
Bulk Shipments from Refinery	1,884			1,884
Retail Delivery	3,333			3,333
Total	*76,130*	*51,222*	*7,916*	*135,267*
Upper Midwest				
Exploration and Production	3,901	29,435	3,872	37,208
Transportation and Storage	10,314			10,314
Refining	66,112	19,558	4,690	90,359
Bulk Shipments from Refinery	326			326
Retail Delivery	3,333			3,333
Total	*83,986*	*48,993*	*8,562*	*141,541*
New England				
Exploration and Production	3,901	29,435	3,872	37,208
Transportation and Storage	14,084			14,084
Refining	62,093	21,455	3,467	87,015
Bulk Shipments from Refinery	1,939			1,939
Retail Delivery	3,333			3,333
Total	*85,350*	*50,890*	*7,339*	*143,579*
New York/New Jersey/Pennsylvania				
Exploration and Production	3,901	29,435	3,872	37,208
Transportation and Storage	10,314			10,314
Refining	62,093	21,455	3,467	87,015
Bulk Shipments from Refinery	485			485
Retail Delivery	3,333			3,333
Total	*80,126*	*50,890*	*7,339*	*138,355*
Virginia/Maryland				
Exploration and Production	3,901	29,435	3,872	37,208
Transportation and Storage	6,438			6,438
Refining	62,093	21,455	3,467	87,015
Bulk Shipments from Refinery	935			935
Retail Delivery	3,333			3,333
Total	*76,700*	*50,890*	*7,339*	*134,929*

Table 33 2006 Fuel Cycle GHG Emissions for the Five Demand Regions

2006 Fuel GHG Emissions	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	lb CO_2e/MMBtu					
Washington/Oregon						
Exploration and Production	0.00	4.07	5.59	0.04	1.62	11.33
Transportation and Storage		0.83	0.02	0.01		0.86
Refining	0.51	12.62		0.09	1.88	15.10
Bulk Shipments from Refinery		0.30		0.00		0.31
Retail Delivery		0.54		0.00		0.54
Total	*0.51*	*18.37*	*5.61*	*0.14*	*3.51*	*28.13*
Upper Midwest						
Exploration and Production	0.00	4.07	5.59	0.04	1.62	11.33
Transportation and Storage		1.69	0.04	0.01		1.74
Refining	0.64	12.98		0.09	2.14	15.84
Bulk Shipments from Refinery		0.05		0.00		0.05
Retail Delivery		0.54		0.00		0.54
Total	*0.64*	*19.33*	*5.63*	*0.14*	*3.76*	*29.51*
New England						
Exploration and Production	0.00	4.07	5.59	0.04	1.62	11.33
Transportation and Storage		2.37	0.06	0.02		2.45
Refining	0.51	12.62		0.09	1.72	14.93
Bulk Shipments from Refinery		0.31		0.00		0.31
Retail Delivery		0.54		0.00		0.54
Total	*0.51*	*19.91*	*5.65*	*0.15*	*3.34*	*29.56*
New York/New Jersey/Pennsylvania						
Exploration and Production	0.00	4.07	5.59	0.04	1.62	11.33
Transportation and Storage		2.37	0.06	0.02	0	2.45
Refining	0.51	12.62	0	0.09	1.72	14.93
Bulk Shipments from Refinery		0.08		0.00		0.08
Retail Delivery		0.54		0.00		0.54
Total	*0.51*	*19.68*	*5.65*	*0.15*	*3.34*	*29.33*
Virginia/Maryland						
Exploration and Production	0.00	4.07	5.59	0.04	1.62	11.33
Transportation and Storage		2.37	0.06	0.02	0.00	2.45
Refining	0.51	12.62	0	0.09	1.72	14.93
Bulk Shipments from Refinery		0.15		0.00		0.15
Retail Delivery		0.54		0.00		0.54
Total	*0.51*	*19.75*	*5.65*	*0.15*	*3.34*	*29.40*

Table 34 2020 Fuel Cycle Energy Use for the Five Demand Regions

2020 Fuel Cycle Efficiency	Oil Product Use	Other Energy Use	Electric Use	Total Energy Use
	Btu/MMBtu			
Washington/Oregon				
Exploration and Production	4,191	31,626	4,160	39,978
Transportation and Storage	4,730			4,730
Refining	63,067	22,086	4,103	89,256
Bulk Shipments from Refinery	1,884			1,884
Retail Delivery	3,333			3,333
Total	*77,205*	*53,712*	*8,263*	*139,180*
Upper Midwest				
Exploration and Production	4,191	31,626	4,160	39,978
Transportation and Storage	9,774			9,774
Refining	65,471	19,368	4,644	89,484
Bulk Shipments from Refinery	326			326
Retail Delivery	3,333			3,333
Total	*83,095*	*50,994*	*8,804*	*142,894*
New England				
Exploration and Production	4,191	31,626	4,160	39,978
Transportation and Storage	13,755			13,755
Refining	63,093	21,800	3,523	88,417
Bulk Shipments from Refinery	1,939			1,939
Retail Delivery	3,333			3,333
Total	*86,312*	*53,427*	*7,683*	*147,422*
New York/New Jersey/Pennsylvania				
Exploration and Production	4,191	31,626	4,160	39,978
Transportation and Storage	9,774			9,774
Refining	63,093	21,800	3,523	88,417
Bulk Shipments from Refinery	485			485
Retail Delivery	3,333			3,333
Total	*80,876*	*53,427*	*7,683*	*141,986*
Virginia/Maryland				
Exploration and Production	4,191	31,626	4,160	39,978
Transportation and Storage	6,302			6,302
Refining	63,093	21,800	3,523	88,417
Bulk Shipments from Refinery	935			935
Retail Delivery	3,333			3,333
Total	*77,854*	*53,427*	*7,683*	*138,964*

Table 35 2020 Fuel Cycle GHG Emissions for the Five Demand Regions

2020 Fuel Cycle Efficiency	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	lb CO_2e/MMBtu					
Washington/Oregon						
Exploration and Production	0.00	4.38	6.00	0.04	1.75	12.17
Transportation and Storage		0.81	0.02	0.01		0.84
Refining	1.31	13.60		0.09	1.72	16.72
Bulk Shipments from Refinery		0.30		0.00		0.31
Retail Delivery		0.54		0.00		0.54
Total	*1.31*	*19.63*	*6.02*	*0.15*	*3.47*	*30.58*
Upper Midwest						
Exploration and Production	0.00	4.38	6.00	0.04	1.75	12.17
Transportation and Storage		1.62	0.04	0.01		1.67
Refining	1.66	14.26		0.10	1.95	17.97
Bulk Shipments from Refinery		0.05		0.00		0.05
Retail Delivery		0.54		0.00		0.54
Total	*1.66*	*20.84*	*6.04*	*0.16*	*3.70*	*32.40*
New England						
Exploration and Production	0.00	4.38	6.00	0.04	1.75	12.17
Transportation and Storage		2.33	0.06	0.02		2.40
Refining	0.86	13.35		0.09	1.48	15.78
Bulk Shipments from Refinery		0.31		0.00		0.31
Retail Delivery		0.54		0.00		0.54
Total	*0.86*	*20.90*	*6.06*	*0.16*	*3.22*	*31.21*
New York/New Jersey/Pennsylvania						
Exploration and Production	0.00	4.38	6.00	0.04	1.75	12.17
Transportation and Storage		2.33	0.06	0.02		2.40
Refining	0.86	13.35		0.09	1.48	15.78
Bulk Shipments from Refinery		0.08		0.00		0.08
Retail Delivery		0.54		0.00		0.54
Total	*0.86*	*20.67*	*6.06*	*0.15*	*3.22*	*30.97*
Virginia/Maryland						
Exploration and Production	0.00	4.38	6.00	0.04	1.75	12.17
Transportation and Storage		2.33	0.06	0.02		2.40
Refining	0.86	13.35		0.09	1.48	15.78
Bulk Shipments from Refinery		0.15		0.00		0.15
Retail Delivery		0.54		0.00		0.54
Total	*0.86*	*20.74*	*6.06*	*0.16*	*3.22*	*31.04*

3
NATURAL GAS FUEL CYCLE ANALYSIS

Introduction

This section describes the results and analytical approach of a full fuel cycle analysis of the energy used and GHG emissions associated with supplying natural gas to five designated demand regions throughout the United States.

Natural gas is a commodity that is produced and consumed at many different locations throughout North America. The extensive natural gas pipeline network in North America connects regional gas markets and allows supplies to move to the retail demand markets. The vast majority of the gas consumed in the residential and commercial sectors is gas purchased from gas utilities, often referred to as local distribution companies (LDCs). Utilities buy gas from producers, rely on pipeline capacity to transport the gas to their distribution system, and use their system to move the gas to residents and commercial establishments. About 1,000 different gas utilities buy and resell gas to residential and commercial gas customers throughout the U.S.

North American natural gas supply is diverse, with gas originating from many different sources and areas. Historically, North America has been self reliant, and most of its gas supply has come from the U.S. Gulf Coast producing area and from the Western Canadian Sedimentary Basin. Recently, both areas have shown signs of resource depletion, shifting the focus of gas producers to different formations (generally deeper sediments) and to other areas. For example, there has been increased focus on developing gas resource located in the deeper waters of the Gulf of Mexico[19], with less emphasis on developing shallow water gas resource where most historical activity has been concentrated. LNG imports are also high on the list of potential new gas supplies for the North American gas market. In short, gas suppliers are looking to new frontiers for future supplies.

North American gas consumption is predicted to continue to grow for the foreseeable future. Many new sources of supply are geographically far removed from the ultimate markets that they will serve, which presents many challenges. ICF expects that a significant market will develop for global LNG trade over the next two decades. Imported LNG, in large part, becomes an economically viable energy supply because of the low cost of developing and producing abundant and sometimes stranded gas reserves located throughout the world. Many analysts expect that U.S. LNG imports will grow significantly in the future. To do so, full use of the existing import capacity will occur and a number of new import terminals will be required.

To transport natural gas supplies to market, North America has an extensive integrated network of pipelines. The system consists of over 200,000 miles of interstate pipelines in the U.S. and 60,000

[19] Activity has shifted out to water depths greater than 200 meters.

miles of interprovincial pipelines in Canada. Figure 4 shows the natural gas pipeline flows within North America.

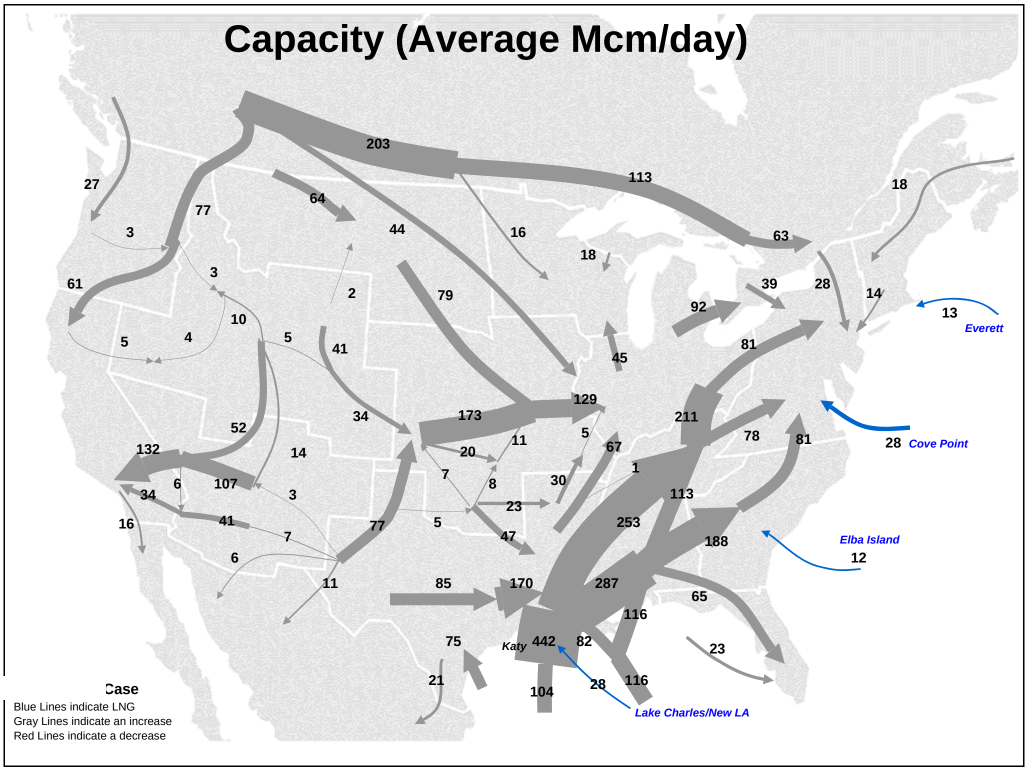


Figure 4 Natural Gas Interregional Pipeline Capacities, 2004 (ICF)

Analytical Framework

The natural gas that is delivered to final customers in the United States is the product of a complex series of interrelated activities, which each require energy and emit greenhouse gases (GHG). This section describes the natural gas fuel cycle analysis, and the quantification of the energy and emissions of all of the activities that are required to deliver a unit of natural gas to the ultimate customer.

The North American natural gas (NANG) supply chain consists of six sectors:

- **Exploration and drilling -** Natural gas reserves are discovered through geological surveys and developed into new production through the drilling of exploratory wells. Major GHG emissions sources associated with exploration and drilling include diesel combustion in drilling rigs and natural gas venting and flaring during gas well completion.

- **Production -** Natural gas is produced from associated gas wells that produce both oil and gas, non-associated gas wells that produce gas only, and unconventional wells such as coal-bed methane wells. GHG emissions from natural gas production are driven by the amount of gas produced, the type of wells producing the gas, and the age and upkeep of producing wells.

- **Processing -** Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. GHG emissions from natural gas processing include direct emissions such as combustion, fugitive and vented/flared methane and indirect emissions from imported electrical power.

- **Transmission -** The transmission system for natural gas consists of a complex network of pipelines, designed to quickly and efficiently transport natural gas from its origin, to areas of high demand. Emissions from the transport of natural gas in North America occur chiefly from compressor exhaust at compressor stations located along natural gas pipelines.

- **Distribution -** Distribution is the final step in delivering natural gas to end users. Most users receive natural gas from a local distribution company (LDC) that transports natural gas from delivery points along interstate and intrastate pipelines through thousands of miles of small-diameter distribution pipe. GHG emissions in the distribution network are primarily caused by leaks in distribution pipes.

Imported liquefied natural gas (LNG) shares the same six sectors as NANG with the addition of three extra steps:

- **Liquefaction and loading –** In order to transport natural gas from other continents the gas can be cooled and liquefied. LNG is very useful for transporting natural gas in tankers since it takes up about one six hundredth the volume of gaseous natural gas.

- **Shipping** - LNG is transported in specialized cryogenic tankers that keep the LNG insulated to minimize boil-off during the voyage. LNG tankers can be fueled in a number of ways: boil-off fired steam plants, dual fired boil-off gas and diesel, and diesel only with boil-off gas reliquefaction.

- **Regasification and storage** - Regasification of LNG is the process of warming up LNG and returning it to the properties of regular natural gas. Regasification requires around 1.5 percent of the gas send-out as fuel for the process.

This chapter will separately address each of the fuel cycle stages. The NANG fuel cycle stages that vary based on the supply region (exploration, production, and processing) will be discussed separately from the LNG fuel cycle stages that also vary based on the supply region (exploration, production, processing, liquefaction, shipping, and regasification). The fuel cycle stages that vary based on the demand region (transmission and distribution) will be discussed for all natural gas (NANG and LNG) that is consumed in each region. Estimates of energy use and emissions during the natural gas fuel cycle are made for five home heating market areas:

- Oregon-Washington (Pacific Northwest)
- Upper Midwest, such as Milwaukee.
- New England
- New York, Pennsylvania, New Jersey
- Virginia-Maryland

Each of the five demand regions evaluated in this study receive natural gas from a specific combination of supply regions. **Table 36** shows the amount of natural gas used in each demand region by the supply region it comes from. This data was taken from the ICF International GMM model and reflects the actual supply share for 2006 and a forecasted supply share for 2020 based on NANG supply trends and increased dependence on imported LNG. The variations in supply mix impact the full fuel cycle energy use and GHG emissions attributable to natural gas in each home heating market area as different supply sources have varying energy use and GHG emissions characteristics based on differences in production, processing and transportation.

Table 36 Natural Gas Supply Shares by Demand Region for 2006 and 2020

Demand and Supply **Regions**	**2006**		**2020**	
	Supply Share	Gas Transported (Bcf)	Supply Share	Gas Transported (Bcf)
Oregon & Washington				
Western Canada	84.0%	265.47	81.0%	324.23
Rocky Mountains	16.0%	50.57	19.0%	76.05
Total Supply	*100%*	*316.04*	*100%*	*400.29*
Upper Midwest				
Western Canada	59.0%	580.95	55.8%	639.77
Rocky Mountains	8.5%	83.70	9.2%	105.98
MidContinent	25.5%	251.09	13.9%	158.96
Gulf Coast	7.0%	68.93	21.1%	242.52
Total Supply	*100%*	*984.66*	*100%*	*1147.24*
New England				
Eastern Canada	5.5%	44.43	12.4%	101.29
Western Canada	39.2%	313.68	12.4%	101.29
Gulf Coast	33.4%	267.34	21.4%	173.96
LNG - New England	20.6%	165.12	36.8%	299.61
LNG - Canada Maritimes	1.3%	10.15	17.0%	138.46
Total Supply	*100%*	*800.72*	*100%*	*814.60*
New York/New Jersey/Pennsylvania				
Western Canada	19.5%	159.25	7.0%	62.92
Rocky Mountains	1.7%	13.85	7.3%	65.57
Southwest	27.2%	221.64	31.8%	284.12
MidContinent	5.1%	41.56	9.8%	87.42
Gulf Coast	41.8%	340.43	15.7%	140.05
East Coast LNG	2.9%	23.80	6.8%	60.68
Gulf Coast LNG	1.8%	14.28	21.6%	193.62
Total Supply	*100%*	*814.81*	*100%*	*894.39*
Virginia & Maryland				
Rocky Mountains	0.5%	1.34	1.8%	7.04
Southwest	7.5%	21.40	7.9%	30.52
MidContinent	1.4%	4.01	2.4%	9.39
Gulf Coast	75.8%	217.22	41.4%	160.47
East Coast LNG	13.7%	39.16	39.0%	150.83
Gulf Coast LNG	1.1%	3.26	7.5%	28.91
Total Supply	*100%*	*286.40*	*100%*	*387.16*

North American Natural Gas (NANG)

The current state of the North American natural gas industry is well defined in data from the US Energy Information Administration (EIA). Existing greenhouse gas emissions from the natural gas industry are also estimated in the EPA's *Inventory of US Greenhouse Gas Emissions and Sink: 1990 – 2005*. The estimates of emissions intensity for NANG in 2006 provided in this report build upon these resources and reflect the current state of the industry in terms of energy use and emissions. As in the oil analysis, GHG emissions in the natural gas cycle were into three broad categories: vented, fugitive, and combustion emissions, using the framework established by API. Again:

- Combustion emissions are the emissions associated with the combustion of fuel for engines, turbines, heaters, steam production, and gas flaring. Combustion emissions may be for either energy use or non-energy use, such as flaring.
- Vented emissions are the designed and intentional equipment vents to the atmosphere. Venting occurs from oil tanks, pneumatic devices, pumps, equipment blowdown, well completions, well workovers, and other processes.
- Fugitive emissions are unintentional equipment leaks. These leaks occur at the wellhead, from separators, heaters, crude headers, floating CO_2 roof tanks, and compressors.

It should be noted that the term "unaccounted-for gas" is often a source of confusion in understanding the operation of the natural gas supply system and in estimating methane emissions. The term, "unaccounted-for gas," does not always indicate a leak. Unaccounted for gas is the difference between the amount of gas purchased and the quantity of gas sold, with leakage being only one of a number of contributing factors. The Office of Pipeline Safety in the Department of Transportation lists 17 or more conditions that contribute to unaccounted-for gas, including a variety of gas measurement issues. Other than limited fugitive emissions from valve packing, pinholes, intentional blowdowns and instrument leaks, most unaccounted for gas is caused by limitations of flow measurement accuracies due to temperature and pressure effects, poor operation and maintenance practices and suboptimum application.

Emissions projections to 2020 are subject to many factors including changing natural gas prices and greenhouse gas emissions legislation which are outside the scope of this study. The energy use and emissions intensity estimates for 2020 are based primarily on industry trends identified in EIA's Annual Energy Outlook and from ICF's internal projection of natural gas supply and industry trends. Adjustments to the emissions profile of the US gas industry have also been made based on changing technology. Results from the EPA Natural Gas STAR program were used to develop assumptions for the rate of GHG emissions reductions (primarily methane) that would take place between 2006 and 2020. The EPA Natural Gas STAR program is a voluntary partnership program between the EPA and oil and gas companies that promotes the implementation of cost-effective technologies to mitigate methane emissions from the industry. The partners report their savings of methane emissions from their operations on an annual basis to the program. The program then reports these emission reductions on a yearly basis. The Natural Gas STAR Partners do not represent the entire natural gas production or processing industry, so adjustments to the Partner-reported reductions were made to represent entire industry based on a projection of technology implementation. The Natural Gas STAR program estimates that methane emissions from the U.S. natural gas industry have been reduced by 577 Bcf since the program's inception with 78 Bcf of reductions in 2006. Methane emissions were projected to be reduced an additional 25 percent by 2020 for this analysis. It should be noted that the actual level of reductions will be influenced by energy costs and greenhouse gas emissions legislation, and could be as high as 50 percent with aggressive implementation of best available practices and technologies.

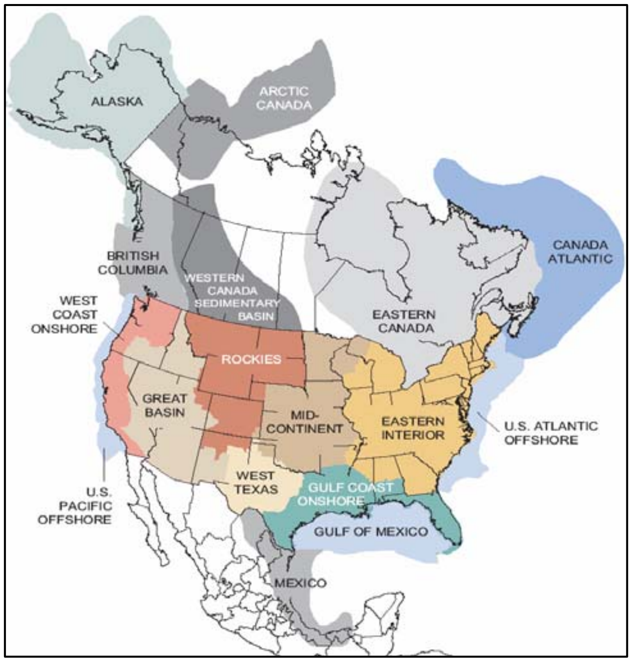
The energy use and emissions for the three major GHGs were estimated for each stage in an internal ICF model that uses emission factors and activity factors from various reference data sources. The activity factors were adjusted for the base year 2006 by using activity drivers (e.g., number of wells drilled in a production area, miles of coated steel distribution pipe). The activity drivers serve as model inputs such that any changes in the activity drivers, such as number of wells, are reflected throughout the model in terms of the final emissions estimates. In essence, the activity drivers (or model inputs) drive the emissions estimates.

Exploration and Drilling

Natural gas reserves are discovered through geological surveys and developed into new production through the drilling of exploratory wells. New wells that are drilled into a producing formation are completed and tied into gas sales pipelines. Major GHG emissions sources associated with exploration and drilling include diesel combustion in drilling rigs and natural gas venting and flaring during gas well completion. Driving factors that can have an effect on the magnitude of GHG emissions include average well depth, type of well (oil with associated gas or non-associated gas) and the fraction of gas wells requiring hydraulic fractures to stimulate production. In the United States many new wells are drilled in unconventional formations that often require hydraulic fractures as part of the well completion process before they can produce gas for sales. Wells requiring hydraulic fracture may vent large volumes of natural gas as water, sand, and gas are flown back during well completion. Countries exporting natural gas to the United States generally produce gas from conventional formations that do not require hydraulic fractures and result in much smaller well completion emissions.

NANG drilling and wells in 2006 and 2020 were estimated using the ICF Hydrocarbon Supply Model (HSM). In 2006, it was estimated that over 35,000 exploratory and developmental wells were drilled in the United States; this number is projected to decrease to only 20,000 wells drilled in 2020. All emissions associated with natural gas well drilling in the United States are accounted for in the NANG scenario. The North American gas resource regions are shown in **Figure 5.** The regions shown are the aggregate regions (so called Super Regions) used in the 2003 National Petroleum Council (NPC) study[20] of the natural gas industry.

[20] National Petroleum Council, Natural Gas Policy: Fueling the Demands of a Growing Economy, 2003



Source: U.S. National Petroleum Council

Figure 5: North American Production Areas

In the exploration and drilling stage, the primary energy use is diesel fuel consumed by drilling rigs to drill new exploratory oil and gas wells. **Table 37** and **Table 38** show the energy intensity of the exploration and drilling stage for each supply region in 2006 and 2020. There is a large variance in the amount of fuel used between regions, with the MidContinent region using four times the amount of fuel as the Gulf Coast and Eastern Canada regions. Several factors affect the energy intensity of regional drilling operations including average well depth, number of wells drilled, and total productivity of wells in the region. Gulf Coast wells were assumed to be drilled to an average depth of 10,500 feet requiring a large amount of fuel per well, but the average production rate of Gulf Coast wells is several times higher than MidContinent wells meaning the energy input per Btu of gas produced in the Gulf Coast is lower.

Table 37 NANG 2006 Energy Intensity of Natural Gas Exploration and Drilling by Supply Region

Supply Regions	Fuel Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Western Canada	1,603	0	1,603
Rocky Mountains	1,603	0	1,603
Southwest	2,180	0	2,180
MidContinent	4,830	0	4,830
Gulf Coast	1,226	0	1,226
Eastern Canada	1,226	0	1,226

Table 38 NANG 2020 Energy Intensity of Natural Gas Exploration and Drilling by Supply Region

Supply Regions	Fuel Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Western Canada	1,087	0	1,087
Rocky Mountains	1,087	0	1,087
Southwest	1,008	0	1,008
MidContinent	2,887	0	2,887
Gulf Coast	1,243	0	1,243
Eastern Canada	1,243	0	1,243

Table 39 and **Table 40** show the GHG emissions intensity of the exploration and drilling process for each of the NANG supply regions for 2006 and 2020. The emissions due to combustion CO_2, N_2O, and indirect CO_2 all come from the energy use during the drilling stage, whereas the non-combustion CO_2 and CH_4 (methane) emissions come from gas venting and leaks.

Table 39 2006 NANG GHG Emissions Intensity of Exploration and Drilling by Supply Regions

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Western Canada	0.00122	0.263	0.099	0.000	0.000	0.363
Rocky Mountains	0.00122	0.263	0.099	0.000	0.000	0.363
Southwest	0.00063	0.357	0.105	0.000	0.000	0.463
MidContinent	0.00009	0.792	0.068	0.000	0.000	0.860
Gulf Coast	0.00010	0.201	0.029	0.000	0.000	0.230
Eastern Canada	0.00010	0.201	0.029	0.000	0.000	0.230

Table 40 2020 NANG GHG Emissions Intensity of Exploration and Drilling by Supply Regions

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Western Canada	0.00232	0.178	0.188	0.000	0.000	0.368
Rocky Mountains	0.00232	0.178	0.188	0.000	0.000	0.368
Southwest	0.00050	0.165	0.082	0.000	0.000	0.248
MidContinent	0.00015	0.473	0.116	0.000	0.000	0.590
Gulf Coast	0.00017	0.204	0.048	0.000	0.000	0.252
Eastern Canada	0.00017	0.204	0.048	0.000	0.000	0.252

Production

Natural gas is produced from associated gas wells that produce both oil and gas, non-associated gas wells that produce gas only, and unconventional wells such as coal-bed methane wells. Major GHG emissions sources associated with natural gas production include CO_2 emissions from lease fuel consumption in compressors and natural gas flaring, as well as CH_4 emissions from compressor fugitives and gas vented during well clean-ups. GHG emissions from natural gas production are driven by the amount of gas produced, the type of wells producing the gas, and the age and upkeep of producing wells. GHG emissions estimates from these sources were based on specific activity drivers, and activity emissions factors. The activity emissions factors are based on initial estimates by EPA and GRI, updated by ICF estimates developed in supporting the annual EPA Greenhouse Emissions Inventory and the recent API study of oil and gas industry emissions. After the gas is produced from the well it must be delivered to gas processing facilities. Greenhouse gas emissions from gathering and boosting compressors were calculated based on the amount of horsepower required to deliver the gas through gathering pipelines to the processing and the fuel used by the compressors.

NANG is produced through a mix of associated, non-associated, and unconventional wells; the average natural gas production rate from individual wells in the US is only around 30 million cubic feet per year whereas natural gas wells from countries exporting LNG can have production rates that are much higher. The larger number of wells needed to produce the same amount of gas in the US requires more equipment and consequently will have more energy use associated with production. **Table 41** and **Table 42** show the energy intensity of NANG production by supply region for 2006 and 2020.

Table 41 NANG 2006 Energy Intensity of Natural Gas Production by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Western Canada	26,005	4,974	30,980
Rocky Mountains	26,005	4,974	30,980
Southwest	26,278	8,558	54,101
MidContinent	26,228	2,064	12,884
Gulf Coast	19,962	4,652	24,614
Eastern Canada	19,962	4,652	24,614

Table 42 NANG 2020 Energy Intensity of Natural Gas Production by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Western Canada	29,915	4,983	34,898
Rocky Mountains	29,915	4,983	34,898
Southwest	16,715	5,002	36,224
MidContinent	25,331	1,655	11,744
Gulf Coast	23,498	4,505	28,003
Eastern Canada	23,498	4,505	28,003

Emissions from the Natural Gas Production Sector

Methane Emissions

The primary basis for estimates of methane emissions from the natural gas production sector is the API *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (API 2004) with an additional resource being a study by EPA (EPA/GRI 1996). In several cases, ICF estimated emission factors from raw data provided in the EPA/GRI study or used other sources to provide for emission factors more accurate than those provided in either the API or EPA/GRI reports. Emission factors for natural gas well unloading were updated from the EPA/GRI factors based on data reported by Natural Gas STAR Partners in the *Installing Plunger Lift Systems in Gas Wells* Lessons Learned document. The emissions factors for well venting and flaring during gas well completion and gas well workovers were also adjusted based on data reported by Natural Gas STAR Partners that were presented at a Technology Transfer workshop in Houston on September 21, 2004. The EPA/GRI emission factor for small reciprocating compressor fugitives was determined to have errors during the initial measurement and calculations and was replaced by scaling reciprocating compressor fugitives in the transmission sector down to production sector levels using gas throughput.

The natural gas production model uses the following activity drivers as inputs to project future emissions in 2020 since equipment counts for each source are not available for the year 2006. The natural gas production model inputs are as follows:

- Total national volume of dry natural gas production
- Total volume of Alaska natural gas production
- Total volume of water production in the Powder River Basin
- Total count of wells in the Black Warrior Basin
- Total count of natural gas wells drilled in the U.S.
- Total volume of natural gas vented and flared onshore
- Associated, non-associated, and unconventional natural gas well counts
- Total count of Gulf of Mexico shallow and deepwater natural gas production platforms
- Total volume of natural gas vented and flared from offshore natural gas production operations
- Total volume of Lease condensate production

Carbon Dioxide and Nitrous Oxide Emissions

Fugitive and vented CO_2 emissions were estimated for all sources that have CH_4 emissions, except offshore platforms. The CO_2 emissions were estimated using the same activity factors as those used for estimating CH_4 emissions. The CH_4 emission factors were adjusted for the CO_2 content in natural gas to estimate CO_2 emission factors using the following formula:

$$\text{CO}_2 \text{ Emission Factor} = \frac{\text{CH}_4 \text{ Emission Factor * CO}_2 \text{ Content in Natural Gas}}{\text{CH}_4 \text{ Content in Natural Gas}}$$

These CO_2 emission factors were used in conjunction with the activity factors to estimate CO_2 emissions. GRI's *Unconventional Natural Gas and Gas Composition Databases* were used to estimate the CO_2 content in produced natural gas.

Combustion CO_2 emissions were estimated from four sources on a nation-wide level: offshore deep water platforms, offshore shallow water platforms, lease fuel[21] combustion, and electricity consumption. Combustion N_2O emissions were estimated from three sources on a nation-wide level: offshore deep water platforms, offshore shallow water platforms, and lease fuel.

The MMS study[22] (GOADS 2000) provides estimates of vented and combusted CO_2 and N_2O emissions from each offshore platform in the Gulf of Mexico. This database was used to estimate CO_2 and N_2O emissions from offshore natural gas platforms with the emission factor being emission per platform and activity factor being the number of gas platforms (gas platform defined as one located on a predominantly gas producing field as identified by MMS).

The national lease fuel consumption was obtained from the Energy Information Administration and used as an activity factor to estimate the amount of energy related CO_2 and N_2O emissions from the combustion of natural gas in heaters, engine, compressors, and other combustion equipment used in oil and natural gas production[23]. CO_2 emissions were estimated using a lease fuel activity factor from EIA and emission factor from the API Compendium (API 2004). N_2O emissions from lease fuel combustion are assumed to be primarily from internal combustion engines. Therefore, N_2O emissions were estimated based on an emissions factor for four-cycle lean burn internal combustion engines (API 2004) consuming lease fuel for natural gas production.

Electricity is occasionally used in producing fields that have access to a power grid. CO_2 (and CH_4) emissions for oil and gas production[24] were estimated for onshore electricity consumption using electricity imports activity data from U.S. Census Bureau and an emission factor from the API Compendium. Energy use for electricity consumption was based on a heat rate 0f 10,3000 Btu/kWh.

The large number of wells needed to produce gas in the US requires more equipment than other countries and consequently will have more fugitive and venting emissions. 2006 GHG emissions intensity from US production ranged from 20.03 lb CO_2e/MMBtu to 8.73 lb CO_2e/MMBtu depending on the region. The primary difference for the GHG emissions intensity between regions is the methane content of the natural gas.

Table 43 and **Table 44** show the emissions intensity for natural gas production by supply region in 2006 and 2020. The emissions due to combustion CO_2, N_2O, and indirect CO_2 all come from the energy use during the stage, whereas the non-combustion CO_2 and CH_4 (methane) emissions come from gas venting and leaks. The difference in methane emissions between regions is primarily due to differences in the methane content of the gas. 2020 emissions reflect energy use projections and activity driver projections for each area based on production trends.

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21 Lease fuel is defined by EIA as "natural gas used in well, field, and lease operations, such as gas used in drilling operations, heaters, dehydrators, and field compressors."

22 Minerals Management Service (2004). Gulfwide Emission Inventory Study for the Regional Haze and Ozone Modeling Effort, OCS Study MMS 2004-072.

23 Note that lease fuel information provided by EIA is for both oil and natural gas production.

24 Note that electricity consumption information provided by the U.S. Census Bureau's Crude Petroleum and Natural Gas Extraction: 2002 – 2002 Economic Census is for both oil and natural gas production.

Table 43 NANG 2006 GHG Emissions Intensity of Natural Gas Production by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Western Canada	0.13	3.47	9.09	0.02	1.95	14.65
Rocky Mountains	0.13	3.47	9.09	0.02	1.95	14.65
Southwest	0.08	3.52	9.83	0.04	1.95	15.42
MidContinent	0.04	3.52	14.52	0.01	1.93	20.03
Gulf Coast	0.01	3.35	3.53	0.02	1.82	8.73
Eastern Canada	0.01	3.35	3.53	0.02	1.82	8.73

Table 44 NANG 2020 GHG Emissions Intensity of Natural Gas Production by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Western Canada	0.25	3.99	13.73	0.02	1.95	19.94
Rocky Mountains	0.25	3.99	13.73	0.02	1.95	19.94
Southwest	0.07	2.24	6.01	0.02	1.06	9.40
MidContinent	0.05	3.40	12.70	0.01	1.59	17.76
Gulf Coast	0.02	3.81	3.79	0.02	1.76	9.41
Eastern Canada	0.02	3.81	3.79	0.02	1.76	9.41

Processing

Natural gas processing plants purify the raw natural gas that is recovered from gas wells during the production process. Raw natural gas consists primarily of methane, however it also contains other heavier gaseous hydrocarbons, acid gases (carbon dioxide, hydrogen sulfide), other gases (nitrogen, helium), water vapor, and liquid hydrocarbons. This raw gas must be processed into almost pure methane in order to meet the standards of natural gas pipeline and distribution companies. Energy is used in the natural gas processing stage to compress the gas and remove water, H_2S, CO_2, and fractionate liquids. Only the energy required to process natural gas to pipeline quality is included in this analysis; energy used to fractionate out different liquid products is not considered part of the natural gas supply chain, but is part of the liquids product chains. **Table 45** and **Table 46** show the energy intensity of NANG processing by supply region for 2006 and 2020. 2006 energy use in the Southwest region is much higher than the other regions reflecting differences in raw gas composition and processing requirements. This data comes from natural gas processing plant fuel consumption information published by EIA for each state. Changes in 2020 reflect estimates on changing raw gas composition and processing trends.

Table 45 NANG 2006 Energy Intensity of Natural Gas Processing by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Western Canada	15,639	1,483	17,122
Rocky Mountains	15,639	1,483	17,122
Southwest	36,540	6,862	43,402
MidContinent	20,643	6,633	27,276
Gulf Coast	13,770	2,175	15,946
Eastern Canada	13,770	2,175	15,946

Table 46 NANG 2020 Energy Intensity of Natural Gas Processing by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Western Canada	21,045	2,133	23,178
Rocky Mountains	21,045	2,133	23,178
Southwest	22,949	4,603	27,552
MidContinent	17,042	5,848	22,890
Gulf Coast	16,186	2,723	18,909
Eastern Canada	16,186	2,723	18,909

Major GHG emissions sources associated with natural gas processing include CO_2 emissions from plant fuel combustion in compressors and venting from acid gas removal units, as well as CH_4 fugitives from compressors. The specific carbon-dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions for the natural gas processing sector were estimated using the ICF Gas Processing GHG Model for the base year 2006, and projected forward to 2020. The model calculates source specific CO_2, CH_4, and N_2O emissions from individual gas processing facilities in the United States. The configuration of each plant was estimated from details in the Worldwide Processing Survey from the Oil and Gas Journal. Both direct (combustion, fugitive and vented/flared) and indirect (imported electrical power) emissions are estimated for each U.S. processing plant.

GHG emissions intensity from gas processing ranged from 4.46 to 10.60 lb CO2e/MMBtu for NANG in 2006. Most regions are projected to have increased emissions intensity in 2020. The increase in LNG delivered to the US during this timeframe will require additional processing facilities leading to additional emissions. **Table 47** and **Table 48** show the GHG emissions intensity for the supply regions. The emissions due to combustion CO_2, N_2O, and indirect CO_2 all come from the energy use during the fuel stage, whereas the non-combustion CO_2 and CH_4 (methane) emissions come from gas venting and leaks.

Table 47 NANG 2006 Emissions Intensity of Natural Gas Processing by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Western Canada	0.82	2.10	0.95	0.02	0.58	4.46
Rocky Mountains	0.82	2.10	0.95	0.02	0.58	4.46
Southwest	1.97	4.15	1.75	0.03	2.69	10.6
MidContinent	1.02	3.18	1.55	0.03	2.60	8.37
Gulf Coast	1.01	1.91	1.02	0.02	0.85	4.81
Eastern Canada	1.01	1.91	1.02	0.02	0.85	4.81

Table 48 NANG 2020 Emissions Intensity of Natural Gas Processing by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Western Canada	1.81	2.83	0.96	0.02	0.84	6.46
Rocky Mountains	1.81	2.83	0.96	0.02	0.84	6.46
Southwest	1.32	2.61	0.83	0.02	1.80	6.58
MidContinent	0.90	2.62	0.97	0.02	2.29	6.81
Gulf Coast	1.42	2.24	0.91	0.02	1.07	5.65
Eastern Canada	1.42	2.24	0.91	0.02	1.07	5.65

Emissions from the Natural Gas Processing Sector

Methane Emissions

The primary source of emission factors for estimating methane emissions from the U.S. natural gas processing sector is the API *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* with an additional resource being the study by the Gas Research Institute and EPA (EPA/GRI 1996).

The natural gas processing model uses the following activity drivers as inputs to estimate greenhouse gas emissions:

- Total national count of natural gas processing plants
- Total national amount of natural gas processed
- Total national amount of dry natural gas production
- Amount of Alaska natural gas production

Carbon Dioxide and Nitrous Oxide Emissions

Fugitive and vented CO_2 emissions were estimated for all sources that have CH_4 emissions. Two additional CO_2 emission sources were needed to account for compressor fugitive emissions of CO_2 before and after the acid gas removal unit. The CO_2 emissions were estimated using the same activity factors as those used for estimating CH_4 emissions. The CH_4 emission factors were adjusted for CO_2 content in natural gas to estimate CO_2 emission factors using the following formula:

$$CO_2 \ \text{Emission Factor} = \frac{CH_4 \ \text{Emission Factor} * CO_2 \ \text{Content in Natural Gas}}{CH_4 \ \text{Content in Natural Gas}}$$

These CO_2 emission factors were used in conjunction with the activity factors to estimate CO_2 emissions.

In a processing plant, CO_2 is removed from natural gas in Acid Gas Removal (AGR) units at a particular point in the various gas processing stages. Therefore, CO_2 emissions occur from two gas streams; one stream that has production level CO_2 in natural gas before the extraction stage in the AGR unit and the other stream which has transmission level CO_2 in natural gas after the AGR unit stage. The allocation of emission sources to the two streams was done using data from measurements at four gas processing plants by Clearstone Engineering (2002). For example, the total number of compressors in processing plants was allocated to the two streams based on the proportion of compressors in each of the two streams in the Clearstone study. The GRI *Unconventional Natural Gas and Gas Composition Databases* were used to estimate CO_2 content in produced natural gas. The transmission level CO_2 in natural gas was available from EIA (1994).

Energy related CO_2 emissions for this sector were derived from information from EIA on natural gas consumption as Plant fuel[25], which was used as the activity factor in determining the greenhouse gas emissions. The model assumed 100 percent combustion efficiency when converting the natural gas to CO_2 emissions.

Electricity use for each processing plant was estimated using the information in the Oil & Gas Journal *Worldwide Gas Processing Survey* (OGJ Survey) along with rules and assumptions made about the electricity required to run a processing plant. Electricity was assumed to be consumed by pumps and for refrigeration for each plant. For example, all reflux pumps on the fractionation units were assumed to have a reflux rate at 10 percent of the feed; the pressure drop across reflux pump is 30 pounds per square inch; and the electrical efficiency is 80 percent.

Liquefied Natural Gas (LNG)

The United States currently has five active LNG import terminals along the East and Gulf coasts. The EIA tracks LNG imports delivered to these terminals, but does not have data on the activities upstream of the import terminals in the countries of origin. Downstream of the import terminals, LNG is regasified and enters the US transmission and distribution systems as any other supply of natural gas. Natural gas losses through fugitives, venting, and consumption upstream of the LNG import terminal were estimated to back calculate the amount of natural gas that must be produced in each foreign country to satisfy demand in the US. Countries importing LNG to the US in 2006 include Algeria, Egypt, Nigeria, and Trinidad & Tobago. As demand for LNG increases, additional import terminals will be constructed along the US coasts. The Federal Energy Regulatory Commission (FERC) tracks existing and proposed LNG terminals; there are currently 21 new LNG terminals approved by FERC and many more proposed terminals. **Figure 6** shows the locations of proposed import terminals in North America.

[25] Lease fuel is defined by EIA as “natural gas used as fuel in natural gas processing plants.”

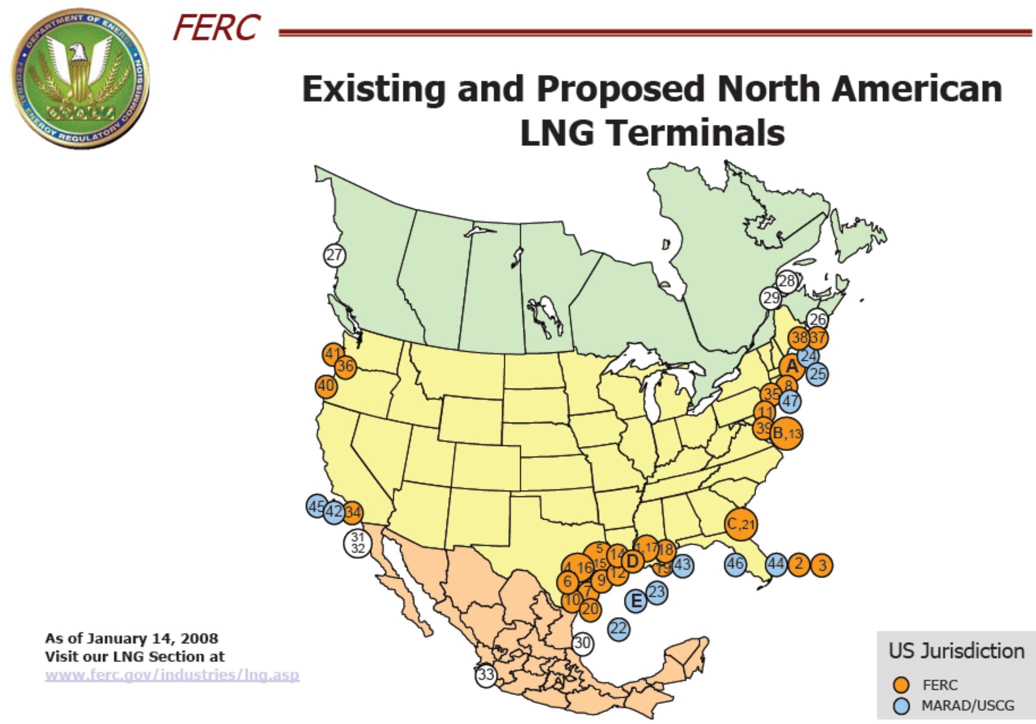

Figure 6: Existing and Proposed North American LNG Import Terminals

New points of origin will also come online as LNG export terminals are constructed worldwide in areas of abundant gas supply. The projection of LNG imports in 2020 in this study assumes LNG will be delivered from Algeria, Angola, Australia, Egypt, Equatorial Guinea, Indonesia, Nigeria, Norway, Oman, Qatar, Trinidad & Tobago, and Yemen. **Table 49** shows the amount of LNG that is imported into the US in 2006 (actual) and 2020 (projected) by the country of origin. **Table 50** breaks down the percent of LNG that each terminal is receiving from the countries of origin in 2006, whereas **Table 51** shows the same breakdown for 2020. Finally, **Table 52** shows the volume of LNG imports into each US terminal.

Table 49 LNG Imports into the US by Country of Origin for 2006 and 2020

Country of Origin	2006 Volume Imported into US (MMcf as Gas)	2006 %	2020 Volume Imported into US (MMcf as Gas)	2020 %
Algeria	17,449	2.9%	447,318	11.0%
Angola	0	0.0%	103,642	2.5%
Australia	0	0.0%	318,802	7.8%
Egypt	119,528	19.9%	311,174	7.6%
Equatorial Guinea	0	0.0%	70,476	1.7%
Indonesia	0	0.0%	173,289	4.3%
Nigeria	62,715	10.4%	692,742	17.0%
Norway	0	0.0%	87,059	2.1%
Oman	0	0.0%	38,140	0.9%
Qatar	5,998	1.0%	802,685	19.7%
Saudi Arabia	0	0.0%	452,707	11.1%
Trinidad & Tobago	394,614	65.7%	465,559	11.4%
Yemen	0	0.0%	112,762	2.8%
Total	600,303	100.0%	4,076,355	100.0%

Table 50 Percent of LNG Imports from Country of Origin to LNG Terminal (2006)

	East Coast LNG		New England LNG	Gulf Coast LNG		Canadian Maritimes LNG
Country of Origin	**Cove Point, MD**	**Elba Island, GA**	**Everett, MA**	**Gulf Gateway, LA**	**Lake Charles, LA**	**Canada**
Algeria	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Angola	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Australia	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Egypt	12.5%	28.9%	0.0%	0.0%	43.6%	0.0%
Equatorial Guinea	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Indonesia	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nigeria	0.0%	0.0%	0.0%	31.4%	39.9%	0.0%
Norway	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oman	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Qatar	0.0%	0.0%	0.0%	34.8%	0.0%	0.0%
Saudi Arabia	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Trinidad & Tobago	72.5%	71.1%	100.0%	33.8%	16.5%	100.0%
Yemen	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 51 Percent of LNG Imports from Country of Origin to LNG Terminal (2020)

	East Coast LNG			New England LNG	Gulf Coast LNG			Canadian Maritimes LNG
Country of Origin	**Cove Point, MD**	**Elba Island, GA**	**New East Coast**	**Everett, MA**	**Gulf Gateway, LA**	**Lake Charles, LA**	**New Gulf Coast**	**Canada**
Algeria	29.1%	0.0%	30.7%	0.0%	0.0%	28.0%	5.2%	0.0%
Angola	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.1%	0.0%
Australia	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Egypt	14.1%	19.6%	0.0%	0.0%	0.0%	15.0%	5.0%	0.0%
Equatorial Guinea	0.0%	8.6%	0.0%	0.0%	0.0%	6.6%	0.0%	0.0%
Indonesia	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.6%	0.0%
Nigeria	14.5%	13.6%	11.2%	0.0%	47.9%	30.7%	18.3%	0.0%
Norway	25.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oman	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.0%
Qatar	0.0%	39.4%	0.0%	0.0%	0.0%	0.0%	31.7%	0.0%
Saudi Arabia	0.0%	0.0%	0.0%	0.0%	0.0%	14.5%	18.6%	0.0%
Trinidad & Tobago	16.9%	18.8%	52.5%	100.0%	24.4%	5.3%	1.5%	100.0%
Yemen	0.0%	0.0%	5.6%	0.0%	27.7%	0.0%	4.2%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 52 LNG Imports by Volume and Import Terminal for 2006 and 2020

	2006		**2020**	
Import Terminal	Volume Imported into US (MMcf as Gas)	%	Volume Imported into US (MMcf as Gas)	%
Everett, MA	176,097	29.3%	103,426	2.5%
Cove Point, MD	116,613	19.4%	343,543	8.4%
Elba Island, GA	146,766	24.4%	410,488	10.1%
New East Coast	0	0.0%	302,145	7.4%
Lake Charles, LA	143,568	23.9%	536,566	13.2%
Gulf Gateway, LA	17,259	2.9%	40,677	1.0%
New Gulf Coast	0	0.0%	2,020,708	49.6%
New West Coast	0	0.0%	318,802	7.8%
Total	600,303	100.0%	4,076,355	100.0%

Exploration and Drilling

In the LNG imports scenario, only wells drilled (oil and gas) for the purposes of producing gas to meet the demand requirements of the United States are counted in the supply chain emissions. Emissions from exploration and drilling are small and account for less than 1 percent of supply chain emissions (excluding gas consumption) in both the NANG and imported LNG scenarios. **Table 53** and **Table 54** show the energy intensity of exploration and drilling for each of the LNG supply regions. There is a small difference in the energy used between the Gulf Coast and other regions; this is due to differences in the countries where the LNG for each region comes from. The New England, Canadian, and East Coast LNG terminals get the majority of their LNG from Trinidad and Tobago along with other nearby countries (this can be seen in Table 50 and Table 51). The Gulf Coast gets LNG primarily from African and Middle Eastern countries. Variations in the process stages of these regions cause differences in the energy use and emissions for each LNG fuel cycle stage.

Table 53 LNG 2006 Energy Intensity of Natural Gas Exploration and Drilling by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	328	0	328
Canadian Maritimes LNG	328	0	328
East Coast LNG	328	0	328
Gulf Coast LNG	316	0	316

Table 54 LNG 2020 Energy Intensity of Natural Gas Exploration and Drilling by Supply Region

Supply Regions	Fuel Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	249	0	249
Canadian Maritimes LNG	249	0	249
East Coast LNG	249	0	249
Gulf Coast LNG	219	0	219

Countries exporting natural gas to the United States generally produce gas from conventional formations that do not require hydraulic fractures and result in much smaller well completion emissions than the unconventional formations found in the US. **Table 55** and **Table 56** show the emissions intensity for foreign natural gas exploration and drilling ventures that will ultimately be made into LNG and shipped to the US. The emissions intensity decreases from 2006 to 2020 because of drilling technology improvements in LNG producing countries. The emissions due to combustion CO_2 come from the energy use during the fuel stage, whereas the non-combustion CO_2 and CH_4 (methane) emissions come from gas venting and leaks.

Table 55 2006 LNG Emission Intensity of Exploration and Drilling of Supply Regions

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	0.000003	0.054	0.002	0.000	0.000	0.056
Canadian Maritimes LNG	0.000003	0.054	0.002	0.000	0.000	0.056
East Coast LNG	0.000003	0.054	0.002	0.000	0.000	0.056
Gulf Coast LNG	0.000003	0.052	0.002	0.000	0.000	0.054

Table 56 2020 LNG Emission Intensity of Exploration and Drilling of Supply Regions

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	0.00000	0.041	0.001	0.000	0.000	0.042
Canadian Maritimes LNG	0.00000	0.041	0.001	0.000	0.000	0.042
East Coast LNG	0.00000	0.041	0.001	0.000	0.000	0.042
Gulf Coast LNG	0.00007	0.036	0.001	0.000	0.000	0.037

Production

Natural gas production in foreign countries is very similar to production of NANG in terms of how energy is used and which processes cause GHG emissions, however natural gas wells from countries exporting LNG can have production rates that are significantly higher than those in the US. The amount of energy used in the production process is fairly similar for the US and foreign countries, however the emissions intensity is lower in foreign countries due to less use of equipment that has fugitive and venting emissions. **Table 57** and **Table 58** show the energy intensity for LNG natural gas production by import supply region for 2006 and 2020. **Table 59** and **Table 60** show the GHG emissions intensity of natural gas production by import supply region for 2006 and 2020. The emissions due to combustion CO_2 come from the energy use during the fuel stage, whereas the non-combustion CO_2 and CH_4 (methane) emissions come from gas venting and leaks.

Table 57 LNG 2006 Energy Intensity of Natural Gas Production by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	22,912	0	22,912
Canadian Maritimes LNG	22,912	0	22,912
East Coast LNG	22,912	0	22,912
Gulf Coast LNG	23,623	0	23,623

Table 58 LNG 2020 Energy Intensity of Natural Gas Production by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
LNG New England	23,506	0	23,506
LNG Canadian Maritimes	23,506	0	23,506
East Coast LNG	23,506	0	23,506
Gulf Coast LNG	31,385	0	31,385

Table 59 LNG 2006 GHG Emissions Intensity of Natural Gas Production by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	0.01	3.08	4.11	0.00	0.00	7.21
Canadian Maritimes LNG	0.01	3.08	4.11	0.00	0.00	7.21
East Coast LNG	0.01	3.08	4.11	0.00	0.00	7.21
Gulf Coast LNG	0.01	3.18	4.36	0.00	0.00	7.55

Table 60 LNG 2020 GHG Emissions Intensity of Natural Gas Production by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	0.02	3.16	3.16	0.00	0.00	6.34
Canadian Maritimes LNG	0.02	3.16	3.16	0.00	0.00	6.34
East Coast LNG	0.02	3.16	3.16	0.00	0.00	6.34
Gulf Coast LNG	0.22	4.22	3.92	0.00	0.00	8.36

Processing

Gas processing energy use and emissions in LNG exporting countries is very similar to those in the US and were estimated from the ICF Gas Processing GHG Model. US plants of similar size and configuration necessary to handle gas produced in foreign countries were selected to model the processing emissions associated with exported LNG. The gas processing plants selected to estimate the GHG emissions were required to include Acid Gas Removal (AGR) units for the removal of CO_2 and hydrogen sulfide (H_2S), and dehydrators with molecular sieves for the extraction of water from the natural gas feed as these impurities will cause difficulties in gas liquefaction downstream of the processing plant. The gas processing plants also required fractionation for the removal of heavy hydrocarbons when the throughput was associated gas whereas, little fractionation was required for non-associated gas throughput. Gas throughput and CO_2 content of the gas were adjusted in the representative plant to match the production characteristics of the producing country. The emissions due to combustion CO_2, N_2O, and indirect CO_2 all come from the energy use during the fuel stage, whereas the non-combustion CO_2 and CH4 (methane) emissions come from gas venting and leaks. **Table 61** and **Table 62** show the energy intensity of natural gas processing for LNG import supply regions for 2006 and 2020.

Table 61 LNG 2006 Energy Intensity of Natural Gas Processing by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	25,886	1,195	27,081
Canadian Maritimes LNG	25,886	1,195	27,081
East Coast LNG	25,886	1,195	27,081
Gulf Coast LNG	26,676	3,209	29,885

Table 62 LNG 2020 Energy Intensity of Natural Gas Processing by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	24,845	7,893	32,738
Canadian Maritimes LNG	24,845	7,893	32,738
East Coast LNG	24,845	7,893	32,738
Gulf Coast LNG	32,449	12,078	44,527

Table 63 and **Table 64** show the GHG emissions intensity associated with each LNG import supply region for 2006 and 2020. The emissions due to combustion CO_2, N_2O, and indirect CO_2 all come from the energy use during the fuel stage, whereas the non-combustion CO_2 and CH_4 (methane) emissions come from gas venting and leaks.

Table 63 LNG 2006 GHG Emissions Intensity of Natural Gas Processing by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	1.44	3.48	0.61	0.03	0.47	6.02
Canadian Maritimes LNG	1.44	3.48	0.61	0.03	0.47	6.02
East Coast LNG	1.44	3.48	0.61	0.03	0.47	6.02
Gulf Coast LNG	2.23	3.59	0.69	0.03	1.26	7.79

Table 64 LNG 2020 GHG Emissions Intensity of Natural Gas Processing by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	3.03	3.34	0.57	0.03	3.09	10.06
Canadian Maritimes LNG	3.03	3.34	0.57	0.03	3.09	10.06
East Coast LNG	3.03	3.34	0.57	0.03	3.09	10.06
Gulf Coast LNG	7.38	4.37	0.76	0.04	4.73	17.28

Liquefaction

A number of factors contribute to the total energy consumption of liquefaction facilities. Natural gas is consumed to fuel the liquefaction process, generate electricity for the plant as well as loading operations, and fuel compressors to collect boil-off gas from the storage tanks. The volume of natural gas consumed by the liquefaction process was estimated based on energy and material balances around the LNG liquefaction process and supporting loading activities. Specifications from the Pluto LNG and Darwin LNG projects in Australia, as well as the ConocoPhillips Optimized Cascade process were utilized to construct a generic LNG liquefaction plant and loading model[26].

The fuel required for the loading activities is dependent on the natural gas consumed by the electric power generators and boil off compressors. Natural gas fired generators are assumed to run the loading pump used to deliver LNG from the storage tanks to the LNG carriers as well as satisfy the base electricity needs of the liquefaction plant. The loading pump horsepower was calculated by assuming the LNG shipping carrier specifications and the loading pipe parameters. LNG carriers were assumed to have an average capacity of 154,000 m^3 of LNG. These generators have a higher fuel requirement during loading operations however they are assumed to be functional throughout the year.

The LNG liquefaction and storage plant was assumed to have boil-off compressors sized to meet not only the daily boil-off rate, as well as an additional compressor to handle gas from the ship vapor return lines during loading activities. The amount of natural gas required to fuel the boil-off compressor is based on the horsepower requirement of the compressor, and is assumed to operate throughout the year. The ship vapor recovery compressor is assumed to have a similar horsepower requirement as the boil-off, operating only during loading. **Table 65** and **Table 66** show the energy intensity of natural gas liquefaction for LNG import supply regions for 2006 and 2020. Natural gas is consumed to fuel the liquefaction process, generate electricity for the plant as well as loading operations, and fuel compressors to collect boil-off gas from the storage tanks. Different configurations of LNG export facilities worldwide will show slight variations in energy consumption over the base energy needed to actually liquefy a unit of natural gas. Variations in the energy use for liquefaction between different regions can be seen in **Table 65**.

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[26] ConocoPhillips. "ConocoPhillips Optimized Cascade Process." March. 2006.
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Table 65 LNG 2006 Energy Intensity of Natural Gas Liquefaction by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	92,423	0	92,423
Canadian Maritimes LNG	92,423	0	92,423
East Coast LNG	92,423	0	92,423
Gulf Coast LNG	88,584	0	88,584

Table 66 LNG 2020 Energy Intensity of Natural Gas Liquefaction by Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	81,465	0	81,465
Canadian Maritimes LNG	81,465	0	81,465
East Coast LNG	81,465	0	81,465
Gulf Coast LNG	83,370	0	83,370

The primary GHG emissions sources associated with liquefaction include CO_2 emissions from fuel combustion to operate the liquefaction process, generate electricity, and operate boil-off compressors. Total natural gas consumption as fuel for liquefaction and loading was estimated to be around 8 percent of the amount of gas liquefied and delivered to the US. This represents an average emissions intensity of 10.8 lb CO_2e/MMBtu for imported LNG in 2006 and 9.8 lb CO_2e/MMBtu in 2020. **Table 67** and **Table 68** show the GHG emissions intensity associated with liquefaction for each LNG import supply region for 2006 and 2020. The emissions due to combustion CO_2, N_2O, and indirect CO_2 all come from the energy use during the fuel stage, whereas the CH_4 (methane) emissions come from gas venting and leaks.

Table 67 LNG 2006 Emissions Intensity of Natural Gas Liquefaction by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	0.00	10.82	0.02	0.09	0.00	10.92
Canadian Maritimes LNG	0.00	10.82	0.02	0.09	0.00	10.92
East Coast LNG	0.00	10.82	0.02	0.09	0.00	10.92
Gulf Coast LNG	0.00	10.37	0.02	0.08	0.00	10.47

Table 68 LNG 2020 Emissions Intensity of Natural Gas Liquefaction by Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
New England LNG	0.00	9.54	0.01	0.08	0.00	9.63
Canadian Maritimes LNG	0.00	9.54	0.01	0.08	0.00	9.63
East Coast LNG	0.00	9.54	0.01	0.08	0.00	9.63
Gulf Coast LNG	0.00	9.76	0.02	0.08	0.00	9.85

Shipping

LNG is transported in specialized cryogenic tankers that keep the LNG insulated to minimize boil-off during the voyage. LNG tankers can be fueled in a number of ways: boil-off fired steam plants, dual fired boil-off gas and diesel, and diesel only with boil-off gas reliquefaction. All LNG shipping was assumed to use a dual fired engine that consumes boil-off gas for 84 percent of its fuel requirements and makes up the rest with diesel. In 2006, the average tanker size was assumed to be 154,000 m^3 while newly constructed tankers were assumed to increase the average fleet size by 2020. Voyage duration was estimated using a service speed of 19.5 knots to cover the approximate distance between the port of origin and destination terminal. LNG losses along the voyage were estimated using a 0.15 percent of cargo capacity per day boil-off rate for the laden voyage. The LNG tanker was assumed to keep a small heel of LNG in its tanks to maintain cryogenic temperatures on the unladen voyage. This heel was estimated to be 200 percent of the boil-off fuel required for the laden voyage. **Table 69** and **Table 70** show the energy intensity of natural gas shipping by the import supply regions for 2006 and 2020. The energy intensity for the Gulf Coast supply region is higher than the other regions because each unit of LNG delivered to the Gulf Coast travels a much longer distance consuming more fuel than an equivalent unit of LNG delivered to the East Coast. Most imports of LNG to the East Coast come from Trinidad and Tobago, whereas imports into the Gulf Coast tend to come from Africa or the Middle East. In 2006, each unit of LNG delivered to the East Coast traveled an average of 2,460 miles while each unit of LNG traveled an average of 5,686 miles to reach the Gulf Coast. The longer distance traveled to reach the Gulf Coast is reflected in the energy consumption shown in the tables.

Table 69 LNG 2006 Energy Intensity of Natural Gas Shipping by Import Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	22,446	0	22,446
Canadian Maritimes LNG	22,446	0	22,446
East Coast LNG	22,446	0	22,446
Gulf Coast LNG	49,822	0	49,822

Table 70 LNG 2020 Energy Intensity of Natural Gas Shipping by Import Supply Region

Supply Regions	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
New England LNG	42,350	0	42,350
Canadian Maritimes LNG	42,350	0	42,350
East Coast LNG	42,350	0	42,350
Gulf Coast LNG	69,201	0	69,201

Average emissions intensity for LNG shipping was estimated as 3.90 lb CO_2e/MMBtu in 2006 and 9.62 lb CO_2e/MMBtu in 2020. **Table 71** and **Table 72** show the GHG emissions intensity for natural gas shipping by import supply region for 2006 and 2020. The only GHG emissions related to this fuel cycle stage have to do with the fuel burned to power the LNG tanker, therefore only combustion CO_2 is shown in the tables. The emissions intensity for the Gulf Coast region is over double that of other regions because it reflects the additional energy consumption associated with shipping LNG over a longer distance.

Table 71 LNG 2006 GHG Emissions Intensity of Natural Gas Shipping by Import Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
LNG New England	0.00	3.00	0.00	0.00	0.00	3.00
LNG Canadian Maritimes	0.00	3.00	0.00	0.00	0.00	3.00
East Coast LNG	0.00	3.00	0.00	0.00	0.00	3.00
Gulf Coast LNG	0.00	6.35	0.00	0.00	0.00	6.35

Table 72 LNG 2020 GHG Emissions Intensity of Natural Gas Shipping by Import Supply Region

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
LNG New England	0.00	6.94	0.00	0.00	0.00	6.94
LNG Canadian Maritimes	0.00	6.94	0.00	0.00	0.00	6.94
East Coast LNG	0.00	6.94	0.00	0.00	0.00	6.94
Gulf Coast LNG	0.00	10.40	0.00	0.00	0.00	10.40

Regasification and Storage

The primary use of energy in LNG regasification and storage is in the vaporization of LNG into natural gas prior to injection into the transmission system. LNG delivered to the US is stored as LNG at the import terminals then pumped up to pipeline pressure and vaporized for injection into the US transmission system. Storage tanks are equipped with boil-off gas compression and all vaporization was assumed to use submerged combustion vaporizers (SCV). Vaporization of LNG requires around 1.5 percent of the gas send-out as fuel for the SCV. **Table 73** shows the energy intensity of natural gas regasification for both 2006 and 2020. This is a standardized process and is uniform throughout the country. It also not expected to change between 2006 and 2020.

Table 73 Energy Intensity of Natural Gas Regasification

Supply Regions	Natural Gas Use Btu/Mmbtu	Electric Use Btu/Mmbtu	Total Energy Use Btu/Mmbtu
LNG New England	14,829	0	14,829
LNG Canadian Maritimes	14,829	0	14,829
East Coast LNG	14,829	0	14,829
Gulf Coast LNG	14,829	0	14,829

Emissions intensity for regasification operations were estimated as 1.75 lb CO_2e/MMBtu in 2006 and are projected to remain the same in 2020. **Table 74** shows the GHG emissions intensity for natural gas regasification for both 2006 and 2020. The emissions due to combustion CO_2, N_2O, and indirect CO_2 all come from the energy use during the fuel stage, whereas the non-combustion CO_2 and CH_4 (methane) emissions come from gas venting and leaks.

Table 74 GHG Emissions Intensity of Natural Gas Regasification

Supply Regions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
LNG New England	0.00	1.74	0.00	0.01	0.00	1.75
LNG Canadian Maritimes	0.00	1.74	0.00	0.01	0.00	1.75
East Coast LNG	0.00	1.74	0.00	0.01	0.00	1.75
Gulf Coast LNG	0.00	1.74	0.00	0.01	0.00	1.75

Transmission and Distribution

The transmission and distribution portions of the natural gas fuel cycle are the same for both NANG and LNG imports because once LNG is regasified and put into the pipeline transmission system it is unidentifiable from NANG. The amount of energy and emissions from transmission and distribution is unique to each demand region, so the tables in this section will be tied to each of the five market regions specified at the beginning of the natural gas section. The transmission energy and emissions are based on the pipeline distance that natural gas must flow through to arrive at the demand regions, while the distribution energy and emissions are a function of the type of distribution pipe networks in each demand regions.

Transmission

Emissions from the transport of natural gas in North America occur chiefly from compressor exhaust at compressor stations, located along a natural gas pipeline. To calculate emissions, the amount of fuel used by compression is estimated based on horsepower and efficiency. Centrifugal compressor horsepower was obtained from the *Inventory of US Greenhouse Gas Emissions and Sinks: 1990 - 2005*, while the value for compressor efficiency was obtained from the *Standard Handbook of Petroleum and Natural Gas Engineering.* Emissions factors from the *API Compendium* were then applied to the calculated fuel use, thus determining emissions from transmission compressors.

Table 75 shows the distance assumptions for natural gas being transported in the pipeline transmission system from each supply region to the five demand regions.

Table 75 Pipeline Mileages for Each Demand Region for Supply Regions

Demand and Supply **Regions**	**Pipeline Mileage**
Oregon and Washington	
Western Canada	1,030
Rocky Mountains	890
Upper Midwest	
Western Canada	1,450
Rocky Mountains	1,230
MidContinent	700
Gulf Coast	1,100
New England	
LNG - New England	490
LNG - Canada Maritimes	490
Eastern Canada	670
Western Canada	2,350
Gulf Coast	1,670
New York/New Jersey/Pennsylvania	
Western Canada	1,950
Rocky Mountains	1,990
Southwest	1,800
MidContinent	1,300
Gulf Coast	1,270
East Coast LNG	400
Gulf Coast LNG	1,270
Virginia and Maryland	
Rocky Mountains	1,940
Southwest	1,600
MidContinent	1,100
Gulf Coast	1,600
East Coast LNG	200
Gulf Coast LNG	1,600

Energy use in the transmission system occurs at each compressor station along a pipeline where some of the natural gas flowing through the pipeline is typically used to fuel the compressors. **Table 76** and **Table 77** show the energy use and energy intensity estimates of natural gas transmission for each demand region for 2006 and 2020.

Table 76 2006 Energy Use and Energy Intensity of Natural Gas Transmission

Energy Use	Natural Gas Use MMBtu	Electric Use MMBtu	Total Energy Use MMBtu
Oregon/Washington	11,170,551	0	11,170,551
Upper Midwest	41,993,330	0	41,993,330
New England	45,968,634	0	45,968,634
NY/NJ/PA	48,307,307	0	48,307,307
Virginia/Maryland	19,124,037	0	19,124,037
Fuel Cycle Efficiency	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Oregon/Washington	34,514	0	34,514
Upper Midwest	42,017	0	42,017
New England	56,561	0	56,561
NY/NJ/PA	53,213	0	53,213
Virginia/Maryland	48,666	0	48,666

Table 77 2020 Energy Use and Energy Intensity of Natural Gas Transmission

Energy Use	Natural Gas Use MMBtu	Electric Use MMBtu	Total Energy Use MMBtu
Oregon/Washington	13,965,254	0	13,965,254
Upper Midwest	50,381,831	0	50,381,831
New England	28,471,752	0	28,471,752
NY/NJ/PA	46,647,776	0	46,647,776
Virginia/Maryland	14,274,952	0	14,274,952
Fuel Cycle Efficiency	Natural Gas Use Btu/MMBtu	Electric Use Btu/MMBtu	Total Energy Use Btu/MMBtu
Oregon/Washington	34,372	0	34,372
Upper Midwest	43,267	0	43,267
New England	34,435	0	34,435
NY/NJ/PA	51,385	0	51,385
Virginia/Maryland	36,326	0	36,326

Emissions in the pipeline transmission system occur mainly from compressor exhaust at compressor stations located along the pipelines. **Table 78** and **Table 79** show the total GHG emissions and emissions intensity of natural gas transmission for each demand region for 2006 and 2020. The emissions due to combustion CO_2, come from the energy used for the compressors, whereas the CH_4 (methane) emissions come from gas venting and leaks.

Table 78 2006 Total GHG Emissions and Emissions Intensity from Natural Gas Transmission

GHG Emissions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	Million Metric Tons CO_2 Equivalent					
Oregon/Washington	0.00	0.60	0.55	0.00	0.00	1.15
Upper Midwest	0.00	2.25	1.71	0.00	0.00	3.97
New England	0.00	2.46	1.39	0.00	0.00	3.86
NY/NJ/PA	0.00	2.59	1.55	0.00	0.00	4.15
Virginia/Maryland	0.00	1.03	0.67	0.00	0.00	1.70
GHG Emissions Intensity	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Oregon/Washington	0.01	4.08	3.78	0.00	0.00	7.86
Upper Midwest	0.01	4.97	3.78	0.00	0.00	8.75
New England	0.01	6.68	3.78	0.00	0.00	10.47
NY/NJ/PA	0.01	6.29	3.78	0.00	0.00	10.07
Virginia/Maryland	0.01	5.75	3.78	0.00	0.00	9.53

Table 79 2020 Total GHG Emissions and Emissions Intensity from Natural Gas Transmission

GHG Emissions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	Million Metric Tons CO_2 Equivalent					
Oregon/Washington	0.00	0.75	0.48	0.00	0.00	1.23
Upper Midwest	0.00	2.70	1.38	0.00	0.00	4.08
New England	0.00	1.53	0.98	0.00	0.00	2.51
NY/NJ/PA	0.00	2.50	1.08	0.00	0.00	3.58
Virginia/Maryland	0.00	0.77	0.47	0.00	0.00	1.23
GHG Emissions Intensity	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Oregon/Washington	0.01	4.06	2.61	0.00	0.00	6.68
Upper Midwest	0.01	5.11	2.61	0.00	0.00	7.73
New England	0.01	4.07	2.61	0.00	0.00	6.69
NY/NJ/PA	0.01	6.07	2.61	0.00	0.00	8.69
Virginia/Maryland	0.01	4.29	2.61	0.00	0.00	6.91

Distribution

Natural gas distribution uses no energy to move gas as the operating pressures are low and high pressure gas received from transmission pipelines can flow through the system with no additional compression needed. GHG emissions from distribution networks depends heavily on the type of pipe and materials that the network is made from. The Office of Pipeline Safety maintains a database of distribution pipeline mileage by type by distribution company. This data was used to calculate distribution emission factors for each of the five demand regions based on the distribution network types in each region. **Table 80** shows the different types of distribution network types and their associated emissions factors.

Table 80 CO_2 and Methane Emissions Factors for Distribution Network Systems

Distribution Network Types	CO_2 Emission Factor		CH_4 Emission Factor	
Mains - Cast Iron	2.556	Mscf/mile-yr	238.700	Mscf/mile-yr
Mains - Unprotected steel	1.183	Mscf/mile-yr	110.190	Mscf/mile-yr
Mains - Protected steel	0.033	Mscf/mile-yr	3.067	Mscf/mile-yr
Mains - Plastic	0.106	Mscf/mile-yr	9.910	Mscf/mile-yr
Services - Unprotected steel	0.018	Mscf/service	1.701	Mscf/service
Services Protected steel	0.002	Mscf/service	0.176	Mscf/service
Services - Plastic	0.000	Mscf/service	0.009	Mscf/service
Services - Copper	0.003	Mscf/service	0.254	Mscf/service

Demand regions that rely more heavily on cast iron and unprotected steel distribution systems are typically regions that have a longer history of natural gas use and therefore have older distribution systems. These systems have higher levels of distribution emissions. **Table 81** and **Table 82** show the total GHG emissions and emissions intensity of the distribution system in each demand region. The emissions are predicted to decrease between 2006 and 2020 due to improvements and overhauls of the distribution system in many regions. Since no energy is used in the distribution system, the following tables only show GHG emissions from system leaks (CH_4 and non-combustion CO_2).

Table 81 2006 Total GHG Emissions and Emissions Intensity of Natural Gas Distribution by Demand Region

GHG Emissions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	Million Metric Tons CO_2 Equivalent					
Oregon/Washington	0.00	0.00	0.46	0.00	0.00	0.46
Upper Midwest	0.00	0.00	2.06	0.00	0.00	2.06
New England	0.00	0.00	1.76	0.00	0.00	1.76
NY/NJ/PA	0.00	0.00	2.35	0.00	0.00	2.35
Virginia/Maryland	0.00	0.00	0.48	0.00	0.00	0.48
GHG Emissions Intensity	**Non-Comb. CO_2**	**Comb. CO_2**	**CH_4**	**N_2O**	**Indirect CO_2**	**Total GHG**
	lb CO_2 Equivalent/MMBtu					
Oregon/Washington	0.00	0.00	3.11	0.00	0.00	3.11
Upper Midwest	0.01	0.00	4.54	0.00	0.00	4.55
New England	0.01	0.00	4.76	0.00	0.00	4.77
NY/NJ/PA	0.01	0.00	5.71	0.00	0.00	5.72
Virginia/Maryland	0.00	0.00	2.68	0.00	0.00	2.68

Table 82 2020 Total GHG Emissions and Emissions Intensity of Natural Gas Distribution by Demand Region

GHG Emissions	Non-Comb. CO_2	Comb. CO_2	CH_4	N_2O	Indirect CO_2	Total GHG
	Million Metric Tons CO2 Equivalent					
Oregon/Washington	0.00	0.00	0.41	0.00	0.00	0.41
Upper Midwest	0.00	0.00	1.71	0.00	0.00	1.71
New England	0.00	0.00	1.64	0.00	0.00	1.64
NY/NJ/PA	0.00	0.00	1.57	0.00	0.00	1.57
Virginia/Maryland	0.00	0.00	0.28	0.00	0.00	0.28
GHG Emissions Intensity	Non-Comb. CO_2	Comb. CO_2	CH_4	N2O	Indirect CO_2	Total GHG
	lb CO_2 Equivalent/MMBtu					
Oregon/Washington	0.00	0.00	2.21	0.00	0.00	2.21
Upper Midwest	0.01	0.00	3.23	0.00	0.00	3.24
New England	0.01	0.00	4.38	0.00	0.00	4.38
NY/NJ/PA	0.01	0.00	3.81	0.00	0.00	3.81
Virginia/Maryland	0.00	0.00	1.56	0.00	0.00	1.57

Natural Gas Total Fuel Cycle Energy Use and GHG Emissions

The total estimates of the fuel cycle resource energy consumption and GHG emissions related to supplying natural gas to each of the regions are summarized in this section. The 2006 GHG emissions by process step are shown in **Table 83** and graphically in **Figure 7**. Combustion of natural gas by the final user produces 117.06 pounds of CO_2e per million Btu. As shown, the fuel cycle from well to burner tip adds another 25 to 30 percent in fuel cycle emissions to the GHG emissions from combustion. **Table 84** shows the GHG emissions by process step for 2020. These results are graphically displayed in **Figure 8**. The increase in emissions intensity in 2020 reflects changing supply patterns for each market demand region, and is particularly impacted by the increased levels of LNG imports to New England, NY/NJ/PA and VA/MD. Tables 83 and 84 also show that the total fuel cycle efficiency of supplying heating oil to each of the five market demand regions ranges between 86.8 and 91.6 percent in 2006 and between 83.7 and 90.6 percent in 2020.

Table 83 Natural Gas Fuel Cycle GHG Emissions for 2006

Fuel Cycle Stage	OR- WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
	2006 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)				
E&D	0.36	0.48	0.24	0.35	0.23
Production	14.65	15.61	10.72	12.32	9.20
Processing	4.46	5.48	4.94	6.58	5.49
Liquefaction	0.00	0.00	2.39	0.50	1.61
Shipping	0.00	0.00	0.66	0.20	0.48
Regasification	0.00	0.00	0.38	0.08	0.26
Transmission	7.86	8.75	10.47	10.07	9.53
Distribution	3.11	4.55	4.77	5.72	2.68
Final Combustion	117.06	117.06	117.06	117.06	117.06
Total Fuel Cycle Emissions	**147.52**	**151.94**	**151.64**	**152.88**	**146.54**
Total Fuel Cycle Efficiency	**91.6%**	**90.5%**	**86.8%**	**88.6%**	**88.6%**

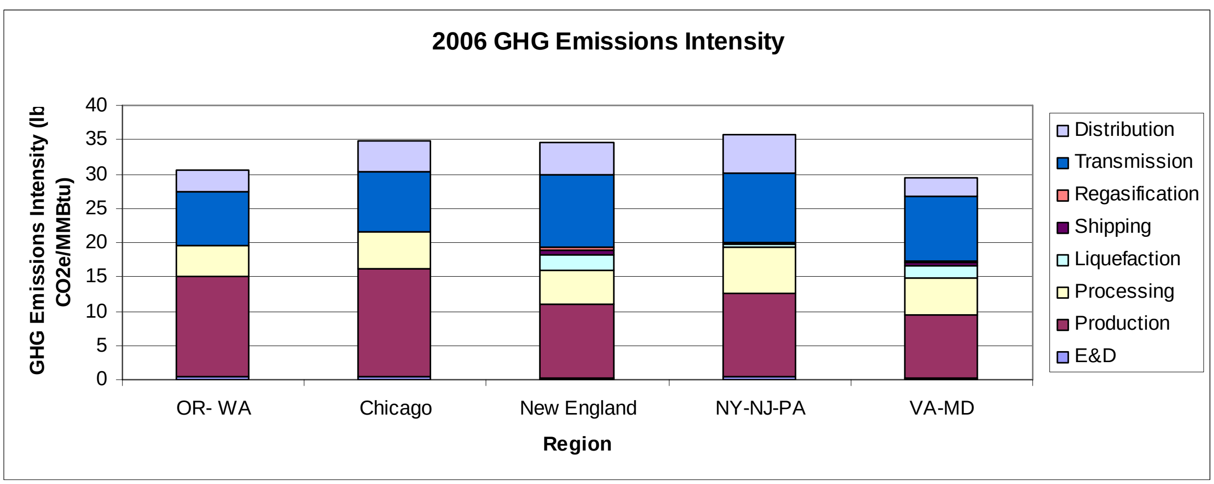


Figure 7 2006 GHG Emissions for Natural Gas Fuel Cycle by Demand Region

Table 84 Natural Gas Fuel Cycle GHG Emissions for 2020

Fuel Cycle Stage	OR- WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
	2020 GHG Emissions Intensity (lb CO_2e/MMBtu Delivered)				
E&D	0.37	0.37	0.15	0.24	0.16
Production	19.94	17.41	9.07	11.30	8.53
Processing	6.46	6.34	8.12	8.99	8.35
Liquefaction	0.00	0.00	5.18	2.79	4.49
Shipping	0.00	0.00	3.73	2.72	3.48
Regasification	0.00	0.00	0.94	0.50	0.81
Transmission	6.68	7.73	6.69	8.69	6.91
Distribution	2.21	3.24	4.39	3.82	1.57
Final Combustion	117.06	117.06	117.06	117.06	117.06
Total Fuel Cycle Emissions	152.72	152.15	155.33	156.11	151.37
Total Fuel Cycle Efficiency	90.6%	90.0%	83.7%	84.6%	84.3%

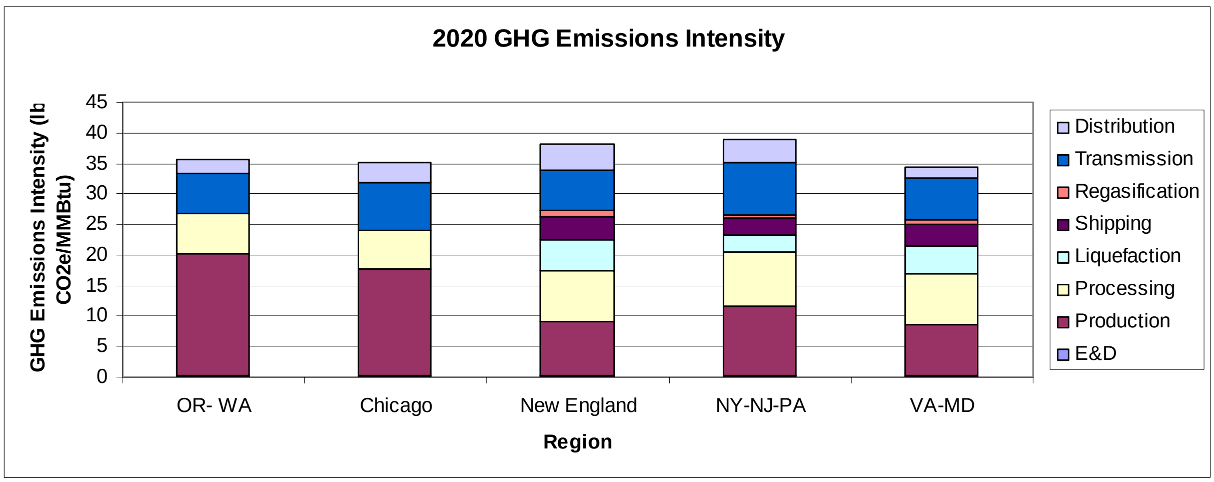


Figure 8 2020 GHG Emissions for Natural Gas Fuel Cycle by Demand Region with a 25 percent Methane Leakage Reduction

Table 85 and **Table 86** summarize the energy use and emissions by fuel cycle segment for the five demand regions in 2006. **Table 87** shows the 2020 energy use, while **Table 88** shows the 2020 GHG emissions for the five demand regions. The energy use is separated into three categories as follows:

- Natural Gas Use – use of natural gas in the fuel cycle stage
- Other Energy Use – all other sources of energy except for electricity
- Electricity Use – the quantity of electricity used on a delivered energy value basis.

The emissions are categorized into five categories as follows:

- Non-combustion CO_2 – represents emissions from processes other than combustion, specifically CO_2 emitted from oil well production and CO_2 from gas processing.

- Combustion CO_2 – represents all combustion related emissions from energy use at each stage except for indirect emissions
- CH_4 Emissions – the GWP associated with emissions of methane converted to CO_2 equivalence at a rate of 23:1.
- N_2O Emissions – the GWP associated with emissions of nitrous oxide converted to CO_2 equivalence at a rate of 296:1.
- Indirect Emissions – off-site emissions related to electricity and steam consumption.

Table 85 2006 Natural Gas Fuel Cycle Energy Use for the Five Demand Regions

Fuel Cycle Efficiency	Natural Gas Use	Other Energy Use	Electric Use	Total Energy Use
	Btu/MMBtu			
Washington/Oregon				
Exploration & Drilling	0	1,603	0	1,603
Production	26,005		4,974	30,980
Processing	15,639		1,483	17,122
Liquefaction	0		0	0
Shipping	0		0	0
Regasification	0		0	0
Transmission	34,514		0	34,514
Total	*76,158*	*1,603*	*6,458*	*84,219*
Upper Midwest				
Exploration & Drilling	0	2,400	0	2,400
Production	25,639		4,940	30,579
Processing	16,784		2,845	19,629
Liquefaction	0		0	0
Shipping	0		0	0
Regasification	0		0	0
Transmission	42,017		0	42,017
Total	*84,440*	*2,400*	*7,785*	*94,626*
New England				
Exploration & Drilling	0	1,177	0	1,177
Production	22,975		3,760	26,735
Processing	17,154		1,690	18,844
Liquefaction	20,231		0	20,231
Shipping	4,913		0	4,913
Regasification	3,246		0	3,246
Transmission	56,561		0	56,561
Total	*125,080*	*1,177*	*5,450*	*131,707*
New York/New Jersey/Pennsylvania				
Exploration & Drilling	0	1,707	0	1,707
Production	23,434		4,606	28,040
Processing	21,292		3,520	24,812
Liquefaction	4,252		0	4,252
Shipping	1,529		0	1,529
Regasification	693		0	693
Transmission	53,213		0	53,213
Total	*104,413*	*1,707*	*8,126*	*114,246*
Virginia/Maryland				
Exploration & Drilling	0	1,216	0	1,216
Production	20,995		3,993	24,988
Processing	17,381		2,462	19,843
Liquefaction	13,647		0	13,647
Shipping	3,637		0	3,637
Regasification	2,197		0	2,197
Transmission	48,666		0	48,666
Total	*106,523*	*1,216*	*6,455*	*114,195*

Table 86 2006 Natural Gas Fuel Cycle GHG Emissions for the Five Demand Regions

2006 Fuel GHG Emissions	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	lb CO_2 e/MMBtu					
Washington/Oregon						
Exploration & Drilling	0.00	0.26	0.10	0.00	0.00	0.36
Production	0.13	3.47	9.09	0.02	1.95	14.65
Processing	0.82	2.10	0.95	0.02	0.58	4.46
Liquefaction	0.00	0.00	0.00	0.00	0.00	0.00
Shipping	0.00	0.00	0.00	0.00	0.00	0.00
Regasification	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.01	4.08	3.78	0.00	0.00	7.86
Distribution	0.00	0.00	3.11	0.00	0.00	3.11
Total	*0.95*	*9.92*	*17.01*	*0.04*	*2.53*	*30.45*
Upper Midwest						
Exploration & Drilling	0.00	0.39	0.09	0.00	0.00	0.48
Production	0.10	3.48	10.08	0.02	1.93	15.61
Processing	0.88	2.36	1.10	0.02	1.11	5.48
Liquefaction	0.00	0.00	0.00	0.00	0.00	0.00
Shipping	0.00	0.00	0.00	0.00	0.00	0.00
Regasification	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.01	4.97	3.78	0.00	0.00	8.75
Distribution	0.01	0.00	4.55	0.00	0.00	4.55
Total	*0.99*	*11.20*	*19.60*	*0.04*	*3.05*	*34.88*
New England						
Exploration & Drilling	0.00	0.19	0.05	0.00	0.00	0.24
Production	0.06	3.34	5.83	0.01	1.47	10.72
Processing	1.03	2.33	0.90	0.02	0.66	4.94
Liquefaction	0.00	2.37	0.00	0.02	0.00	2.39
Shipping	0.00	0.66	0.00	0.00	0.00	0.66
Regasification	0.00	0.38	0.00	0.00	0.00	0.38
Transmission	0.01	6.68	3.78	0.00	0.00	10.47
Distribution	0.01	0.00	4.77	0.00	0.00	4.77
Total	*1.10*	*15.95*	*15.33*	*0.05*	*2.13*	*34.57*
New York/New Jersey/Pennsylvania						
Exploration & Drilling	0.00	0.28	0.07	0.00	0.00	0.35
Production	0.06	3.42	7.02	0.02	1.80	12.32
Processing	1.27	2.70	1.21	0.02	1.38	6.58
Liquefaction	0.00	0.50	0.00	0.00	0.00	0.50
Shipping	0.00	0.20	0.00	0.00	0.00	0.20
Regasification	0.00	0.08	0.00	0.00	0.00	0.08
Transmission	0.01	6.29	3.78	0.00	0.00	10.07
Distribution	0.01	0.00	5.71	0.00	0.00	5.72
Total	*1.34*	*13.47*	*17.78*	*0.05*	*3.18*	*35.82*
Virginia/Maryland						
Exploration & Drilling	0.00	0.20	0.03	0.00	0.00	0.23
Production	0.02	3.33	4.27	0.02	1.56	9.20
Processing	1.16	2.33	1.02	0.02	0.96	5.49
Liquefaction	0.00	1.60	0.00	0.01	0.00	1.61
Shipping	0.00	0.48	0.00	0.00	0.00	0.48
Regasification	0.00	0.26	0.00	0.00	0.00	0.26
Transmission	0.01	5.75	3.78	0.00	0.00	9.53
Distribution	0.00	0.00	2.67	0.00	0.00	2.68
Total	*1.19*	*13.94*	*11.77*	*0.05*	*2.53*	*29.48*

Table 87 2020 Natural Gas Fuel Cycle Energy Use for the Five Demand Regions

Fuel Cycle Efficiency	Natural Gas Use	Other Energy Use	Electric Use	Total Energy Use
	Btu/MMBtu			
Washington/Oregon				
Exploration & Drilling	0	1,087	0	1,087
Production	29,915		4,983	34,898
Processing	21,045		2,133	23,178
Liquefaction	0		0	0
Shipping	0		0	0
Regasification	0		0	0
Transmission	34,372		0	34,372
Total	*85,333*	*1,087*	*7,116*	*93,536*
Upper Midwest				
Exploration & Drilling	0	1,369	0	1,369
Production	27,923		4,754	32,678
Processing	19,463		2,773	22,235
Liquefaction	0		0	0
Shipping	0		0	0
Regasification	0		0	0
Transmission	43,267		0	43,267
Total	*90,653*	*1,369*	*7,527*	*99,549*
New England				
Exploration & Drilling	0	689	0	689
Production	24,300		2,142	26,442
Processing	21,447		5,430	26,877
Liquefaction	43,810		0	43,810
Shipping	22,775		0	22,775
Regasification	7,974		0	7,974
Transmission	34,435		0	34,435
Total	*154,741*	*689*	*7,572*	*163,001*
New York/New Jersey/Pennsylvania				
Exploration & Drilling	0	1,017	0	1,017
Production	24,152		2,679	26,831
Processing	23,225		5,917	29,142
Liquefaction	23,575		0	23,575
Shipping	17,854		0	17,854
Regasification	4,216		0	4,216
Transmission	51,385		0	51,385
Total	*144,408*	*1,017*	*8,596*	*154,022*
Virginia/Maryland				
Exploration & Drilling	0	798	0	798
Production	23,717		2,270	25,986
Processing	21,416		5,649	27,065
Liquefaction	37,962		0	37,962
Shipping	21,666		0	21,666
Regasification	6,884		0	6,884
Transmission	36,326		0	36,326
Total	*147,971*	*798*	*7,919*	*156,688*

Table 88 2020 Natural Gas Fuel Cycle GHG Emissions for the Five Demand Regions

2020 Fuel GHG Emissions	Non-Comb. CO_2	Comb. CO_2	CH_4*	N_2O	Indirect CO_2	Total GHG
	lb CO_2 e/MMBtu					
Washington/Oregon						
Exploration & Drilling	0.00	0.18	0.19	0.00	0.00	0.37
Production	0.25	3.99	13.72	0.02	1.95	19.94
Processing	1.81	2.83	0.96	0.02	0.84	6.46
Liquefaction	0.00	0.00	0.00	0.00	0.00	0.00
Shipping	0.00	0.00	0.00	0.00	0.00	0.00
Regasification	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.01	4.06	2.61	0.00	0.00	6.68
Distribution	0.00	0.00	2.21	0.00	0.00	2.21
Total	*2.08*	*11.06*	*19.69*	*0.05*	*2.79*	*35.66*
Upper Midwest						
Exploration & Drilling	0.00	0.22	0.15	0.00	0.00	0.37
Production	0.18	3.87	11.48	0.02	1.86	17.41
Processing	1.60	2.68	0.95	0.02	1.09	6.34
Liquefaction	0.00	0.00	0.00	0.00	0.00	0.00
Shipping	0.00	0.00	0.00	0.00	0.00	0.00
Regasification	0.00	0.00	0.00	0.00	0.00	0.00
Transmission	0.01	5.11	2.61	0.00	0.00	7.73
Distribution	0.01	0.00	3.23	0.00	0.00	3.24
Total	*1.79*	*11.89*	*18.42*	*0.04*	*2.95*	*35.09*
New England						
Exploration & Drilling	0.00	0.11	0.04	0.00	0.00	0.15
Production	0.05	3.48	4.69	0.01	0.84	9.07
Processing	2.33	2.91	0.73	0.02	2.13	8.12
Liquefaction	0.00	5.13	0.01	0.04	0.00	5.18
Shipping	0.00	3.73	0.00	0.00	0.00	3.73
Regasification	0.00	0.93	0.00	0.01	0.00	0.94
Transmission	0.01	4.07	2.61	0.00	0.00	6.69
Distribution	0.01	0.00	4.38	0.00	0.00	4.39
Total	*2.40*	*20.37*	*12.46*	*0.08*	*2.97*	*38.27*
New York/New Jersey/Pennsylvania						
Exploration & Drilling	0.00	0.17	0.07	0.00	0.00	0.24
Production	0.12	3.34	6.78	0.01	1.05	11.30
Processing	2.80	3.01	0.84	0.02	2.32	8.99
Liquefaction	0.00	2.76	0.00	0.02	0.00	2.79
Shipping	0.00	2.72	0.00	0.00	0.00	2.72
Regasification	0.00	0.49	0.00	0.00	0.00	0.50
Transmission	0.01	6.07	2.61	0.00	0.00	8.69
Distribution	0.01	0.00	3.81	0.00	0.00	3.82
Total	*2.93*	*18.57*	*14.12*	*0.06*	*3.37*	*39.04*
Virginia/Maryland						
Exploration & Drilling	0.00	0.13	0.03	0.00	0.00	0.16
Production	0.05	3.46	4.13	0.01	0.89	8.53
Processing	2.48	2.88	0.76	0.02	2.21	8.35
Liquefaction	0.00	4.44	0.01	0.04	0.00	4.49
Shipping	0.00	3.48	0.00	0.00	0.00	3.48
Regasification	0.00	0.81	0.00	0.00	0.00	0.81
Transmission	0.01	4.29	2.61	0.00	0.00	6.91
Distribution	0.00	0.00	1.57	0.00	0.00	1.57
Total	*2.53*	*19.49*	*9.11*	*0.07*	*3.10*	*34.30*

4
BIOFUEL FUEL CYCLE ANALYSIS

Introduction

This section describes the results and analytical approach of a full fuel cycle analysis of the energy used and GHG emissions associated with supplying biofuel to five designated locations throughout the United States.

Bioheat® fuel is the industry-accepted term for any blend of pure biodiesel combined with conventional high or low sulfur home heating oil, with a minimum of 2 percent. Biodiesel can be used in home heating oil systems safely with no modifications to the fuel tanks, pumps or burners in concentrations up to 5 percent biodiesel with only minimal precautions. For Bioheat® fuel blends between 6 percent and 20 percent, minor changes (including a pump with proper seals) may be required. Bioheat® fuel blends higher than 20 percent are technically feasible with user modifications to ensure materials compatibility and adaptation to accommodate a higher cold flow temperature.[27]

Analytical Framework

In this section fuel cycle energy and emissions are estimated for 100 percent biofuel. The average emissions of blended fuel are also estimated based on averaging the energy use and emissions of home heating oil described in the previous section. The detailed analysis of biofuel production energy use and emissions is based on a study undertaken by the National Renewable Energy Laboratory (NREL).[28] The results were updated based on improvements in soybean agriculture yields since the study was prepared. For the 2020 forecast, it was assumed that there would be evolutionary improvements in agriculture yield, processing efficiencies, and an aggressive use of biodiesel fuel in the transport operations.

The biofuel fuel cycle consists of the following general activities:

- Biofuel Agriculture – consisting of all of the activities associated with planting, tending, and harvesting soybeans or, in the case of the West Coast in 2020, rapeseed

- Processing (Bio-refining) – consisting of crushing which separates the raw oil from the seed meal and refining of the oil to biofuel by a process called *transesterifcation*.

[27] National Biodiesel Board Website, http://www.biodiesel.org/markets/hom/faqs.asp
[28] John Sheehan, *et al.*, *Life Cycle Inventory of Biodiesel and Petroleum Diesel for Use in an Urban Bus*, National Renewable Energy Laboratory, May 1998.

- Transportation and Storage – of the soybeans or rapeseed to the crushing facility, the transportation of the raw oil to the refinery, and the final transportation of biofuel to home heating customers

- Blending with Conventional or Low-Sulfur Heating Oil – the final biofuel product is generally a blend of petroleum based heating oil and biofuel.

Biofuel Agriculture

Table 89 shows the basic yield and location assumptions for this analysis. It is assumed that, in the near term, biofuel from dedicated crops will be made from soybeans. For each of the demand centers used in this study, the closest soybean production locations are assumed to supply the feedstock for biofuel production. The NREL average U.S. assumptions are shown in the final column of the table. Soybean yields for the production locations have been updated from the 1995 assumptions used by NREL to the most recent data available.[29] Soybeans are assumed to travel 75 miles to the crusher where the raw oil is extracted. The distance to market is estimated for each demand center. This is assumed to be the total distance to market. In other words, the biofuel refining may occur closer to the production regions or to the demand centers, but the total oil transport will be roughly the same.

Table 89 Biofuel Yield and Location Assumptions

Production/Transport 2006 Assumptions	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD	NREL U.S. Avg. 1995
Production Locations	IA,AR	IL, IA	DE, IL	DE, IL	DE, SC	U.S. Avg.
Yield, bu/acre	44.3	49.8	46.3	46.3	35.0	38.00
Transport to Crusher, miles	75	75	75	75	75	75
Transport to Market, miles	1,740	248	680	530	200	571

Table 90 shows the energy requirements for soybean agriculture for each production region associated with its demand center. It was assumed for this study that the energy requirements developed by NREL are inversely proportional to the estimated crop yield within each region.. Therefore, with the trends in higher soybean yields, the agriculture energy requirements are assumed to be lower than calculated by NREL. **Table 91** shows the associated GHG emissions.

Table 90 Energy Requirements for Soybean Agriculture per MMBtu of Biofuel Delivered

Agriculture Energy Use Btu/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD	U.S. Avg. 1995
Natural Gas	2	1	2	2	2	2
Electricity	1,260	1,120	1,205	1,205	1,592	1,467
Diesel Fuel	21,011	18,688	20,102	20,102	26,564	24,467
Gasoline	11,278	10,031	10,791	10,791	14,259	13,133
Propane	802	713	767	767	1,013	933
Fertilizer & Chemicals	7,488	6,661	7,165	7,165	9,467	8,720
Total Ag Energy	41,840	37,215	40,031	40,031	52,898	48,722

[29] *Soystats*, American Soybean Association, http://www.soystats.com/2005/page_14.htm

Table 91 GHG Emissions for Soybean Agriculture per MMBtu of Biofuel Delivered

Agriculture Emissions lb CO_2e/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD	U.S. Avg 1995	GHG Emission Factors lb CO_2e /MMBtu
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00	117
Electricity	0.50	0.44	0.47	0.47	0.63	0.58	394
Diesel Fuel	3.39	3.01	3.24	3.24	4.28	3.95	161
Gasoline	1.76	1.57	1.69	1.69	2.23	2.05	156
Propane	0.11	0.10	0.11	0.11	0.14	0.13	137
Fertilizer & Chemicals	0.88	0.78	0.84	0.84	1.11	1.02	117
Total Ag Emissions	6.63	5.90	6.35	6.35	8.39	7.72	

For the 2020 estimates, it was assumed that there would be a 20 percent increase in soybean yields. This increase was based on an analysis of the historical improvement to soybean yields over the last 20 years. Because soybeans are not grown in the West, it was assumed that future biofuel for the west coast would come from a different crop, such as rapeseed oil, in order to minimize the long transport distances required to bring soybean oil to the west coast. These changes result in the 2020 energy and emissions factors for agriculture shown in **Table 92** and **Table 93**.

Table 92 2020 Energy Requirements for Biofuel Crop Agriculture

Agriculture Energy Use Btu/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD	U.S. Avg. 1995
Natural Gas	1	1	1	1	2	2
Electricity	1,267	934	1,004	1,004	1,327	1,467
Diesel Fuel	21,130	15,573	16,752	16,752	22,137	24,467
Gasoline	11,342	8,360	8,992	8,992	11,883	13,133
Propane	806	594	639	639	844	933
Fertilizer & Chemicals	7,531	5,550	5,970	5,970	7,890	8,720
Total Ag Energy	42,078	31,012	33,359	33,359	44,082	48,722

Table 93 2020 GHG Emissions for Biofuel Crop Agriculture

Agriculture Emissions lb CO_2e/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD	U.S. Avg. 1995
Natural Gas	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.50	0.37	0.40	0.40	0.52	0.58
Diesel Fuel	3.41	2.51	2.70	2.70	3.57	3.95
Gasoline	1.77	1.31	1.41	1.41	1.86	2.05
Propane	0.11	0.08	0.09	0.09	0.12	0.13
Fertilizer & Chemicals	0.88	0.65	0.70	0.70	0.92	1.02
Total Ag Emissions	6.67	4.92	5.29	5.29	6.99	7.72

Biofuel Processing

There are two main components of soybean processing to biofuel – crushing and refining. The soybean crushing actually consists of a number of processing steps as follows:

- Soybean receiving and storage
- Soybean preparation
- Soybean oil extraction
- Soybean meal processing
- Soybean oil recovery
- Solvent recovery
- Oil degumming
- Waste treatment.

The soybean meal is used as an animal feed. The soybean oil, if it is destined for biofuel production, must be refined at a dedicated biofuel refinery using a process called *transesterification*. The refining also includes a number of processing steps:

- Alkali refining of crude soybean oil
- Transesterification
- Methyl ester purification
- Glycerine recovery
- Methanol recovery
- Waste treatment.

The energy requirements for soybean based biofuel processing are shown in **Table 94**. The associated GHG emissions are shown in **Table 95.** Both estimates are based directly on the NREL biofuels analysis[30]. No regional variation is assumed in the crushing and refining stages of the fuel cycle.

For the 2020 biofuel energy and emissions forecast, it was assumed that the process would achieve an across the board 20 percent improvement in energy efficiency. This assumption represents an order of magnitude estimate of possible improvements to biofuel agriculture and energy processing. There have been no detailed studies on how these improvements might be derived.

[30] John Sheehan, *et al.*, *Life Cycle Inventory of Biodiesel and Petroleum Diesel for Use in an Urban Bus*, National Renewable Energy Laboratory, May 1998.

Table 94 2006 Biofuel Processing Energy Requirements

Soybean Processing Energy Use Btu/MMBtu	NREL Energy Btu/MMBtu
Soybean Crushing	
Electricity	21,067
Steam	29,467
Natural Gas	28,533
Hexane	1,131
Biorefinery	
Electricity	7,853
Steam	39,600
Methanol	78,573
Other Chemicals	25,493
Total Processing Energy	231,717

Table 95 2006 Biofuel Processing GHG Emissions

Processing Emissions lb CO_2e/MMBtu	NREL U.S. Average
Soybean Crushing	
Electricity	8.30
Steam	4.31
Natural Gas	3.34
Hexane	0.17
Biorefinery	
Electricity	3.09
Steam	5.79
Methanol	11.12
Other Chemicals	2.98
Total Processing Energy	39.10

Biofuel Transport

There are several transportation and storage steps in the biofuel fuel cycle. First soybeans must be transported from the farm to the crusher. Soybean crushing facilities are generally located within major soybean producing areas. Typically, soybeans are transported 75 miles or less in heavy diesel trucks. A comparatively small amount of electric energy is used in loading and unloading.

Next, the crude soybean oil must be transported to the biofuel refinery. After refining, the biofuel is transported to the final demand centers. The exact location of biofuel refineries of the future is uncertain. They could be co-located at the crushing facilities, or they could be located near the distribution centers or anywhere in between. For their analysis, NREL assumed that the transport of soybean oil and refined biofuel would require the same transportation modes and the same energy requirements. In other words, it doesn't matter where the biofuel refinery is located, the total oil transportation, by truck, rail, and tanker would be essentially the same. These total oil transport distances for each demand center were previously shown in **Table 89**.

The energy requirements for these transport steps are shown in **Table 96**. The GHG emissions are shown in **Table 97**. The only regional variations are in the intermediate transport distances reflecting the distance between the demand center and the nearest soybean producing center.

Table 96 2006 Transport and Storage Energy Use for Biofuel by Demand Center

Transport and Storage Energy Use Btu/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD	Energy Btu/MMBtu
Unloading and Transport						
Electricity	0	0	0	0	0	0
Diesel Oil	3,387	3,387	3,387	3,387	3,387	3,387
Intermediate Transport						
Electricity	1	0	1	0	0	0
Diesel Fuel	21,940	3,127	8,574	6,683	2,522	7,200
Retail Transport and Storage						
Electricity	1	1	1	1	1	1
Diesel Oil	3,333	3,333	3,333	3,333	3,333	4,387
Total Transport Energy	28,663	9,848	15,296	13,404	9,243	14,975

Source: Unloading and transport and intermediate transport from NREL; retail transport is from the oil analysis in Section 2.

Table 97 2006 Biofuel Transport GHG Emissions

Transport and Storage Emissions lb CO_2e/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD	NREL U;S Average	lb CO_2e/ MMBtu
Unloading and Transport							
Electricity	0.00	0.00	0.00	0.00	0.00	0.00	394.012
Diesel Oil	0.55	0.55	0.55	0.55	0.55	0.55	161.269
Intermediate Transport							
Electricity	0.00	0.00	0.00	0.00	0.00	0.00	394.012
Diesel Fuel	3.54	0.50	1.38	1.08	0.41	1.16	161.269
Retail Transport and Storage							
Electricity	0.00	0.00	0.00	0.00	0.00	0.00	394.012
Diesel Oil	0.54	0.54	0.54	0.54	0.54	0.71	161.269
Total Transport Energy	4.62	1.59	2.47	2.16	1.49	2.42	

The only change assumed for the 2020 forecast is for the OR-WA demand center. It was assumed that biofuel production would come from a Western crop such as rapeseed oil. This change reduces the intermediate transportation requirements from 1740 miles to 250 miles. The energy and emissions requirements for biofuel transport in OR-WA are thus reduced to 28,663 Btu/MMBtu of biofuel delivered and 4.62 lb CO_2e/MMBtu.

Biofuel Blending with Conventional and Low Sulfur Heating Oil

The use of pure biofuel is technically feasible with appropriate precautions in fuel handling and materials compatibility. However, it is more likely that biofuel will be blended with petroleum based heating oil. As previously indicated, this blending is likely to be in the ratio of 2-20 percent biofuel.

Based on the heating oil fuel cycle analysis in the previous section, the GHG emissions values for B20 (20 percent biofuel) are shown in **Table 98**. The use of pure biofuel could reduce full fuel cycle GHG emissions by about 75 percent. The use of blended B20 reduces GHG emissions by about 15 percent.

Table 98 Effect of Blending 20 percent Biofuel to Home Heating Oil

Assumed Percentage Bio-Fuel	**20%**				
BioFuel Blending Estimate lb CO_2e/MMBtu	**OR-WA**	**Upper Midwest**	**New England**	**NY-NJ-PA**	**VA-MD**
2006					
100% Petroleum Based	193.18	186.93	187.04	186.79	186.84
100% Biomass Based	50.36	46.59	47.92	47.61	48.98
Blended Fuel Emissions	**164.62**	**158.86**	**159.21**	**158.95**	**159.27**
2020					
100% Petroleum Based	191.41	190.56	190.83	190.59	190.67
100% Biomass Based	39.55	37.79	39.04	38.73	39.76
Blended Fuel Emissions	**161.04**	**160.01**	**160.47**	**160.22**	**160.49**

Biofuel Fuel Cycle Energy and Emissions Summary

The summary biofuel results for 2006 are shown in **Table 99** and **Table 100**. The results are compared graphically in **Figure 9**. Based on current practices, biofuel production and delivery would require 279 to 302 thousand Btus per million Btu of biofuel delivered to the home heating customer. There would be no GHG emissions from the final use of this sustainable fuel. All of the carbon produced by combustion of biodiesel has been taken out of the air as a result of photsynthesis during the growing season. When the fuel is combusted, an amount of CO_2 is added back to the air that is exactly equal – producing a zero net impact. The only GHG emissions would come from the fuel production and delivery, which would range from 46.6 to 50.4 lbs CO_2e/MMBtu.

Table 99 Summary of Biofuel Production and Transport Energy Requirements for 2006

Summary Energy Use Btu/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
Agriculture	41,840	37,215	40,031	40,031	52,898
Transport to Crusher	3,387	3,387	3,387	3,387	3,387
Crushing (Oil Extraction)	80,197	80,197	80,197	80,197	80,197
Intermediate Transport	21,942	3,127	8,575	6,683	2,522
Bio-Refining	151,520	151,520	151,520	151,520	151,520
Retail Transport	3,334	3,334	3,334	3,334	3,334
Total Fuel Cycle Energy	302,220	278,780	287,044	285,153	293,858
Fuel Cycle Efficiency	76.8%	78.2%	77.7%	77.8%	77.3%

Table 100 Summary of Biofuel Fuel Cycle GHG Emissions for 2006

Summary Emissions lb CO_2e/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
Agriculture	6.63	5.90	6.35	6.35	8.39
Transport to Crusher	0.55	0.55	0.55	0.55	0.55
Crushing (Oil Extraction)	16.11	16.11	16.11	16.11	16.11
Intermediate Transport	3.54	0.50	1.38	1.08	0.41
Bio-Refining	22.99	22.99	22.99	22.99	22.99
Retail Transport	0.54	0.54	0.54	0.54	0.54
Total Upstream Emissions	50.36	46.59	47.92	47.61	48.98
Bio-Fuel Combustion	0.00	0.00	0.00	0.00	0.00
Total Fuel Cycle Emissions	50.36	46.59	47.92	47.61	48.98

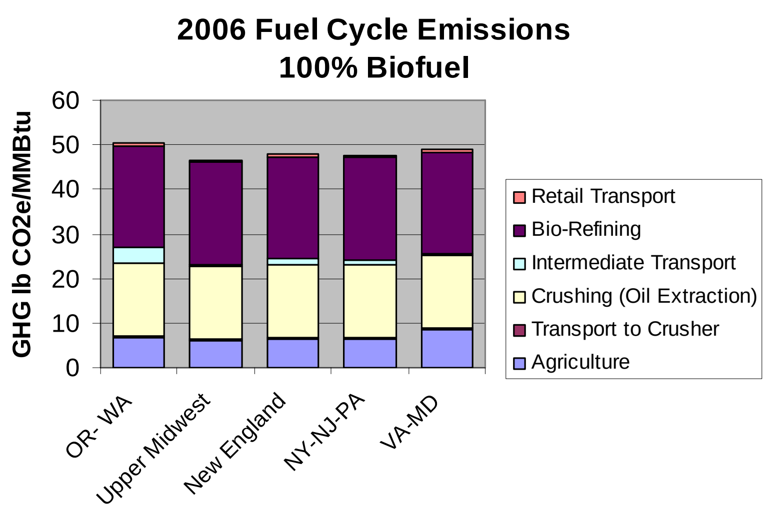


Figure 9 Summary of Biofuel Fuel Cycle GHG Emissions by Demand Region for 2006

The 2020 summary forecast is shown similarly in **Table 101**, **Table 102**, and **Figure 10**. Fuel cycle energy use and emissions are reduced by 18-21 percent.

Table 101 Summary of Biofuel Production and Transport Energy Requirements for 2020

Summary Energy Use Btu/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
Agriculture	42,078	31,012	33,359	33,359	44,082
Transport to Crusher	3,387	3,387	3,387	3,387	3,387
Crushing (Oil Extraction)	64,158	64,158	64,158	64,158	64,158
Intermediate Transport	3,153	3,127	8,575	6,683	2,522
Bio-Refining	121,216	121,216	121,216	121,216	121,216
Retail Transport	3,334	3,334	3,334	3,334	3,334
Total Fuel Cycle Energy	237,325	226,234	234,029	232,137	238,699
Fuel Cycle Efficiency	80.8%	81.6%	81.0%	81.2%	80.7%

Table 102 Summary of Biofuel Fuel Cycle GHG Emissions for 2020

Summary Emissions lb CO_2e/MMBtu	OR-WA	Upper Midwest	New England	NY-NJ-PA	VA-MD
Agriculture	6.67	4.92	5.29	5.29	6.99
Transport to Crusher	0.55	0.55	0.55	0.55	0.55
Crushing (Oil Extraction)	12.89	12.89	12.89	12.89	12.89
Intermediate Transport	0.51	0.50	1.38	1.08	0.41
Bio-Refining	18.39	18.39	18.39	18.39	18.39
Retail Transport	0.54	0.54	0.54	0.54	0.54
Total Upstream Emissions	39.55	37.79	39.04	38.73	39.76
Bio-Fuel Combustion	0.00	0.00	0.00	0.00	0.00
Total Fuel Cycle Emissions	39.55	37.79	39.04	38.73	39.76

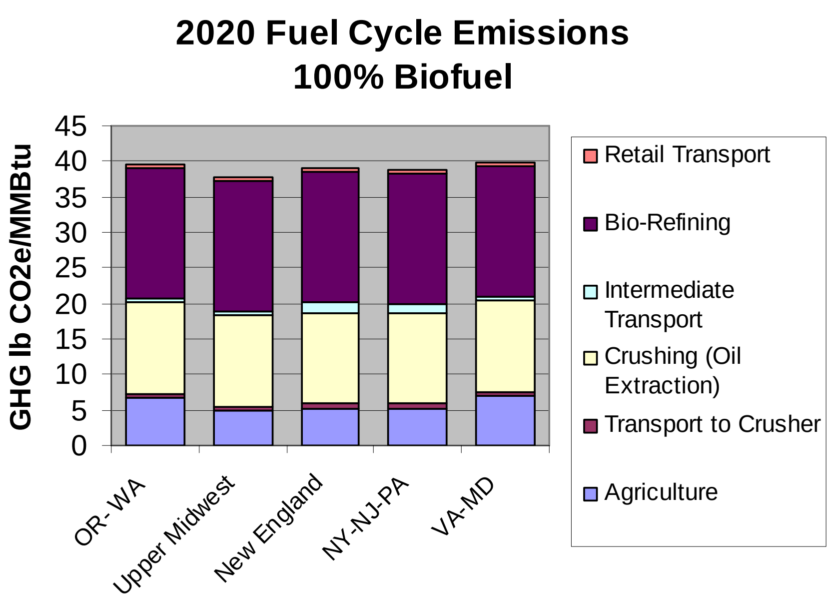


Figure 10 Summary of Biofuel Fuel Cycle GHG Emissions by Demand Region for 2020

5
RESIDENTIAL END-USE EFFICIENCIES[31]

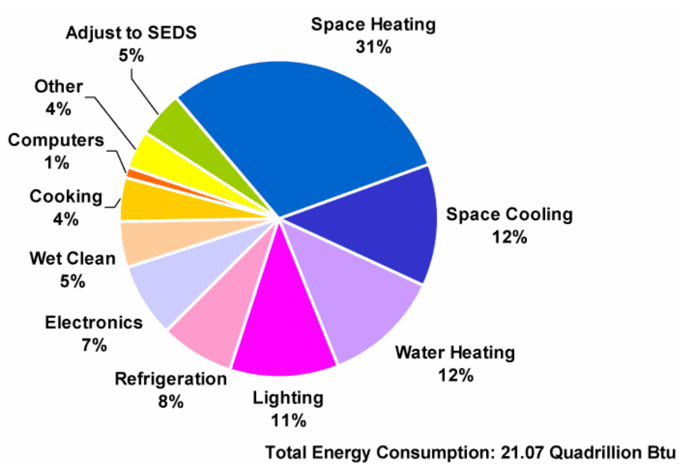
Introduction

The previous sections have established the energy and emissions impact of bringing heating oil, natural gas, and biofuel through each fuel cycle stage to the burner tip. This section analyzes the energy and emission impacts of the efficiency of residential use of these fuels. The amount of fuel used by a heating system, and resulting CO_2 emitted, is dependent upon the location, building annual heat and hot water demand, and system efficiency. In this section, an analysis of fuel use has been done primarily to illustrate the fuel use of new, upgraded systems relative to the older installed base of systems. Comparisons of energy and emissions resulting from three different system types for natural gas, heating oil, and biofuel have been made for a standard residence.

Residential Energy Systems

Examining the future of residential energy systems one must start with current energy uses. **Figure 11** shows that heating, cooling and domestic hot water (DHW) use account for 55 percent of the energy consumed by our homes[32]. Today, it is widely accepted that efficient energy utilization in existing and new homes is essential to preserving our way of life and to ensuring a sustainable future. The U.S. Environmental Protection Agency and its Science Advisory Board have consistently ranked indoor air pollution among the top five environmental risks to public health.

Figure 11 2005 Residential Buildings Energy End-Use



31 This section is based on the work of Dr. Thomas Butcher at Brookhaven National Laboratory

32 2007 Buildings Energy Data Book, U.S. Department of Energy, 2005 Residential Buildings Energy End-Use

The advent of new hydronic technologies that improve energy efficiency, simplify installation and provide multiple energy supply (heating, DHW, cooling, pool heating, deicing, etc.) has led to a resurgence in interest in the use of hydronic systems. Looking to the future, hydronic systems also offer strong potential for integration with solar thermal systems. The following elements have led to the conclusion that integrated hydronic systems are a key residential technology of the future and thus the basis for the end-use comparisons in this report:

- Energy Efficiency: A heating/cooling system that maintains an entire building at the same temperature wastes energy and doesn't give occupants with individual comfort preferences any choice. Hydronic systems are easily segmented in to zones using today's engineered plastics and simple zone valves. Such systems can reduce energy consumption by maintaining setback air temperatures in unoccupied areas.

- Indoor air quality (IAQ): One of the leading complaints from owners of forced-air systems is the amount of dust and other airborne pollutants their systems distribute through the house. This can be the result of filter maintenance, but it clearly demonstrates one of the potential IAQ problems of forced-air distribution systems.

- Comfort: Hydronic heating has long enjoyed a reputation for providing thermal comfort. Some hydronic systems provide comfort by warming the surfaces within a room (floors, tub surrounds, etc.) as well as the room's air (by radiation and/or fan coils).

Boiler and DHW System Assessment

The main measure that is used for identifying the efficiency of heating systems in the U.S. is termed the Annual Fuel Utilization Efficiency (AFUE). A standard for this measure is maintained by the American Society of Heating Refrigeration and Air Conditioning Engineers (ASHRAE)[33] and this is adapted for a federal labeling procedure by the U.S. Department of Energy. The AFUE measure is based upon a heat loss method and involves measurement of excess air and flue gas temperature over operating cycles considered typical of national average conditions. For appliances which have as their sole function heating domestic hot water (DHW) there is a separate ASHRAE procedure[34] which has also been adopted as part of a national labeling procedure.

Presently there is under development an ASHRAE test standard for commercial boilers which provides an interesting alternative methodology. A boiler heat input / output curve is developed from test data. This curve, for most boilers is linear, providing the need to measure only steady state, full load efficiency and energy input at an idle condition. The procedure provides for optional tests at part load and steady state, full load and at different supply water temperatures. In the case where the boiler control changes water temperature a series of different performance curves are produced, each for one temperature. These curves are then applied to specific buildings with an analysis procedure considering building type, location, design heat load, boiler size; number of boilers installed, and control strategy.

[33] Method of Testing for Annual Fuel Utilization Efficiency of Residential Central Furnaces and Boilers, American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE), Standard 103-1993, 1993.

[34] Methods of Testing for Rating Residential Water Heaters. American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE), Standard 118.2-2006, 2006.

The colder regions of America, like the Northeast, have seen widespread use of hydronic heating systems. These systems are often integrated to provide heating and DHW. There are multiple configurations used for producing DHW including, for example, use of a domestic water coil inserted in the heating boiler (low cost, traditional system); use of an indirect domestic hot water tank heated from the heating boiler; and use of a separate, fuel or electric fired hot water heater. There are also an increasing range of boiler control configuration options available including outdoor reset, cold start, thermal purge, and variable setpoint differential.

Brookhaven National Laboratory[35] developed input/output performance maps for integrated (heat and DHW) hydronic residential systems and completed analyses to demonstrate how these results can be used to calculate the annual fuel use with different systems. A key rationale for this work was the opinion that heating only performance measures (AFUE) lead to low estimates of the energy savings potential of modern, integrated systems, particularly where advanced controls are used. A direct load emulation approach to measure the performance of hydronic systems and develop appliance system performance curves was conducted. A wide range of system types have been tested including conventional boilers with "tankless" internal coils for domestic hot water production, boilers with indirect external storage tanks, tank type water heaters which may also be used for space heating, condensing oil- and gas-fired systems, and systems with custom control features.

The Brookhaven test system shown in **Figure 12** may include a boiler and water storage tank, a boiler with an internal coil for hot water production, a tank type water heater used also for domestic hot water, or any other integrated system. Fuel input is measured using a correolis flow meter against a precision balance. The fuel heating value and density are measured using the ASTM procedures.

Systems tested have included boilers with tankless coils, boilers with indirect tanks, tank type water heaters which are also used for space heating, and systems which include separate, fired heating boilers and water heaters. The domestic hot water and space heating loads are imposed on the equipment being tested with a computer-controlled system that allows programming of any type of cyclic or steady load pattern. Load patterns could include, for example: hourly domestic hot water draws; heat demand every 2 hours; or integrated heat and domestic hot water draw patterns over a 72 hour period. Many other types of draw patterns can be and have been evaluated. For the domestic hot water load the draw is initiated and ended with a simple solenoid valve and a programmed modulating valve is used to control the draw rate. For the heating load the systems are setup with a closed loop and plate heat exchanger. Cooling water flow of the open side of the exchanger is used to control the duration and magnitude of the load. Energy output is measured using cooling water input and output temperatures and a weight scale and all data is collected on the data acquisition system for later analysis. Results of all tests indicate that a linear input/output relation is a good approximation for the overall performance at a specific boiler temperature setting. With this, the performance of any system can be defined by two parameters – the steady state, full load thermal efficiency (η_{th}) and the idle loss. Idle loss is the energy input required when the system has no heat or domestic hot water load, expressed as a percentage of the steady state full load input. The idle loss for the systems tested has been found to range from a very low value of 0.15 percent to a high of almost 5 percent. The highest value of idle loss was found in a cast iron boiler which is poorly insulated and has a tankless coil for domestic hot water. The presence of the tankless coil required the boiler to remain hot (~ 150 F) even during the summer months to meet the domestic hot water

35 Performance of Integrated Hydronic Systems, Project Report, May 1, 2007, Thomas A. Butcher, Brookhaven National Laboratory

demand. The lowest level of idle loss was found for a boiler with an indirect hot water tank. The entire system was very well insulated and the system includes a control scheme which purges heat from the boiler to either the domestic tank or the last zone that demanded heat as appropriate. This purge occurs after a heat call has ended and reduces off-cycle boiler energy losses.

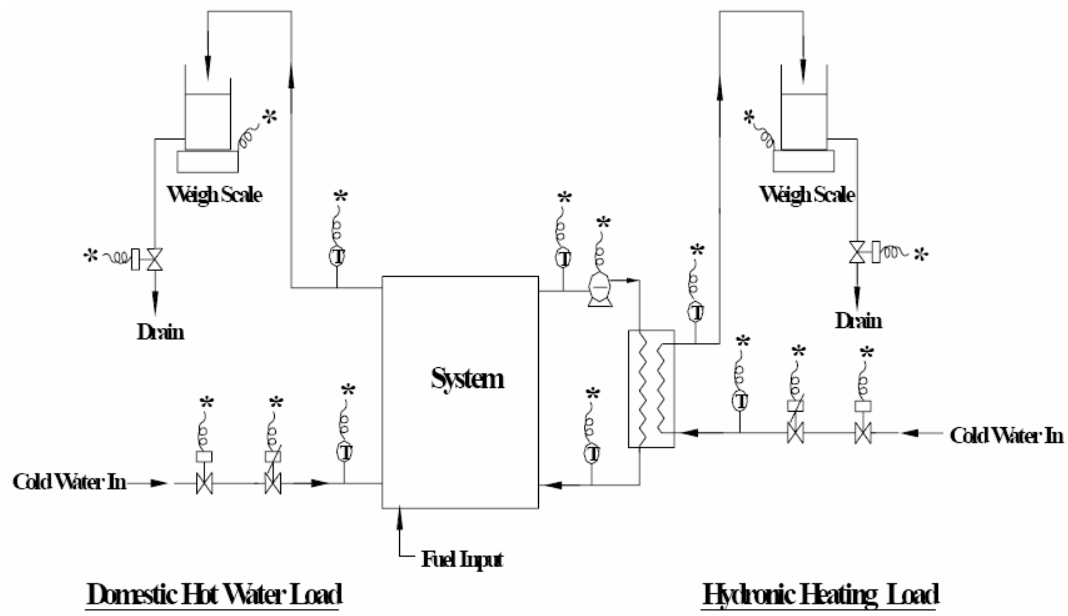


Figure 12 Brookhaven Test Loop

Boiler "jacket" loss, energy lost to the surroundings through the boiler outer insulation, has also been measured based on surface temperature measurements and defined in the ASHRAE Standard for heating boilers and has been adapted and applied to some of the units. This is useful in evaluating the impact of location of the system on heating costs and the sources of inefficiency which could be addressed.

Test heating oil was periodically analyzed for heating value and density at a commercial lab. For natural gas a gas chromatograph designed for online analysis of this fuel was installed. This provided an analysis of composition and, from this; heating value, density and Wobbe index are calculated.

Test results have demonstrated that the input/output method being developed by ASHRAE for commercial boilers can be applied to residential integrated appliances and that these results can be used to draw conclusions about energy use under a wide range of load and oversize scenarios. The test results further demonstrate the AFUE ratings on boilers and integrated boiler/DHW systems do not represent actual system performance. Based on this body of work, the new Brookhaven National Laboratory boiler/DHW system performance methodology was used to determine fuel usage.

Residential Heating System Comparison

The amount of fuel used by a heating system, and in-turn CO_2 emitted, is dependent upon the location, building annual heat and hot water demand, and system efficiency. In this section, an analysis of fuel use has been done primarily to illustrate the fuel use of new, upgraded systems relative to the older installed base of systems. As discussed above, the focus here is on integrated hydronic systems, i.e. hydronic heating systems where the boiler also provides domestic hot water either through a "tankless coil" inside of the boiler's heating water volume or a separate "indirect" domestic hot water tank treated like a separate boiler zone.

This comparison has been done only for one home type – a 2,500 ft^2 ranch home with a basement with typical "code" construction. The hourly heating load for this home in six different cities has been calculated using the Energy-10 modeling software[36]. Hourly heat demand has been exported to a separate file and then DHW demand has been added for each hour to determine the total hourly load on the integrated hydronic system for each hour of the year. The DHW load has been based on the assumption of 64.3 gallons per day[37] and a demand distribution based on field data[38].

Boiler and DHW System Results

The analysis for all cases has been done with two major variants – with and without domestic hot water. **Table 103** and **Table 104**, below, provide the results with the domestic hot water load included. **Table 105** and **Table 106** provide the same results of the analysis done for all systems in a heating only mode (domestic hot water load =0) and this would relate to an integrated system where there is a separate hot water heater (electric or fuel fired).

The systems included in **Table 103** through **Table 106** require some additional discussion.

- Systems 1 and 2 (oil and gas-fired respectively) represent the average oil and gas non-condensing boilers currently being sold in the market. This is not one specific system but rather has been estimated based on an analysis of sales data.

- Systems 3 and 4 (oil and gas-fired respectively) represent the best available systems on the market today. System 3 is a high efficiency, oil-fired system which uses the control strategy discussed above (thermal purge) in combination with a very well insulated indirect domestic hot water storage tank to achieve very low idle losses. System 4 is a similar case and represents a high efficiency gas system currently on the market.

- Systems 5 and 6 (oil and gas-fired respectively) represent systems using condensing boilers with radiant floor heating (low supply and return temperature), and much higher thermal efficiency is realized. Where included, the domestic hot water load would be served using an indirect tank. The boiler controls provide higher temperature water to the tank coil.

- Systems 7 and 8 (oil and gas-fired respectively) represent systems using condensing boilers with baseboard radiators (mostly not condensing). To achieve condensing the return water temperature

36 Energy-10 Software site, Sustainable Building Council, http://www.sbicouncil.org/displaycommon.cfm?an=1&subarticlenbr=112 June 13, 2008.

37 Method of Testing for Rating Residential Water Heaters, ASHRAE Standard 118.2-2006, American Soc. of Heating, Refrigeration, and Air-Conditioning Engineers, Inc., 2006.

38 HVAC Applications, American Soc. of Heating, Refrigeration, and Air-Conditioning Engineers, Inc, 2003.

from the system must be at least 10 degrees below the flue gas water vapor dewpoint. With oil, the dewpoint is about 120 F and with gas about 140 F. Baseboard radiators are generally designed for operation at about 165 F and return water temperatures are too high for condensing.

- Systems 9 and 10 (oil and gas-fired respectively) represent systems that just meet the current minimum AFUE efficiency standard. The thermal efficiency for these systems has been assumed to be the same as AFUE – 80 percent. The idle loss has been taken as 1.5 percent, a typical value for minimum efficiency systems based on the BNL tests.

- Systems 11 and 12 (oil and gas-fired respectively) represent future minimum efficiency systems. System 11 is the minimum efficiency oil boiler expected in 2015 and System 12 is the minimum efficiency gas boiler expected in 2015. The idle losses of these systems are taken as 1 percent and they could represent moderate quality systems with integrated tankless coils for hot water production.

- Systems 13 and 14 (oil and gas-fired respectively) represent the average oil and gas units currently operating in the field. The performance parameters for these have been estimated from the BNL study as well as from a methodology developed by the National Renewable Energy Laboratory[39]. These clearly represent systems with include tankless coils for hot water.

Table 103 and **Table 104** present the fuel use for 14 boiler/DHW configurations, note the odd numbers represent oil-fired equipment and the even numbers represent the natural gas-fired systems. **Table 103** includes DHW heating and **Table 105** is heating only. **Table 104** and **Table 106** present the same data but convert gallons of oil and 1,000 BTU of natural gas into million Btu (MMBtu) of fuel use.

Note that systems 1 through 8 were selected for further review with respect to their Greenhouse Gas Impact because they represent the logical construct for examining current practice and future potential for heating oil, ultra low sulfur diesel and biodiesel blends, as well as, natural gas and LNG. Comparison graphs of the eight systems using these fuels will be presented in the following chapter.

[39] Hendron, R. Building America Performance Analysis Procedures for Existing Homes, NREL/TP-550-38238, May 2006.

Table 103 Boiler Summary Results, *with domestic hot water* in gallons of heating oil and 1,000 ft^3 of natural gas

Boiler & DHW Comparison					Location					
System	Description	Thermal Eff. %	Idle Loss (%)	units	Baltimore, MD	Boston, MA	Madison, WI	New York, NY	Norfolk, VA	Seattle, WA
1	Average oil boiler currently sold	84	1	gal	739	866	1155	794	536	694
2	Average gas boiler currently sold	82	1	1000 ft^3	110	126.9	169.3	118.6	79.5	101.2
3	Current high efficiency oil boiler	86.5	0.15	gal	668	788	1050	697	476	639
4	Current high efficiency gas boiler	82	1	1000 ft^3	104.4	122.4	163.2	112.2	75.7	98.2
5	Condensing oil boiler with radiant floor	95	0.5	gal	627	737	983	662	450	595
6	Condensing gas boiler with radiant floor	95	0.5	1000 ft^3	86.5	101.8	135.6	91.4	62.1	82.1
7	Condensing oil boiler with baseboard	90	0.6	gal	667	784	1046	708	480	632
8	Condensing gas boiler with baseboard	87.5	0.6	1000 ft^3	94.7	111.3	148.4	100.4	68.1	89.7
9	NAECA min oil boiler today 80% AFUE	80	1.5	gal	807	943	1257	881	591	752
10	NAECA min gas boiler today 80% AFUE	80	1.5	1000 ft^3	111.4	130	173.5	121.5	81.5	103.7
11	2015 NAECA oil boiler min efficiency	83	1	gal	748	876	1168	803	542	703
12	2015 NAECA gas boiler min efficiency	82	1	1000 ft^3	104.4	122.4	163.2	112.2	75.7	98.2
13	Average oil boiler now in field	73	2	gal	920	1070	1427	1017	678	848
14	Average gas boiler now in field	73	2	1000 ft^3	126.9	147.6	197	140.3	93.6	117.1

Figure 13 presents the fuel energy use from **Table 103**. Comparing oil to gas boiler/DHW end-use performance of similar technologies (1 to 2, 2 to 3, etc.) a clear pattern emerges, in that systems 4 through 14 show natural gas to have slightly better performance than oil. However, systems 1 through 4 shows oil systems out performing natural gas systems. The reason for this phenomenon can be found in the water content of the two fuels. Oil contains less water than natural gas and therefore systems can operate in non-condensing modes at higher efficiencies (lower flue stack temperatures). Therefore, a non-condensing oil boiler can have a thermal efficiency in the 88 to even 90 percent range whereby a natural gas boiler can operate in non-condensing mode only up to 82 percent.

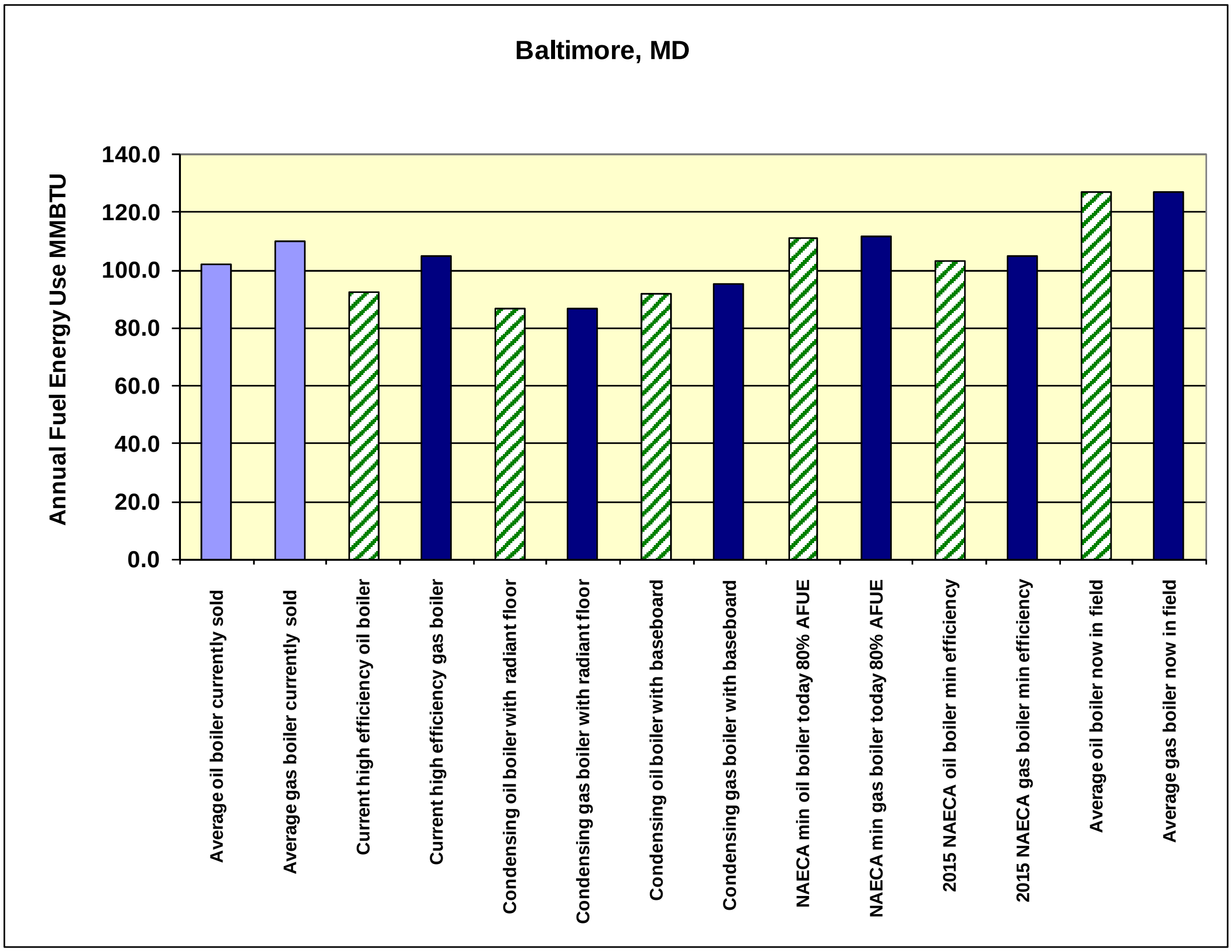


Figure 13 Baltimore Fuel Energy Use Boiler with DHW

Table 104 Boiler Summary Results, *with domestic hot water* in MMBTU of fuel used

Boiler & DHW Comparison				Location					
System	Description	Thermal Eff. %	Idle Loss (%)	Baltimore, MD	Boston, MA	Madison, WI	New York, NY	Norfolk, VA	Seattle, WA
1	Average oil boiler currently sold	84	1	102.0	119.5	159.4	109.6	74.0	95.8
2	Average gas boiler currently sold	82	1	110.0	126.9	169.3	118.6	79.5	101.2
3	Current high efficiency oil boiler	86.5	0.15	92.2	108.7	144.9	96.2	65.7	88.2
4	Current high efficiency gas boiler	82	1	104.4	122.4	163.2	112.2	75.7	98.2
5	Condensing oil boiler with radiant floor	95	0.5	86.5	101.7	135.7	91.4	62.1	82.1
6	Condensing gas boiler with radiant floor	95	0.5	86.5	101.8	135.6	91.4	62.1	82.1
7	Condensing oil boiler with baseboard	90	0.6	92.0	108.2	144.3	97.7	66.2	87.2
8	Condensing gas boiler with baseboard	87.5	0.6	94.7	111.3	148.4	100.4	68.1	89.7
9	NAECA min oil boiler today 80% AFUE	80	1.5	111.4	130.1	173.5	121.6	81.6	103.8
10	NAECA min gas boiler today 80% AFUE	80	1.5	111.4	130.0	173.5	121.5	81.5	103.7
11	2015 NAECA oil boiler min efficiency	83	1	103.2	120.9	161.2	110.8	74.8	97.0
12	2015 NAECA gas boiler min efficiency	82	1	104.4	122.4	163.2	112.2	75.7	98.2
13	Average oil boiler now in field	73	2	127.0	147.7	196.9	140.3	93.6	117.0
14	Average gas boiler now in field	73	2	126.9	147.6	197.0	140.3	93.6	117.1

Table 105 Summary Results, *heating only* in gallons of heating oil and 1,000 ft^3 of natural gas

Boiler without DHW Comparison					Location					
System	Description	Thermal Eff. %	Idle Loss (%)	units	Baltimore, MD	Boston, MA	Madison, WI	New York, NY	Norfolk, VA	Seattle, WA
1	Average oil boiler currently sold	84	1	gal	612	739	1028	667	409	567
2	Average gas boiler currently sold	82	1	1000 ft^3	92	109.1	151.4	100.7	61.7	83.3
3	Current high efficiency oil boiler	86.5	0.15	gal	543	664	926	573	352	515
4	Current high efficiency gas boiler	82	1	1000 ft^3	86.5	104.5	145.3	94.3	57.8	80.2
5	Condensing oil boiler with radiant floor	95	0.5	gal	514	625	870	550	337	482
6	Condensing gas boiler with radiant floor	95	0.5	1000 ft^3	70.9	86.2	120.1	75.9	46.6	66.6
7	Condensing oil boiler with baseboard	90	0.6	gal	548	665	927	589	361	513
8	Condensing gas boiler with baseboard	87.5	0.6	1000 ft^3	77.8	94.5	131.5	83.6	51.3	72.8
9	NAECA min oil boiler today 80% AFUE	80	1.5	gal	675	810	1125	748	458	619
10	NAECA min gas boiler today 80% AFUE	80	1.5	1000 ft^3	93.1	111	155.2	103.2	63.2	85.4
11	2015 NAECA oil boiler min efficiency	83	1	gal	619	748	1040	675	414	574
12	2015 NAECA gas boiler min efficiency	82	1	1000 ft^3	86.5	104.5	145.3	94.3	57.8	80.2
13	Average oil boiler now in field	73	2	gal	775	925	1283	872	533	704
14	Average gas boiler now in field	73	2	1000 ft^3	106.9	127.7	177	120.3	73.6	97.1

Table 106 Boiler Summary Results, *heating on*ly in MMBTU of fuel used

Boiler without DHW Comparison				Location					
System	Description	Thermal Eff. %	Idle Loss (%)	Baltimore, MD	Boston, MA	Madison, WI	New York, NY	Norfolk, VA	Seattle, WA
1	Average oil boiler currently sold	84	1	84.5	102.0	141.9	92.0	56.4	78.2
2	Average gas boiler currently sold	82	1	92.0	109.1	151.4	100.7	61.7	83.3
3	Current high efficiency oil boiler	86.5	0.15	74.9	91.6	127.8	79.1	48.6	71.1
4	Current high efficiency gas boiler	82	1	86.5	104.5	145.3	94.3	57.8	80.2
5	Condensing oil boiler with radiant floor	95	0.5	70.9	86.3	120.1	75.9	46.5	66.5
6	Condensing gas boiler with radiant floor	95	0.5	70.9	86.2	120.1	75.9	46.6	66.6
7	Condensing oil boiler with baseboard	90	0.6	75.6	91.8	127.9	81.3	49.8	70.8
8	Condensing gas boiler with baseboard	87.5	0.6	77.8	94.5	131.5	83.6	51.3	72.8
9	NAECA min oil boiler today 80% AFUE	80	1.5	93.2	111.8	155.3	103.2	63.2	85.4
10	NAECA min gas boiler today 80% AFUE	80	1.5	93.1	111.0	155.2	103.2	63.2	85.4
11	2015 NAECA oil boiler min efficiency	83	1	85.4	103.2	143.5	93.2	57.1	79.2
12	2015 NAECA gas boiler min efficiency	82	1	86.5	104.5	145.3	94.3	57.8	80.2
13	Average oil boiler now in field	73	2	107.0	127.7	177.1	120.3	73.6	97.2
14	Average gas boiler now in field	73	2	106.9	127.7	177.0	120.3	73.6	97.1

6
OVERALL ENERGY AND GHG EMISSIONS COMPARISONS

Introduction

This section presents a comparison of total resource energy use and GHG emissions for natural gas and heating oil considering both the fuel cycle analyses and ultimate end use heating system efficiency. The results are presented for the five market demand regions. Each demand region discussion contains comparative graphs for 2006 and 2020 of the fuel cycle (up to the burner tip) GHG emissions intensity of each fuel type (delivered natural gas from the composite supply resources for each demand region, marginal LNG for certain regions, heating oil, and biofuels (a 5 percent blend and 100 percent biofuel in 2006 (B5 and B100), and a 20 percent blend and 100 percent biofuel in 2020 (B20 and B100)). This section also includes an analysis of total annual resource energy requirements and annual full fuel cycle GHG emissions to provide space heating and hot water energy services to a typical house utilizing a number of equipment/fuel type combinations. Graphs compare the total annual natural gas, heating oil and biofuel blend resource energy requirements and fuel cycle GHG emissions for four combinations of end use technologies to provide home space heating asnd domestic hot water services:

1. average efficiency boilers currently being sold
2. high efficiency non-condensing boilers
3. condensing boilers for retrofit and new homes using baseboard radiation
4. condensing boilers applied to new homes using high efficiency radiant floor heating systems

Energy and GHG Emissions Comparison by Demand Region

Each demand region section contains three sets of comparisons:

- Fuel Cycle GHG Emissions – The fuel cycle GHG emissions comparison graphs show the amount of CO_2 equivalent emissions that is associated with delivering each MMBtu of the selected fuels **to the burner-tip**. These comparisons are presented for both 2006 and 2020. Changes in emissions intensity that occur over this time frame reflect changes in energy use and emissions for the various fuel cycle stages for each fuel, as well as changes in the supply base (e.g., changes to both domestic supply areas and LNG imports for natural gas) for each demand region. As an example, in 2020, three demand regions (New England, NY/NJ/PA, and VA/MD) will be utilizing a much higher portion of LNG for their supply base, which has a higher fuel cycle GHG emissions intensity than North American natural gas. Alternatively, in 2020, the analysis assumed that 20 percent biofuel blends (B20) could be used in standard heating systems.

- Annual Resource Energy Use of Residential Heating Systems – Energy comparison graphs show the projected total annual resource energy consumption (in MMBtu) for average, high efficiency non-condensing, and high efficiency condensing heating systems fueled by heating oil and natural gas based on modeled energy consumption of a 2,500 square foot house for each region. Estimates are given for both 2006 and 2020; B5 biofuel is included in 2006 and 20 biofuel in the 2020 comparison. These graphs compare the amount of total resource energy required to provide the same amount of heating services, supplied by the four different boiler types, for a standard home in each region. The comparison includes not only the fuel cycle efficiency of each fuel, but also the efficiency of the heating equipment at the ultimate point of use.

- Annual GHG Emissions of Residential Heating System – Similarly, the emissions comparison graphs show projected total fuel cycle GHG emissions in pounds of CO_2 equivalent per year that are associated with providing the heating and hot water energy services for each type of heating system and fuel combination. This comparison includes not only the fuel cycle GHG emissions of each fuel up to the burner tip, but also reflects the efficiency of the heating equipment at the ultimate point of use.

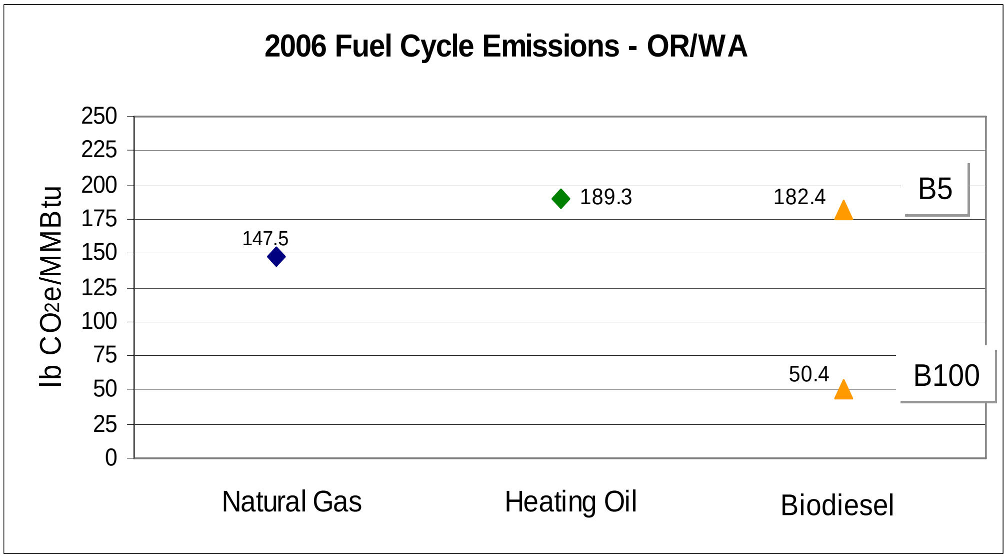
Oregon/Washington

As detailed in Section 2, the bulk of 2006 heating oil supplies to this region originate in refineries in Washington state using crude oil from Alaska and Canada. This supply mix is not projected to change significantly in 2020. Similarly, **Table 107** shows that the natural gas supply mix for this region is also expected to be relatively stable over the timeframe of the analysis. LNG is not expected to be a major supply source in this region in 2020.

Table 107 Natural Gas Supply Mix into Oregon/Washington

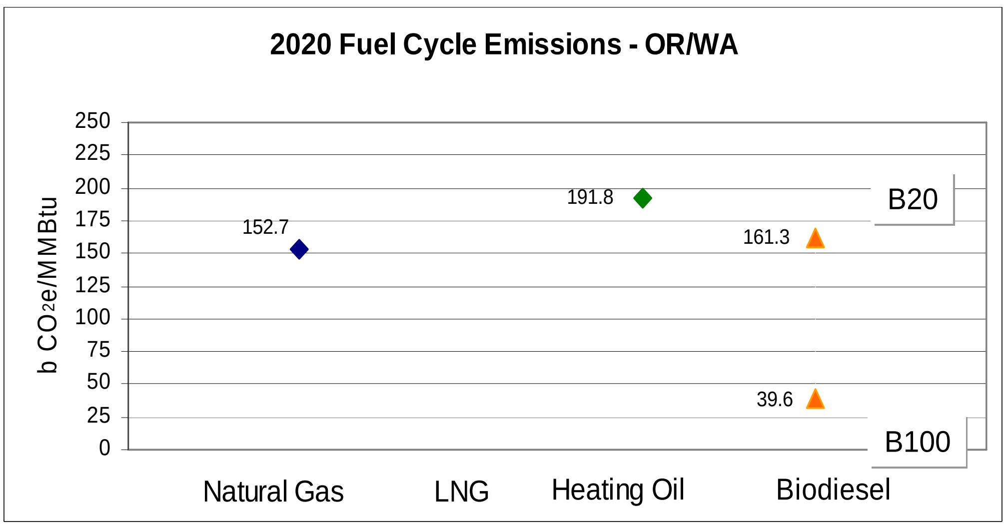
	2006		2020	
Supply Source	Supply Share	Pipeline Mileage	Supply Share	Pipeline Mileage
Western Canada	84 %	1,026 miles	81 %	1,026 miles
Rocky Mountains	16 %	831 miles	19 %	831 miles
	100 %		100 %	

Figure 14 and **Figure 15** show the resulting final fuel cycle GHG emissions in pounds of CO_2 equivalent per MMBtu of fuel delivered (not including end use equipment efficiency) for each fuel type in 2006 and 2020. The changes in GHG emissions intensities from 2006 to 2020 for both natural gas and oil are relatively minor in this region, reflecting the relative stability of the supply mix. Natural gas has about 42 lbs CO_2e/MMBtu less GHG emissions than heating oil in 2006 and about 39 pounds less in 2020. Availability of B20 in 2020 narrows that difference to less than 10 lbs CO_2e/MMBtu.



* CO_2 equivalent based on 100 year GHG warming potential

Figure 14 2006 Fuel Cycle Emissions Comparison for Oregon/Washington



* CO_2 equivalent based on 100 year GHG warming potential

Figure 15 2020 Fuel Cycle Emissions Comparison for Oregon/Washington

Figure 16 and **Figure 17** illustrate the total annual energy requirements to provide heating and hot water services to the modeled 2,500 square foot house in the Oregon/Washington region (including energy use along the fuel cycle and end use equipment efficiency) for average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. Total energy use to provide the required heating services is slightly higher for natural gas for the average and high efficiency, non-condensing systems reflecting the higher end use efficiencies of the oil equipment. The total energy use is lower for natural gas for the high efficiency condensing units. The relative position of the two fuels is essentially unchanged between 2006 and 2020. Biofuel with a 5 percent blend in 2006 and a 20 percent blend in 2020 have higher total energy useage than both conventional heating oil and natural gas because of the energy intensity of the production process; however, as shown in following graphs, biofuel blends can have a lower GHG emissions impact than conventional heating oil.

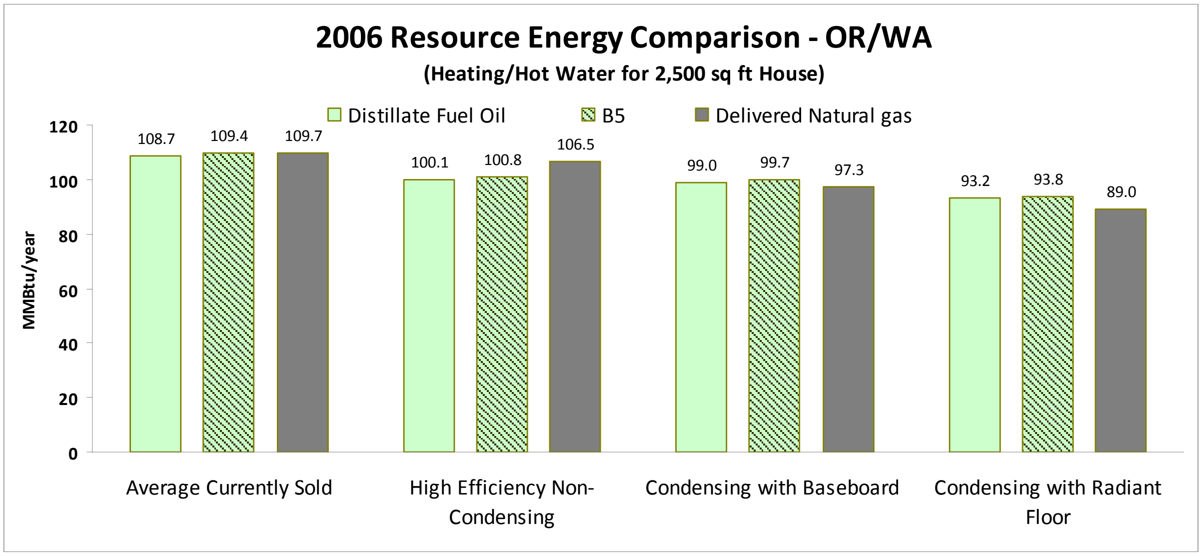


Figure 16 Heating System Energy Comparison for Oregon/Washington in 2006

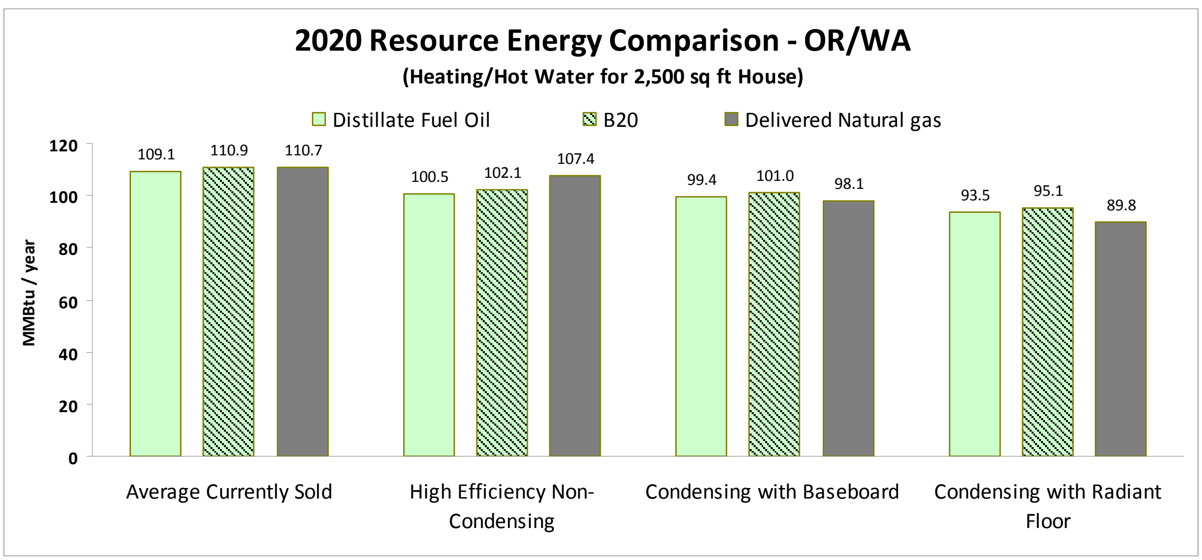


Figure 17 Heating System Energy Comparison for Oregon/Washington in 2020

Figure 18 and **Figure 19** show the total annual fuel cycle GHG emissions based on the total annual energy consumption for the average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. Heating oil produces anywhere from 15 to 28 percent more GHG emissions than natural gas on an annual basis in 2006. The minimal changes in total energy use between 2006 and 2020 for each of the fuels are reflected in the annual GHG emissions. Heating oil produces from 13 to 26 percent more GHG emissions than natural gas in 2020. The GHG emissions of B20 are slightly less than that of natural gas for the average and high efficiency, non-condensing units, and approach natural gas for the high efficiency, non-condensing systems.

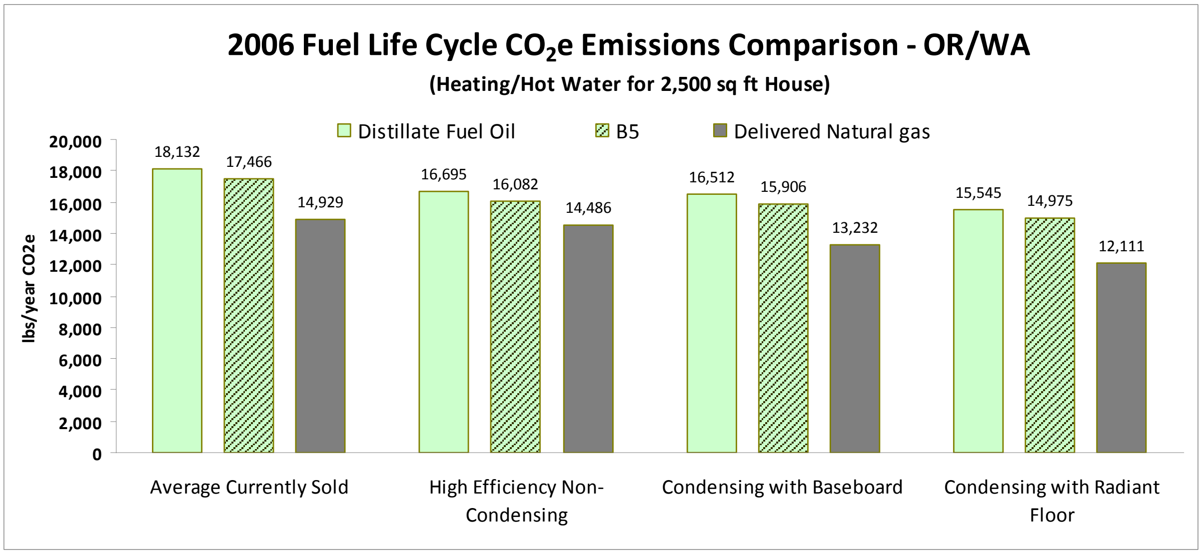


Figure 18 Heating System Emissions Comparison for Oregon/Washington in 2006

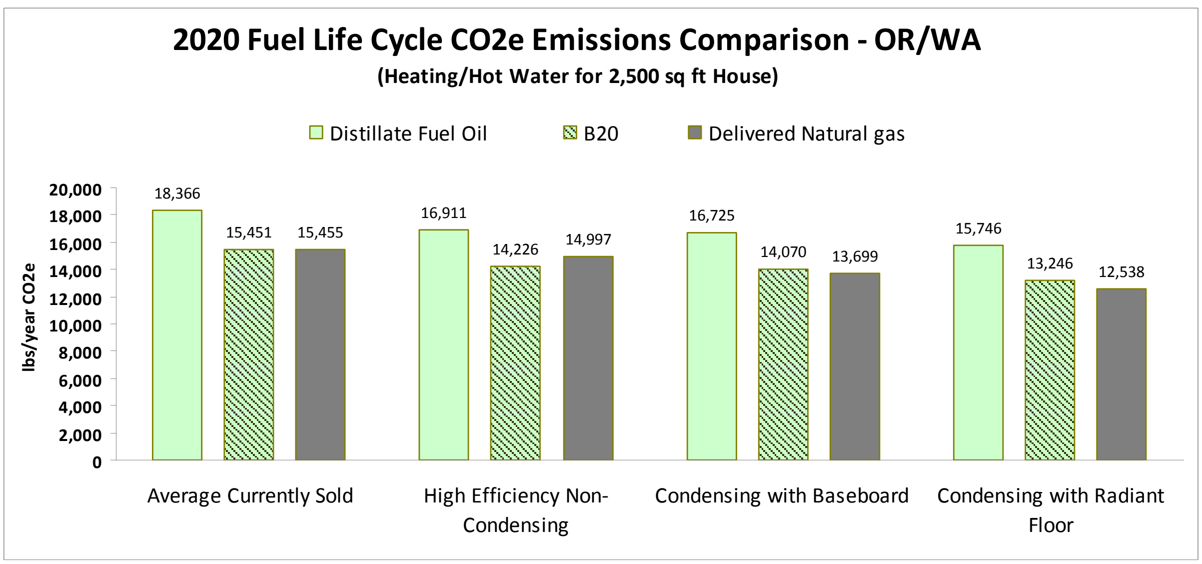


Figure 19 Heating System Emissions Comparison for Oregon/Washington in 2020

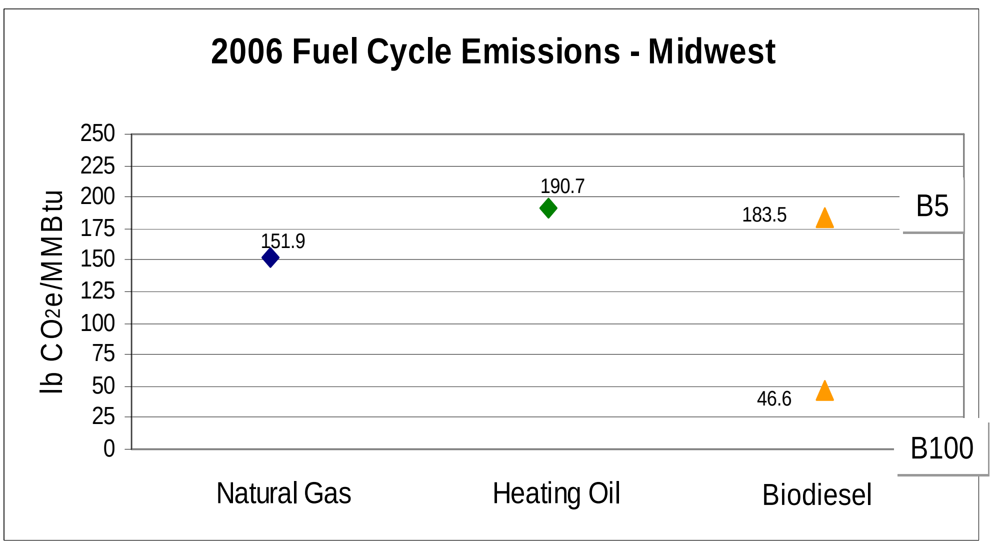
Upper Midwest

Similarly to the Oregon/Washington demand region, the oil and natural gas supply mix to the upper Midwest is also relatively stable over the time period of the analysis. **Table 108** shows that the most significant change in the natural gas supply mix for this region is a decrease in supplies from the relatively close mid-continent supply region and an increase in supply from the more distant Gulf Coast.

Table 108 Natural Gas Supply Mix into the Upper Midwest

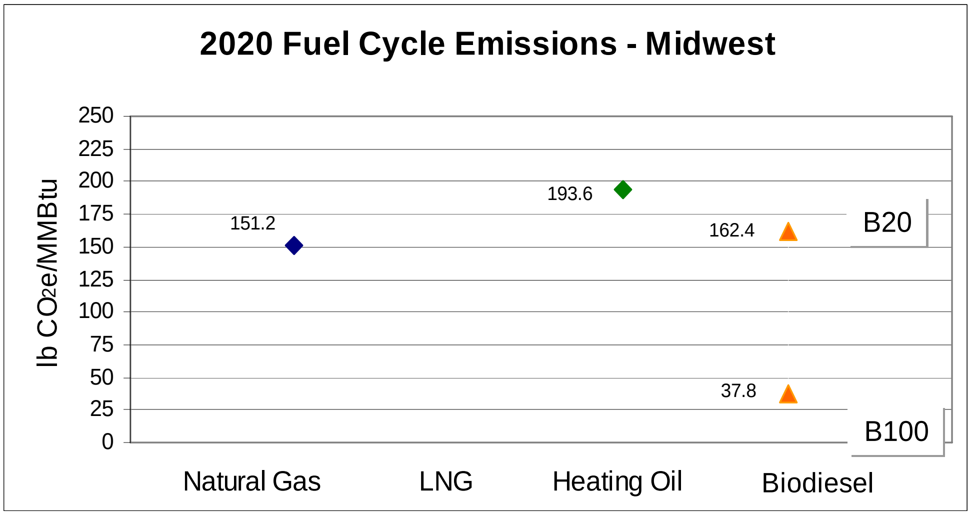
	2006		2020	
Supply Source	Supply Share	Pipeline Mileage	Supply Share	Pipeline Mileage
Western Canada	59 %	1,452 miles	56 %	1,452 miles
Rocky Mountains	9 %	1,232 miles	9 %	1,232 miles
Midcontinent	26 %	700 miles	14 %	700 miles
Gulf Coast	7%	1,099 miles	21 %	1,099 miles
	100 %		100 %	

Figure 20 and **Figure 21** show the resulting fuel cycle GHG emissions in pounds of CO_2 equivalent per MMBtu of fuel delivered (not including end use equipment efficiency) for each fuel type in 2006 and 2020 in the Midwest region. The changes in GHG emissions intensities from 2006 to 2020 for both natural gas and oil are relatively minor in this region, reflecting the relative stability of the supply mix. Natural gas has about 40 lbs CO_2e/MMBtu less GHG emissions than heating oil in both 2006 and 2020. Availability of B20 in 2020 narrows that difference to less than 10 lbs CO_2e/MMBtu. LNG is not expected to be a major supply source in the Midwest in 2020.



* CO_2 equivalent based on 100 year GHG warming potential

Figure 20 2006 Fuel Cycle Emissions Comparison for the Upper Midwest



* CO_2 equivalent based on 100 year GHG warming potential

Figure 21 2020 Fuel Cycle Emissions Comparison for the Upper Midwest

Figure 22 and **Figure 23** illustrate the total annual resource energy requirements to provide heating and hot water services to the modeled 2,500 square foot house in the Midwest region (including energy use along the fuel cycle and end use equipment efficiency) for average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. Total resource energy use to provide the required heating services is slightly lower for natural gas for the high efficiency condensing units in 2006 and 2020. Total resource energy use for heating oil is slightly lower for the average units currently in the market and for the high efficiency, non-condensing units reflecting the higher end-use efficiency of oil equipment. The relative position of the two fuels remains unchanged in 2020, with both experiencing slight increases in annual energy requirements. Again, biofuel blends have higher total energy use than both conventional heating oil and natural gas because of the energy intensity of the production process, however as shown in following graphs they have a lower emissions impact.

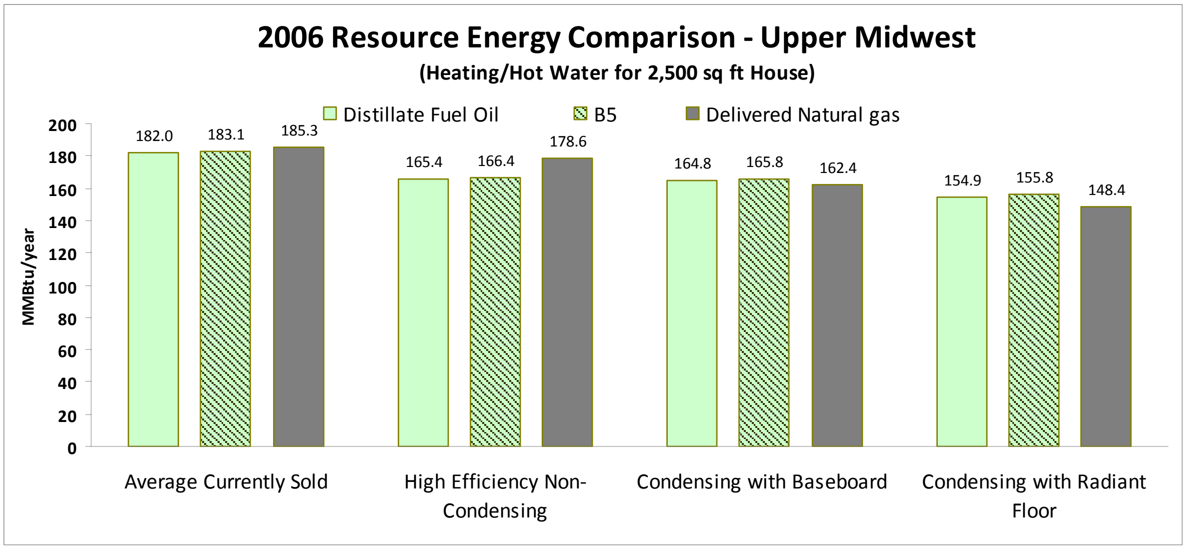


Figure 22 Heating System Energy Comparison for the Upper Midwest in 2006

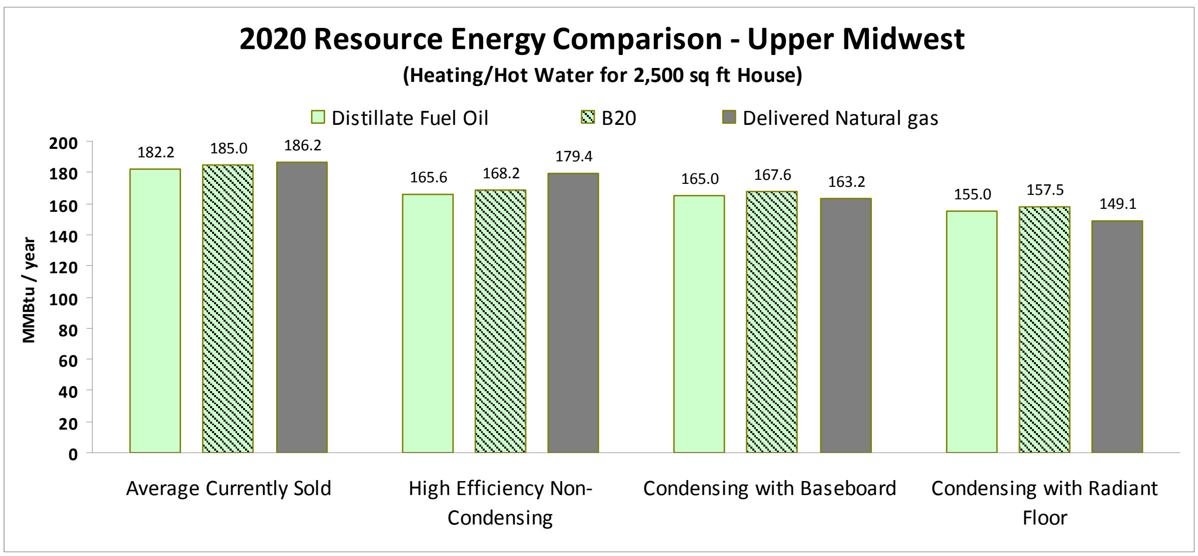


Figure 23 Heating System Energy Comparison for the Upper Midwest in 2020

Figure 24 and **Figure 25** show the resulting annual full fuel cycle GHG emissions based on the total annual energy consumption for the average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. Heating oil produces anywhere from 11 to 26 percent more GHG emissions than natural gas on an annual basis in 2006. Both heating oil and natural gas increase their GHG emissions marginally over the 2006 to 2020 time period, with little change in their relative position. The GHG emissions of B20 approach that of natural gas for the high efficiency condensing units, and are less than natural gas for the average and high efficiency, non-condensing system.

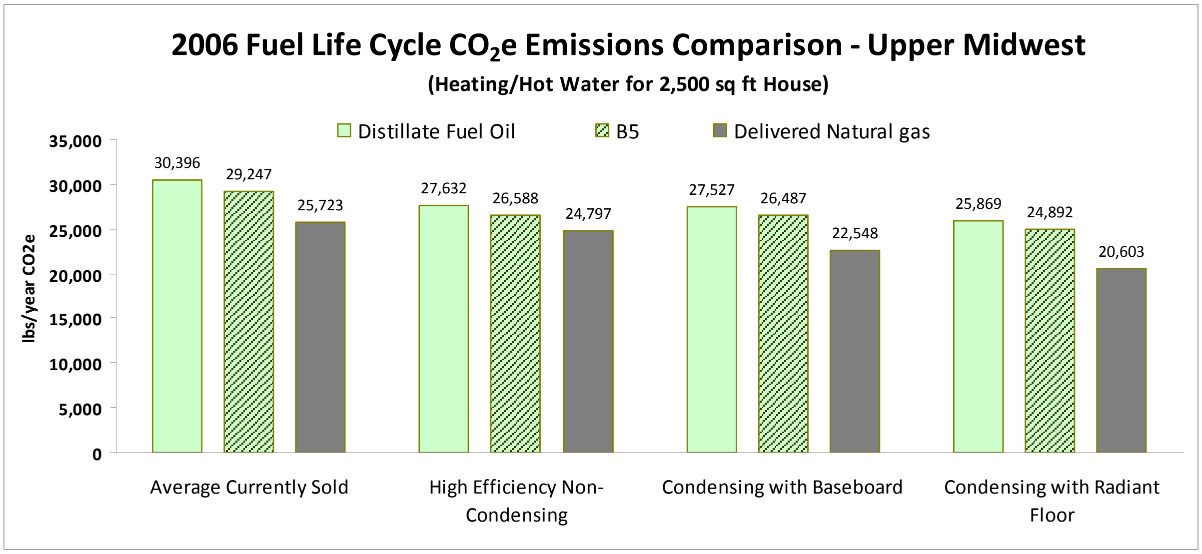


Figure 24 Heating System Emissions Comparison for the Upper Midwest in 2006

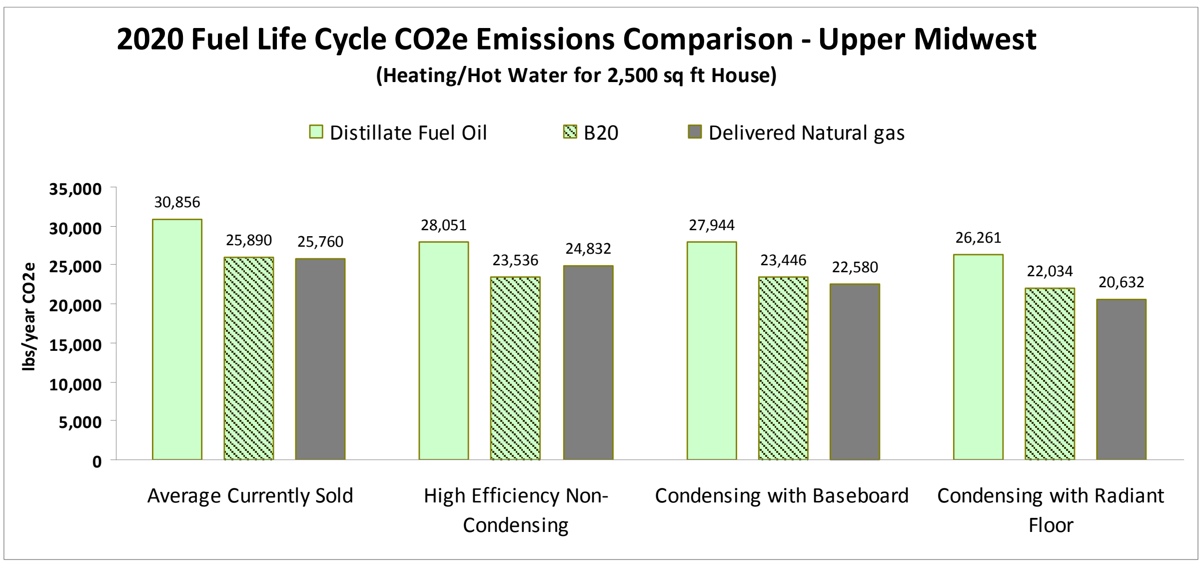


Figure 25 Heating System Emissions Comparison for the Upper Midwest in 2020

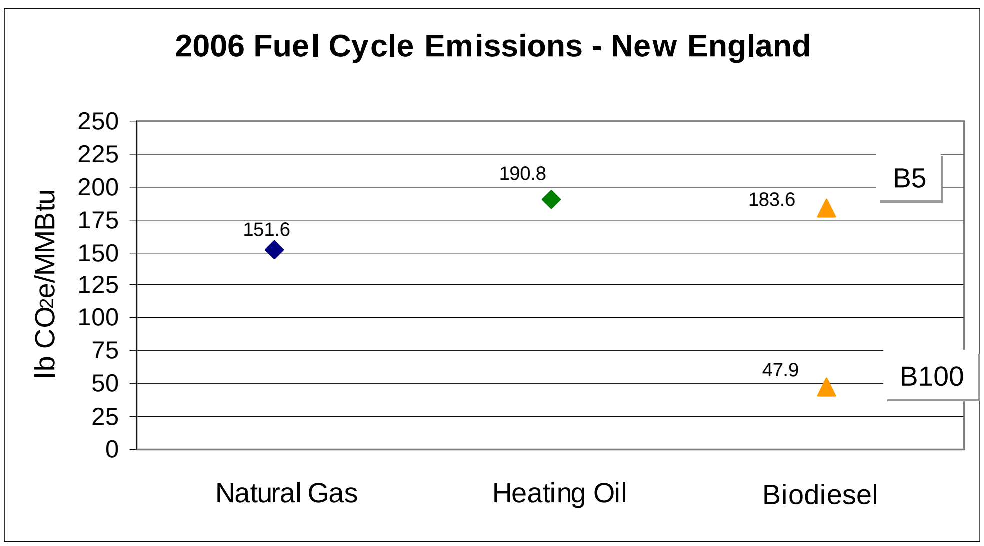
New England

New England is projected to experience significant changes in its natural gas supply mix over the time period of the analysis. As shown in **Table 109,** the region will see a significant decrease in gas from Western Canada and the Gulf Coast, both distant regions from New England, and increases in gas from Eastern Canada and from LNG shipments into terminals in New England and Canada.

Table 109 Natural Gas Supply Mix into New England

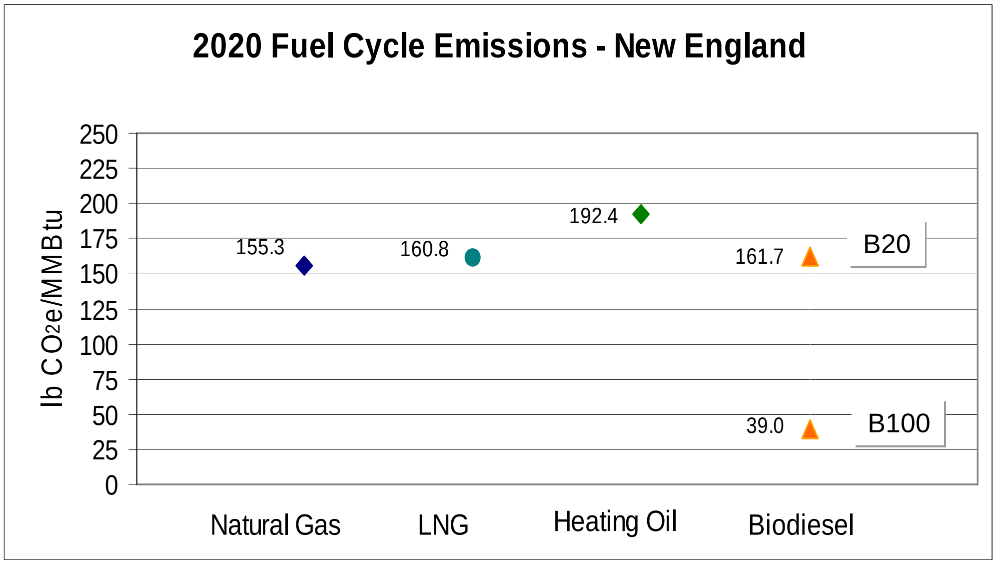
	2006		2020	
Supply Source	Supply Share	Pipeline Mileage	Supply Share	Pipeline Mileage
Eastern Canada	6 %	670 miles	12 %	670 miles
Western Canada	39 %	2,349 miles	12 %	2,349 miles
Gulf Coast	33 %	1,665 miles	21 %	1,665 miles
New England LNG	21%	490 miles	37 %	490 miles
Canadian Maritimes LNG	1 %	490 miles	17 %	490 miles
	100 %		100 %	

Figure 26 and **Figure 27** show the resulting final fuel cycle GHG emissions in pounds of CO_2 equivalent per MMBtu of fuel delivered (not including end use equipment efficiency) for each fuel type in 2006 and 2020. Natural gas delivered to this region has about 39 lbs CO_2e/MMBtu less GHG emissions than heating oil in 2006. The greater reliance on LNG in 2020 decreases this difference to 37 lbs CO_2e/MMBtu. LNG is included separately in Figure 27 to illustrate the GHG emissions intensity of this marginal supply option for this region. B20 is only about 6 lbs CO_2e/MMBtu higher in GHG emissions than delivered natural gas in 2020, and on a par with LNG imports into the region.



* CO_2 equivalent based on 100 year GHG warming potential

Figure 26 2006 Fuel Cycle Emissions Comparison for New England



* CO_2 equivalent based on 100 year GHG warming potential

Figure 27 2020 Fuel Cycle Emissions Comparison for New England

Figure 28 and **Figure 29** illustrate the total annual resource energy requirements to provide heating and hot water services to the modeled 2,500 square foot house in the New England region (including energy use along the fuel cycle and end use equipment efficiency) for average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. Total energy requirements to provide the annual heating services is higher for natural gas for both the average and high efficiency, non-condensing units in 2006, reflecting the supply mix for natural gas to this region and the transmission distances for the large percentage of gas coming from Western Canada and the Gulf Coast. Total energy use for the two fuels is approximately equal for the high efficiency, condensing units. The differences in total energy between the two fuels further increases in 2020, with natural gas experiencing larger increases in energy from 2006 to 2020 reflecting the higher energy intensity of LNG which represents 54 percent of the region's gas supply in 2020. Marginal LNG and delivered natural gas have higher total energy use compared to B20 for all units in 2020.

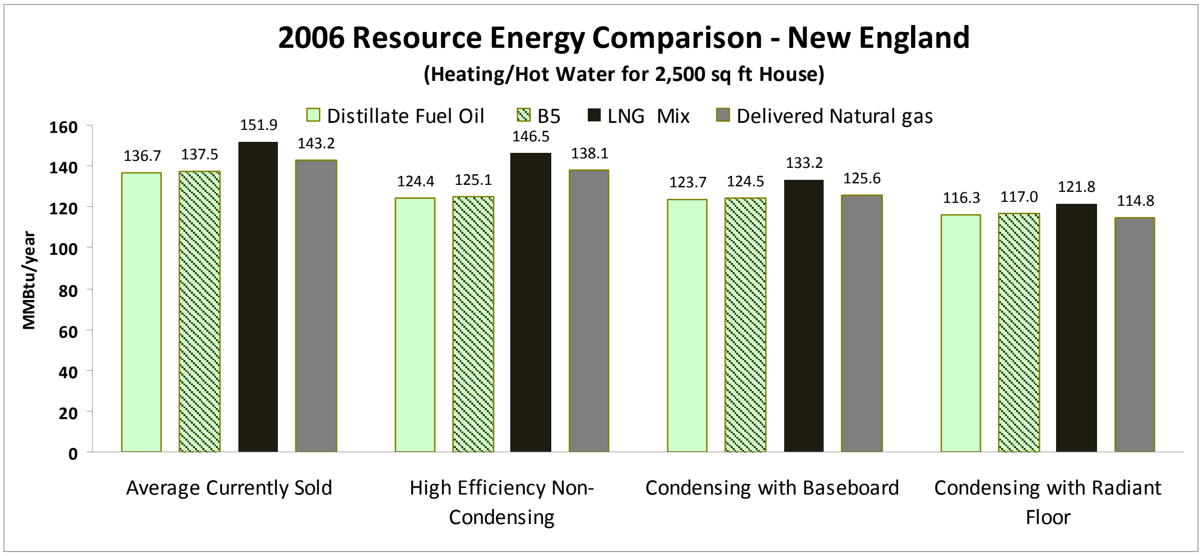


Figure 28 Heating System Energy Comparison for New England in 2006

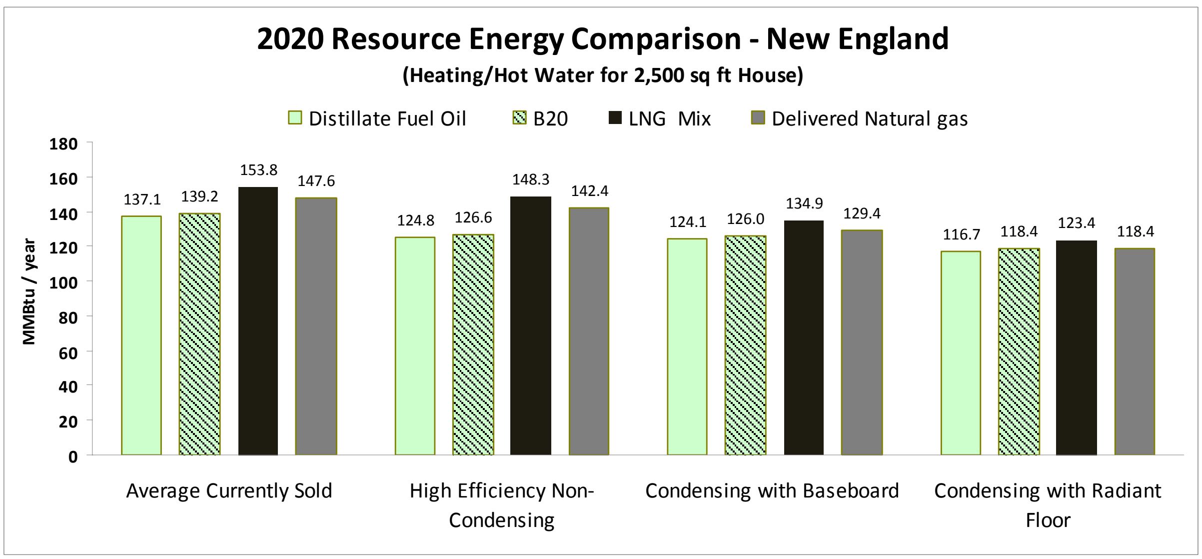


Figure 29 Heating System Energy Comparison for New England in 2020

Figure 30 and **Figure 31** show the resulting annual full fuel cycle GHG emissions based on the total annual energy consumption for the average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. Even though the previous graphs show that annual natural gas resource energy use for heating can be 10 percent higher than that of oil in this region, heating oil produces anywhere from 11 to 26 percent more GHG emissions than natural gas on an annual basis in 2006. The relative position of oil improves slightly in 2020. However, in 2020 B20 has lower emissions than delivered natural gas for both average and high efficiency, non-condensing systems.

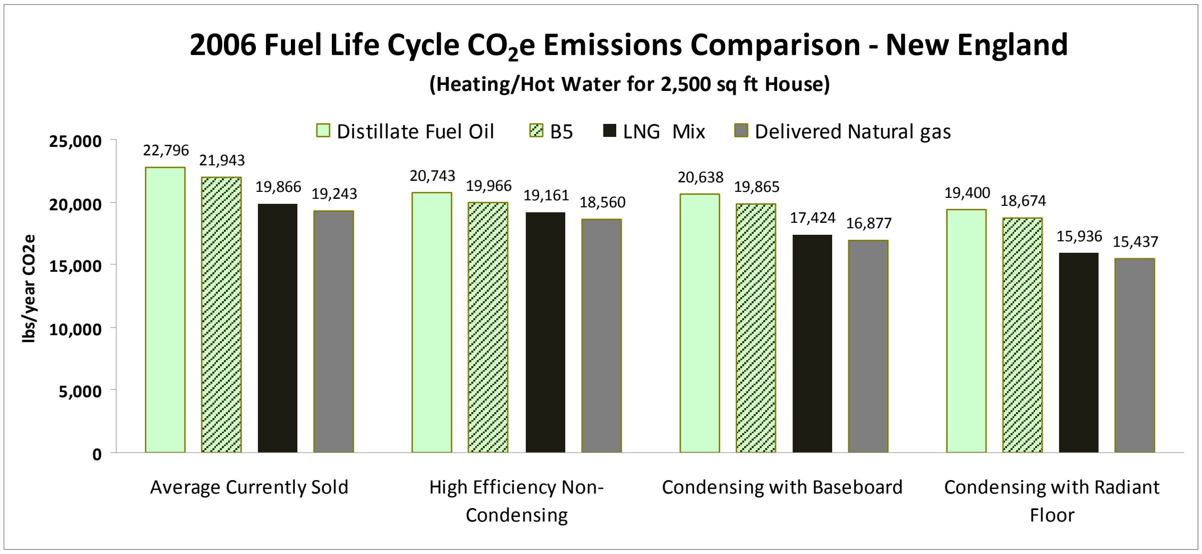


Figure 30 Heating System Emissions Comparison for New England in 2006

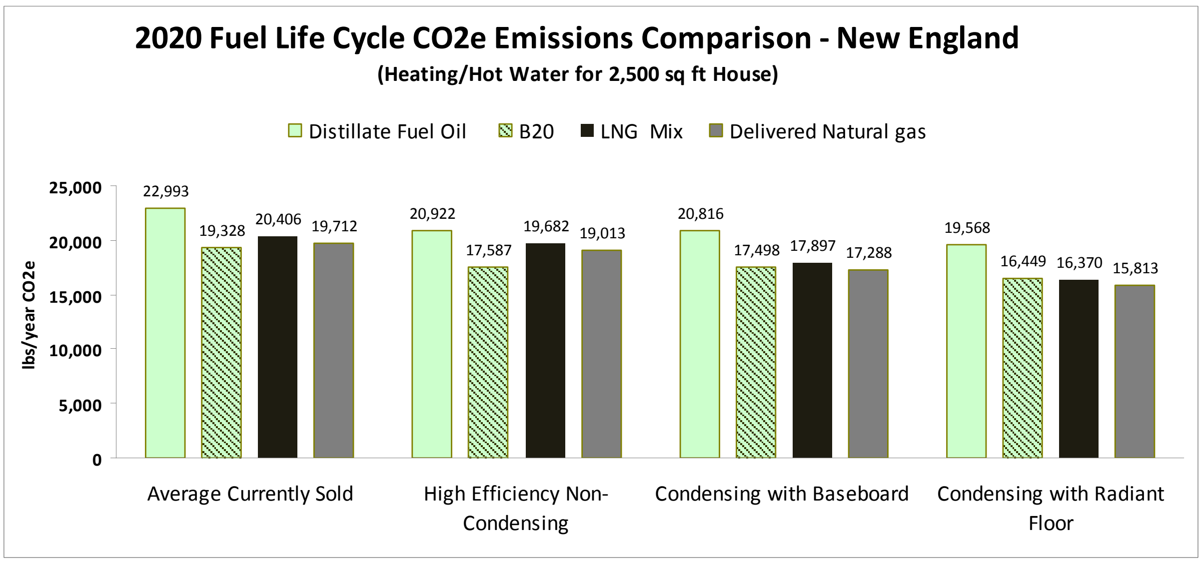


Figure 31 Heating System Emissions Comparison for New England in 2020

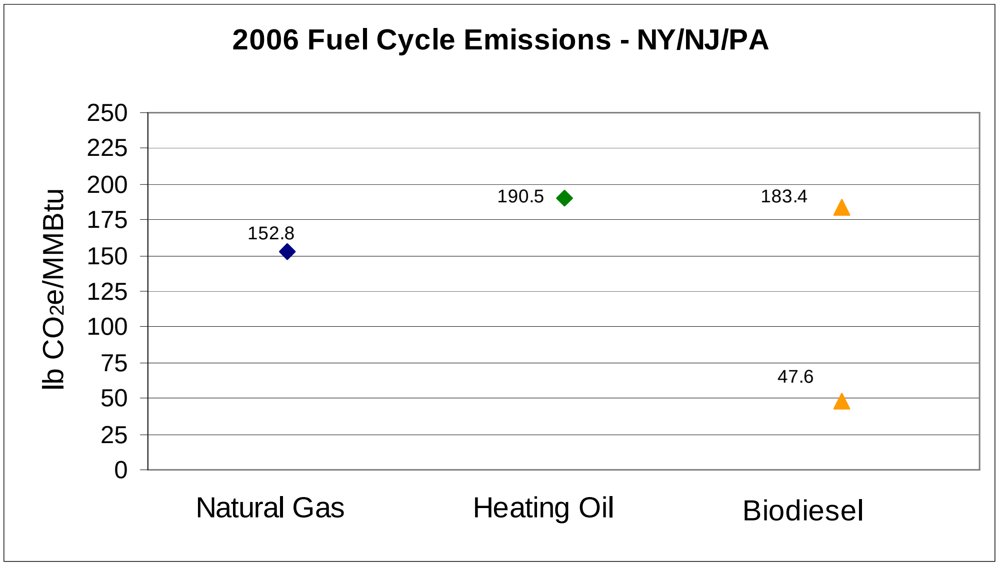
New York/New Jersey/Pennsylvania

The New York/New Jersey/Pennsylvania market region is projected to experience significant changes in its natural gas supply mix over the time period of the analysis. As shown in **Table 110,** the region will see a significant decrease in gas from Western Canada and the conventional Gulf Coast supplies, and increases in gas from the Rocky Mountains, Midcontinent and the Southwest, and from Gulf Coast LNG and from LNG shipments into regional terminals.

Table 110 Natural Gas Supply Mix into New York/New Jersey/Pennsylvania

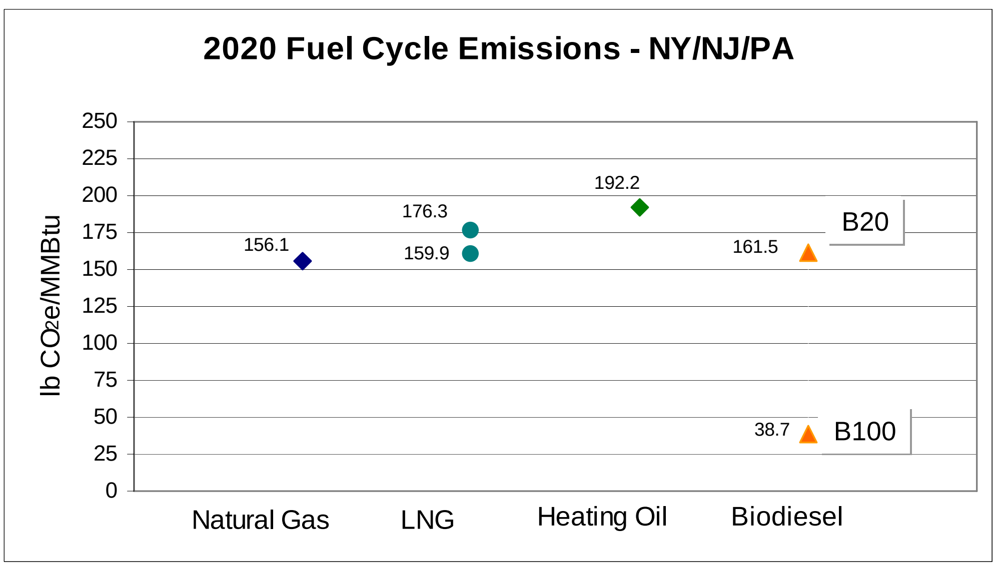
	2006		2020	
Supply Source	Supply Share	Pipeline Mileage	Supply Share	Pipeline Mileage
Western Canada	20 %	1,950 miles	7 %	1,950 miles
Rocky Mountains	2 %	1,990 miles	7 %	1,990 miles
Southwest	27 %	1,265 miles	32 %	1,265 miles
MidContinent	5%	1,800 miles	10 %	1,800 miles
Gulf Coast	42 %	1,300 miles	16 %	1,300 miles
East Coast LNG	3 %	400 miles	7 %	400 miles
Gulf Coast LNG	2 %	1,265 miles	22 %	1,265 miles
Total Supply	100 %		100 %	

Figure 32 and **Figure 33** show the fuel cycle GHG emissions in pounds of CO_2 equivalent per MMBtu of fuel delivered (not including end use equipment efficiency) for each fuel type in 2006 and 2020. Natural gas delivered to this region has about 38 lbs CO_2e/MMBtu less GHG emissions than heating oil in 2006. The greater reliance on LNG in 2020 decreases this difference to 36 lbs CO_2e/MMBtu. LNG is included separately in **Figure 33** to illustrate the GHG emissions intensity of this marginal supply option (a range is provided illustrating the delivered emissions intensity difference between Gulf Coast LNG which must be transported to the region by pipeline, and LNG delivered to local terminals, which has a smaller pipeline transportation component). B20 is about 5 lbs CO_2e/MMBtu higher in GHG emissions than delivered natural gas in 2020; B20 is only about 1.6 lbs CO_2e/MMBtu higher in GHG emissions than East Coast LNG supplies, and 14.8 lbs CO_2e/MMBtu less than Gulf Coast LNG.



* CO_2 equivalent based on 100 year GHG warming potential

Figure 32 2006 Fuel Cycle Emissions Comparison for New York/ New Jersey/ Pennsylvania



* CO_2 equivalent based on 100 year GHG warming potential

Figure 33 2020 Fuel Cycle Emissions Comparison for New York/ New Jersey/ Pennsylvania

Figure 34 and **Figure 35** illustrate the total annual resource energy requirements to provide heating and hot water services to the modeled 2,500 square foot house in the NY/NJ/PA region (including energy use along the fuel cycle and end use equipment efficiency) for the average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. Total resource energy required to provide the annual heating load is significantly higher for natural gas for both the average and high efficiency non-condensing units in 2006, reflecting the transmission distances for the large percentage of gas coming from Western Canada and the Gulf Coast. The gap between the two fuels increases in 2020, with natural gas experiencing larger increases in the total energy required to meet the heating loads, reflecting the shifts in North American supply sources into this region and the higher energy intensity of LNG which represents 29 percent of the region's gas supply in 2020. Natural gas also has a higher total energy use than B20 for the average and high efficiency non-condensing units in 2020.

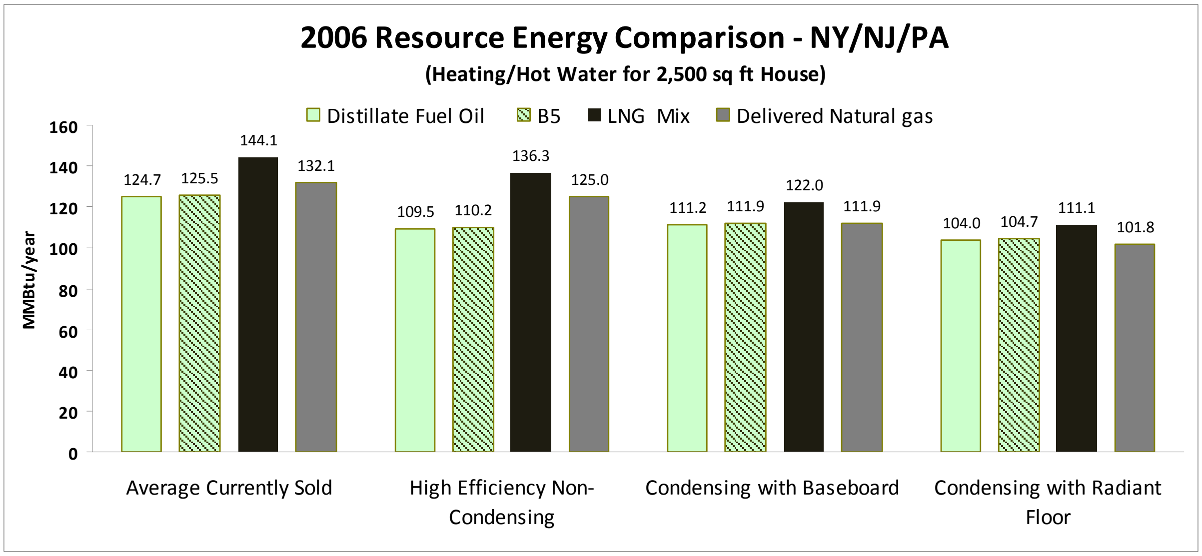


Figure 34 Heating System Energy Comparison for New York/New Jersey/Pennsylvania in 2006

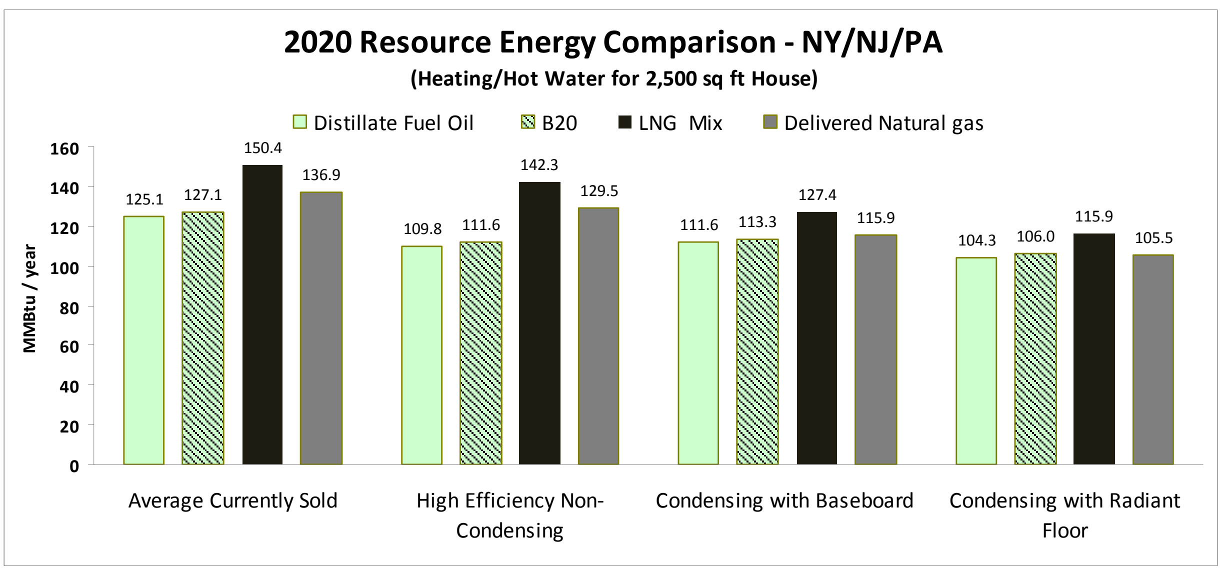


Figure 35 Heating System Energy Comparison for New York/New Jersey/Pennsylvania in 2020

Figure 36 and **Figure 37** show the resulting annual full fuel cycle GHG emissions based on the total annual energy consumption for the average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. As with New England, even though the energy consumption is higher for natural gas heating systems the annual GHG emissions are still lower due to the fuel characteristics. Heating oil produces anywhere from 6 to 24 percent more GHG emissions than natural gas on an annual basis in 2006. The relative position of oil improves slightly in 2020. Again, as in New England, B20 has lower emissions than delivered natural gas for in 2020 both average and high efficiency, non-condensing systems, and lower emissions than marginal LNG for all heating units.

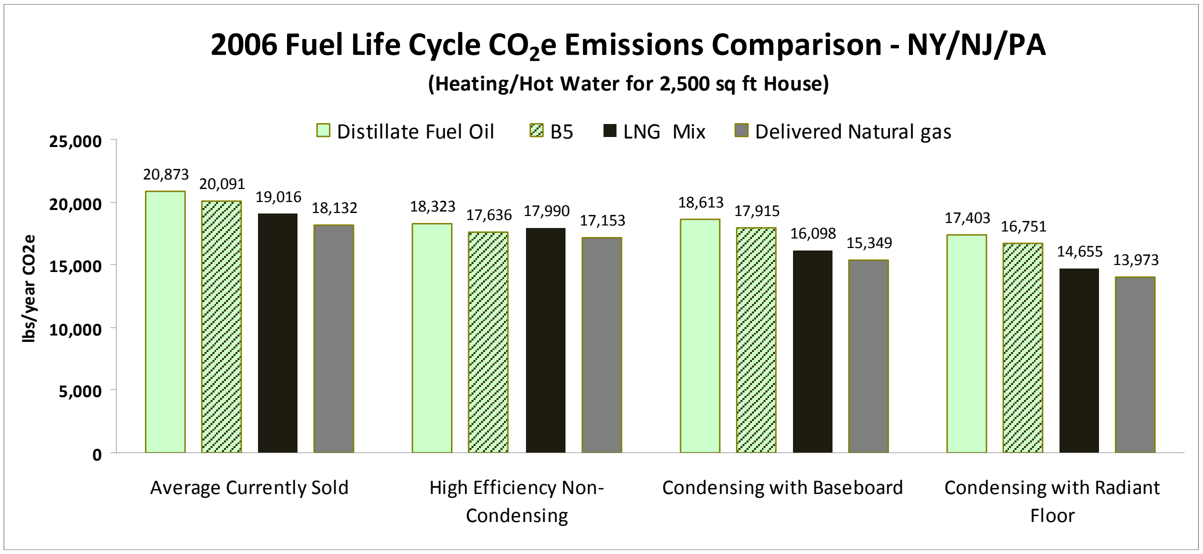


Figure 36 Heating System Emissions Comparison for New York/New Jersey/Pennsylvania in 2006

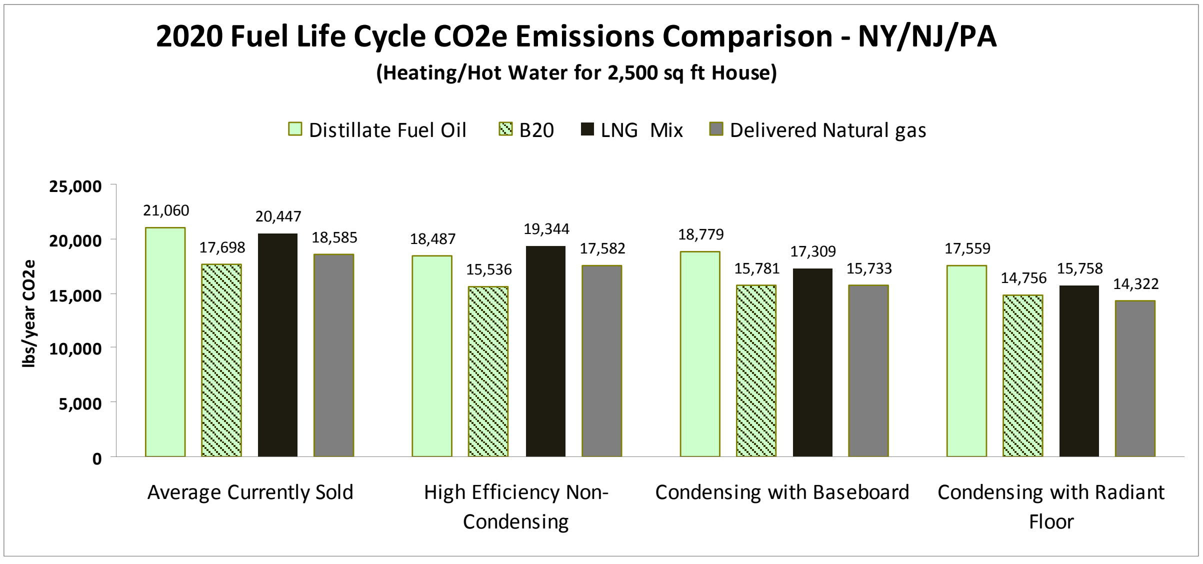


Figure 37 Heating System Emissions Comparison for New York/New Jersey/Pennsylvania in 2020

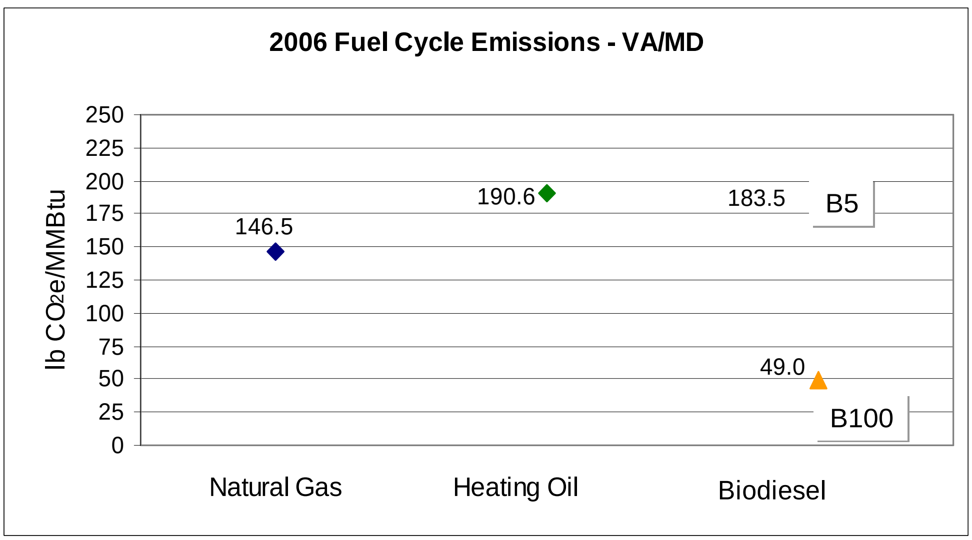
Virginia/Maryland

Virginia and Maryland are projected to experience significant changes in their natural gas supply mix over the time period of the analysis. As shown in **Table 111,** the region will see a significant decrease in gas from the Gulf Coast, and increases in gas from LNG shipments into East Coast and Gulf Coast terminals.

Table 111 Natural Gas Supply Mix into Virginia/Maryland

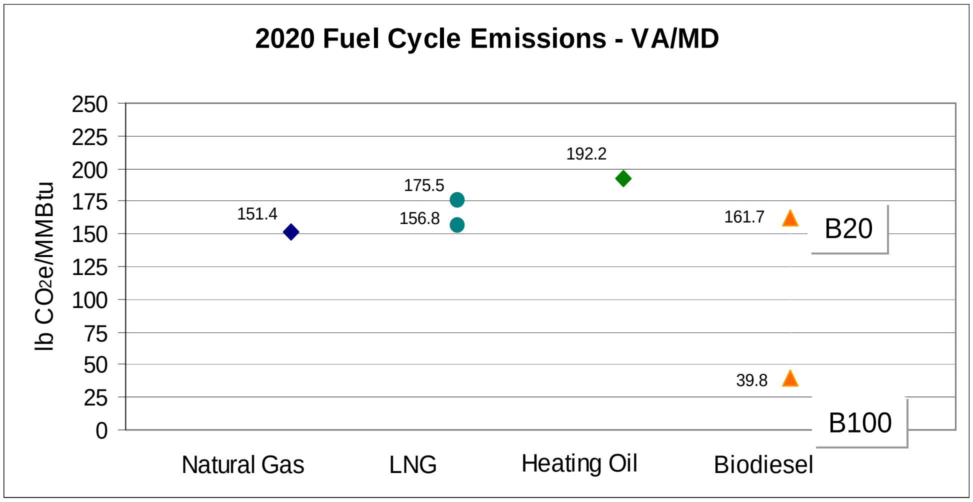
	2006		2020	
Supply Source	Supply Share	Pipeline Mileage	Supply Share	Pipeline Mileage
Rocky Mountains	0.5 %	1,940 miles	2 %	1,940 miles
Southwest	8 %	1,600 miles	8 %	1,600 miles
MidContinent	1 %	1,100 miles	2 %	1,100 miles
Gulf Coast	76 %	1,600 miles	41%	1,600 miles
East Coast LNG	14 %	200 miles	39 %	200 miles
Gulf Coast LNG	1 %	1,600 miles	8 %	1,600 miles
Total Supply	100%		100%	

Figure 38 and **Figure 39** show the resulting final fuel cycle emissions in pounds of CO_2 equivalent per MMBtu of fuel delivered (not including end use equipment efficiency) for each fuel type in 2006 and 2020. Natural gas delivered to this region has about 44 lbs CO_2e/MMBtu less GHG emissions than heating oil in 2006. The greater reliance on LNG in 2020 decreases this difference to 41 lbs CO_2e/MMBtu. LNG is included separately in **Figure 39** to illustrate the GHG emissions intensity of this marginal supply option for this region. B20 is about 10 lbs CO_2e/MMBtu higher in GHG emissions than delivered natural gas in 2020, and on a par with LNG imports into the region.



* CO_2 equivalent based on 100 year GHG warming potential

Figure 38 2006 Fuel Cycle Emissions Comparison for Virginia/Maryland



* CO_2 equivalent based on 100 year GHG warming potential

Figure 39 2020 Fuel Cycle Emissions Comparison for Virginia/Maryland

Figure 40 and **Figure 41** demonstrate the total annual resource energy comparison between average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas in Virginia/Maryland (including energy use along the fuel cycle and end use equipment efficiency). As with other regions, the energy consumption of oil systems is lower than that of natural gas systems in Virginia and Maryland for the average and high efficiency, non-condensing systems in 2006. The increase in resource energy consumption between 2006 and 2020 is also lower for oil than natural gas.

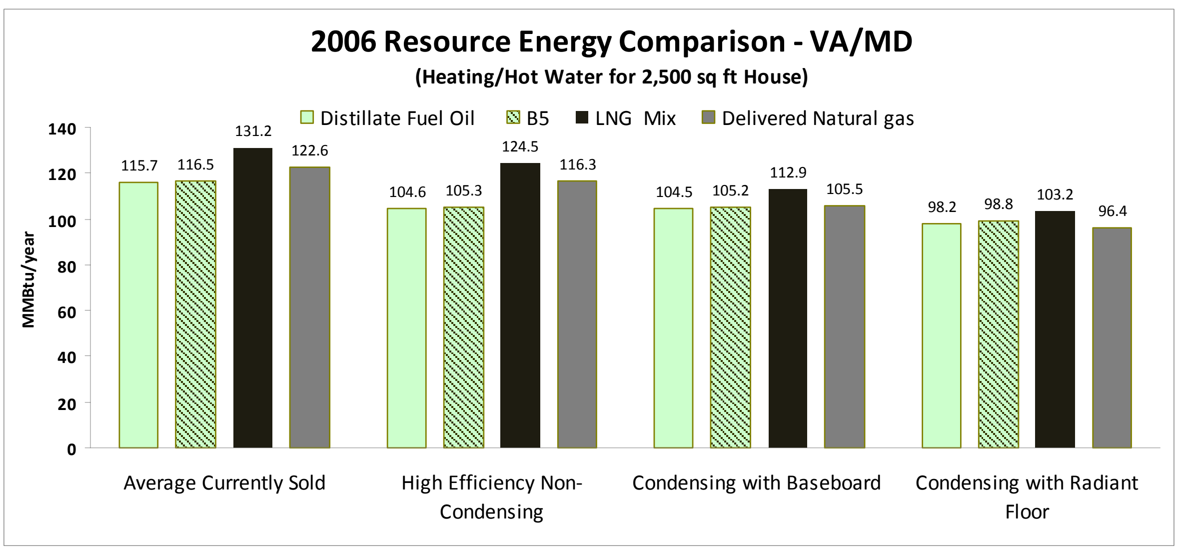


Figure 40 Heating System Energy Comparison for Virginia/Maryland in 2006

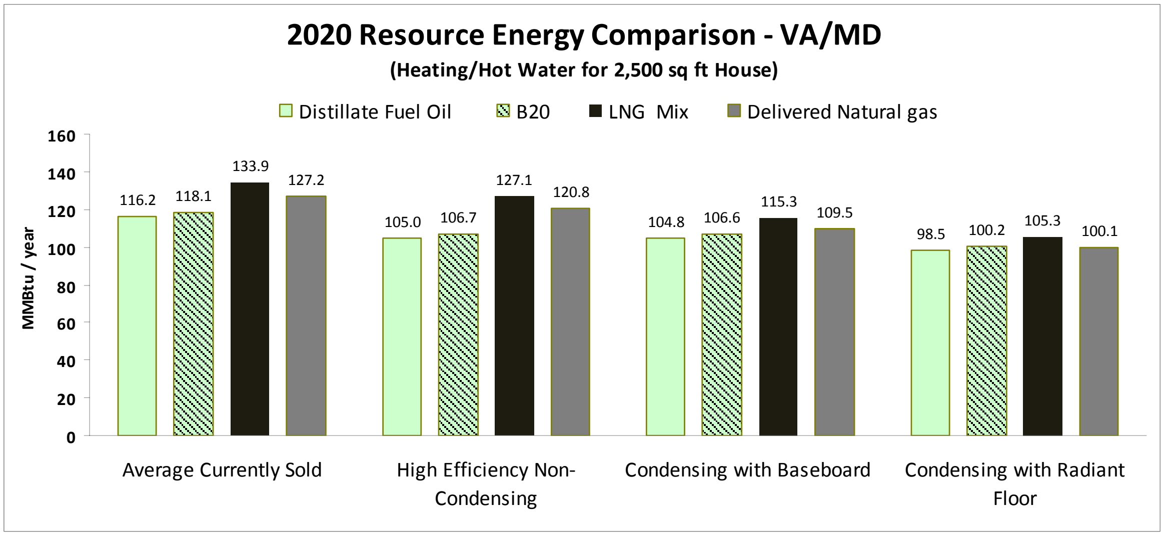


Figure 41 Heating System Energy Comparison for Virginia/Maryland in 2020

Figure 41and **Figure 43** show the resulting annual full fuel cycle GHG emissions based on the total annual energy consumption for the average, high efficiency non-condensing, and two types of condensing heating systems fueled by heating oil and natural gas. As with other regions, even though the energy consumption is higher for natural gas heating systems the annual GHG emissions are lower than the heating oil systems due to the fuel characteristics. Heating oil produces anywhere from 15 to 30 percent more GHG emissions than natural gas on an annual basis in 2006. The relative position of the two fuels in terms of GHG emissions remains unchanged 2020. Again, as in New England and NY/NJ/PA, B20 has lower emissions than delivered natural gas and marginal LNG for 2020 in both average and high efficiency, non-condensing systems.

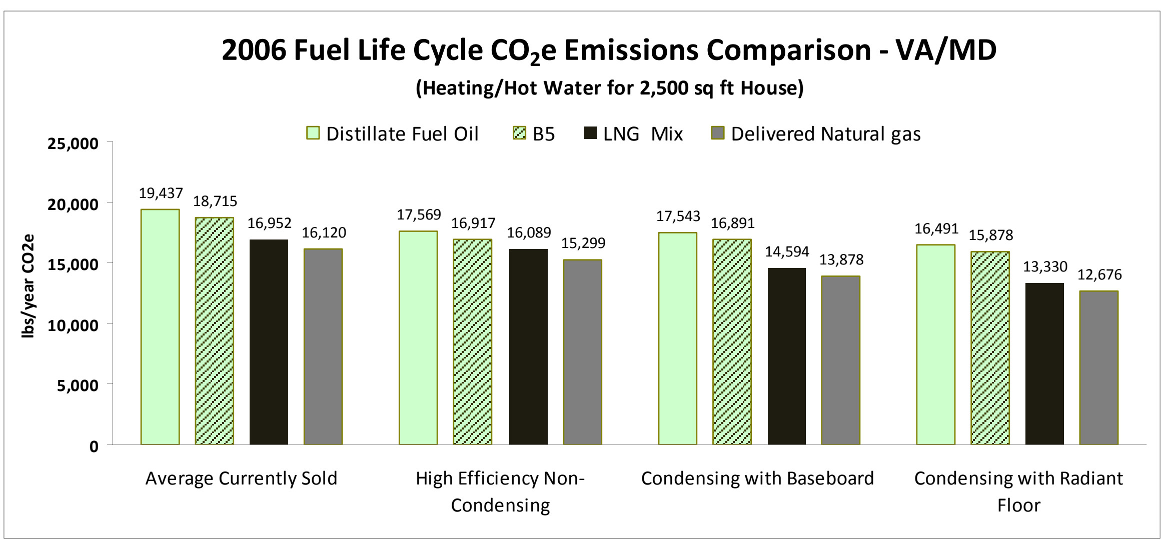


Figure 42 Heating System Emissions Comparison for Virginia/Maryland in 2006

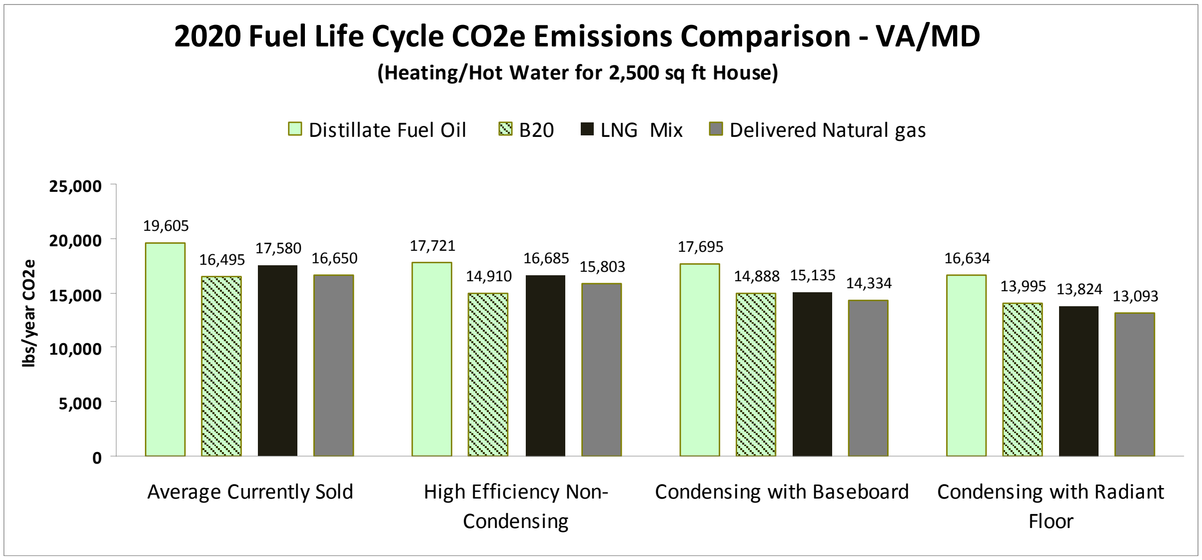


Figure 43 Heating System Emissions Comparison for Virginia/Maryland in 2020

7 FINDINGS

The analysis underscores the importance of considering the total resource energy use and fuel cycle emissions impacts of fuel consumption. Significant energy is consumed, with resulting emissions of CO_2 and other greenhouse gases (GHG), during all stages of the fuel cycle including the extraction/production, processing, transmission, distribution, and ultimate combustion stages. The fuel cycle emissions add 17 to 18 percent to the GHG emissions of heating oil combustion, and 25 to 30 percent to the GHG emissions of natural gas combustion at the burner tip (before end use equipment efficiencies).

The fuel cycle energy efficiency, a measure of the resource energy required to extract, process and deliver the fuel from well to burner tip (before end-use equipment efficiencies) is also a critical parameter. Fuel cycle efficiencies for heating oil remain in a fairly narrow band, ranging from 85.6 to 86.5 percent, with little change from 2006 to 2020. Fuel cycle energy efficiency for natural gas spans a broader range, ranging from 90.5 to 91.6 percent for natural gas delivered to Oregon-Washington and the Upper Midwest, and from 86.8 to 88.6 percent for natural gas delivered to the three market regions more distant from supply resources. These efficiencies are reduced in 2020, reflecting expected changes in the resource base of natural gas and particularly the reliance on LNG as a significant component of natural gas supply to the Northeast and Mid-Atlantic regions of the country. 2020 fuel cycle energy efficiency ranges from 90.0 to 90.6 percent for Oregon-Washington and the Upper Midwest and from 83.7 to 84.6 percent for New England, NY-NJ-PA and VA-MD.

The analysis also illustrates the importance of considering the efficiencies of end-use equipment in comparing fuel choices. Based on the 2006 resource and supply base, heating oil potentially produces 28 to 30 percent more GHG emissions than natural gas at the burner tip (before end-use equipment efficiencies) in terms of lb CO_2e/MMBtu for the regions under consideration; this changes to 25 to 28 percent in 2020. When compared on the basis of delivered energy services (including the efficiencies of end-use equipment), the incremental GHG emissions of heating oil over natural gas can be as low as 6 percent for the heating equipment most likely to be used in the marketplace (high efficiency, non-condensing units).

Finally, the analysis demonstrates that the evolution in fuel supplies over time should also be considered in comparing fuel choices. The potential use of biofuel blends can significantly alter the relative GHG emissions profiles of natural gas and heating oil. B20, a blend of 20 percent biofuel and 80 percent low sulfur heating oil, is estimated to have total GHG emissions for delivered energy services (including end-use equipment efficiencies) on a par with delivered natural gas in 2020. B20 can have up to 12 percent lower GHG emissions than LNG, the marginal natural gas supply option for the Northeast and Mid-Atlantic regions, depending on which heating equipment is considered.

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