Analysis of Fuel Cycle Energy Use and Greenhouse Gas Emissions from Residential Heating Boilers

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EXECUTIVE SUMMARY

Natural gas, heating oil and biodiesel blended with heating oil 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 fuel 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 compares the relative energy resources consumed and GHG impacts associated with pipeline natural gas, ultra-low sulfur heating oil, and soybean-based biodiesel blends (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 biodiesel products based on typical residential usage.

Analysis

The three main GHG emissions from the oil and natural gas fuel cycle are methane (CH₄), carbon dioxide (CO₂), and nitrous oxide (N₂O). 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 burner-tip, in terms of CO₂ equivalent, or CO₂e¹. This report also presents GHG emissions results for both conventional 100-Year Atmospheric Lifetime assessment and short-term carbon forcing assessment at 20-Year Atmospheric Lifetime². The individual GHG sources along the fuel cycle were classified into three categories: vented, fugitive, and combustion emissions.

 $^{^{1}}$ CO₂e (CO₂ equivalent) emissions include CO₂, N₂O and methane all calculated for their global warming potential (GWP) in terms of a CO₂ baseline = 1. This analysis used the recognized 100-year GWP time horizon with carbon feedback in evaluating the relative GWP of methane (36 x CO₂) and nitrous oxide N₂O (298 x CO₂) and recognized 20-year GWP time horizon in evaluating the relative GWP of methane (85 x CO₂) and nitrous oxide N₂O (264 x CO₂)

² In the mid-90s, policymakers for the Kyoto Protocol chose a 100-year time frame for comparing greenhouse gas impacts using GWPs. The choice of time horizon determines how policymakers weigh the short- and long-term costs and benefits of different strategies for tackling climate change. According to the Intergovernmental Panel on Climate Change, the decision to evaluate global warming impacts over a specific time frame is strictly a policy decision—it is not a matter of science: "the selection of a time horizon of a radiative forcing index is largely a 'user' choice (i.e. a policy decision)" [and] "if the policy emphasis is to help guard against the possible occurrence of potentially abrupt, non-linear climate responses in the relatively near future, then a choice of a 20-year time horizon would yield an index that is relevant to making such decisions regarding appropriate greenhouse gas abatement strategies." Short-lived pollutants that scientists are targeting today, which actually warm the atmosphere, are methane and hydrofluorocarbons (HFCs) which are greenhouse gases like CO₂; trapping radiation after it is reflected from the ground. There is a growing scientific movement to calculate GHG emissions potential based on the short-term carbon forcing gases.

- 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 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.

Assessing Biodiesel – Land Use Change

Calculating biodiesel GHG impact requires understanding that the cultivation of energy crops on agricultural land can lead to an indirect or induced land use change (ILUC). The impact of ILUC is that agricultural land now used for the energy crop area is no longer available for food and feed production, and cultivation for these purposes may be moved to other, possibly new, cultivated areas. To prevent the deforestation of tropical rainforests potentially caused by the cultivation of energy crops, there are calls to create induced land use change (ILUC) factors, which are then added to the carbon footprint of biofuels as additional CO₂ emissions. This approach is very controversial, especially since indirect land-use changes are extremely difficult to quantify. It is, for example, generally not known whether a replacement foodstuff is grown specifically due to a certain land use change or, if it is grown, the exact location. To achieve this, all regional and global trade relations would theoretically have to be included in the evaluation. The range of different studies and models are correspondingly broad. Nevertheless, this report includes the best available ILUC factors when presenting this data³.

Summary of Results

- It is critical to compare the energy and emissions performance of fuels in terms of the full fuel-cycle and actual (as opposed to rated) efficiencies at the point of use.
- Combustion of ultra-low sulfur heating oil (< 15 ppm sulfur) is the equivalent of natural gas combustion with respect to SO₂, NOx and particulates.
- Heating oil, with modest levels of soybean-based biofuel blending (20 to 25 percent), remains a competitive alternative to natural gas for residential heating in terms of overall energy use and GHG emissions based on conventional 100-year atmospheric lifetime calculations.

To illustrate, Boston is one of six cities where boiler performance and GHG emissions were calculated for natural gas, heating oil and heating oil/biofuel blends. Figure 1 shows that, for Boston, the GHG emissions of a typical replacement residential oil boiler using a B20⁴ blend are equivalent to the emissions from a typical replacement natural gas boiler based on 100-year

³ Awgustow A, et al, "Production of GHG-reduced liquid fuels", September 21 2017, TU Bergakademie Freiberg for Institut für Wärme und Oeltechnik IWO e.V.

⁴ B20 is 20% biodiesel and 80% ultra-low sulfur diesel



atmospheric lifetime calculations without considering induced land use change impacts. Blends up to B100⁵ have been used in the field today, with B20 blend being quite typical.

Figure 1 - 100 Year Atmospheric Lifetime with Feedback and without Indirect Land Use

• Heating oil with even lower levels of biofuel blending (7 percent) remains a competitive alternative to natural gas for residential heating in terms of overall energy use and GHG emissions based on carbon forcing 20-year atmospheric lifetime calculations.

Figure 2 shows that, for Boston, the GHG emissions of a typical replacement residential oil boiler using a B7⁶ blend of heating oil are equivalent to the emissions from a typical replacement natural gas boiler based on 20-year atmospheric lifetime calculations without considering induced land use change impacts. Again, blends up to B100⁷ have been used in the field today, with B20 blend being quite typical.

⁵ B100 (100% biodiesel) has been applied in the field, but very special care must be taken with respect to clod flow properties.

⁶ B7 is 7% biodiesel and 93% ultra-low sulfur diesel

⁷ B100 (100% biodiesel) has been applied in the field, but very special care must be taken with respect to clod flow properties.



Figure 2 - 20 Year Atmospheric Lifetime without Indirect Land Use

- The heating oil industry is actively incorporating existing biofuels into product blends in order to reduce GHG emissions and is working with suppliers to ensure these product blends are compatible with existing and new oil heating equipment.
- Advanced biofuels, such as ethyl levulinate, show even greater promise at reducing the GHG footprint of heating oil blends, well beyond the levels of competing fuels such as natural gas. Figure 41 illustrates the total annual GHG emissions from providing heating and hot water services to a representative 2,500 square foot house in the Boston area for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas. The graph shows that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually enables the potential for reduction of GHG beyond a neutral point a blend of 79% soybean-based biodiesel and 21% ethyl levulinate contributes zero total fuel cycle GHG emissions, based on using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.



Figure 3 - Heating System Emissions Comparison with Advanced Biodiesel Blends

Residential Heating Policy Implications

There are discussions among policy makers about converting the existing, primarily fossil-fueled residential energy infrastructure to electricity in order to meet GHG emissions goals. Such a conversion would require an unparalleled increase in renewable electricity production to meet increased demand without increasing GHG emissions from the power sector. Wind and solar energy are variable resources, and increased reliance on these resources opens the question of how to provide power if the immediate output of these resources cannot continuously meet instantaneous demand. The primary options to address this issue are to (i) curtail load (i.e., modify or fail to satisfy demand) at times when energy is not available, (ii) deploy large amounts of energy storage, or (iii) provide supplemental energy sources that can be dispatched when needed. It is not yet clear if it is possible to curtail loads, especially over long durations, without incurring large economic costs. There are no electric storage systems available today that can affordably and dependably store the vast amounts of energy needed to reliably satisfy demand using expanded wind and solar power generation alone. These facts have led many analysts to recognize the importance of maintaining a broad portfolio of electricity generation technologies, including low-carbon, high efficiency fossil-fueled sources, that can be dispatched when needed

In addition to technical limits on the sole reliance of renewable resources to meet the increased demand of economy-wide electrification, there are economic limits. The costs of expanding renewable capacity to meet this increased demand would be significant. Added to that would be the equally significant cost of expanding the electric transmission and distribution system. The Electric Power Research Institute (EPRI) evaluated both technical and economic limitations to electrification in its recent U.S. National

Electrification Assessment.⁸ EPRI concluded that there are significant cost and technology questions about the ability to convert more than 47% of end-use energy use to electricity even under the most aggressive scenario. It seems clear that ultimate decarbonization of the economy will require a mix of electrification in areas where technology and costs can support such conversions, and deployment of high efficiency, low carbon fossil-fuel end-use alternatives in many other regions.

Domestic liquid fuels have the potential to play an important role in the future national energy mix, with or without increased electrification. The high energy density of liquid fuels makes transporting and storage simple and cost-efficient, and technical advancements in biofuels and technology can provide low carbon energy services at the point of use, unburdening the electricity supply and transmission system, supporting grid stability and enhancing energy resilience:

- Advanced biofuel blends with ultra-low sulfur diesel heating oil can become a clean and costeffective net zero GHG emissions residential heat source alternative before 2050.
- Development of new, renewably fueled, thermally driven (heating only) heat pump technologies promise to rival source energy efficiencies of electric heat pumps and provide greater comfort at low ambient temperatures.

⁸ U.S. National Electrification Assessment, Electric Power Research Institute, April 2018,

INTRODUCTION

Natural gas, heating oil and biodiesel blended with heating oil 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 and/or fuel availability, 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. Focusing on sustainability in the built environment requires life cycle assessments of building products and equipment. Sustainable energy production and consumption also requires 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 the residential sector. 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 well result in higher overall energy consumption as well as higher levels of greenhouse gas (GHG) emissions⁹.

This report is an update to an analysis released in 2009 that compared the total energy resource energy requirements and fuel cycle GHG emissions for residential heating services supplied by natural gas, heating oil and biodiesel blends in high efficiency non-condensing boilers based on typical usage¹⁰. The three main GHG emissions from the oil and natural gas fuel cycle included in the 2009 report and in this analysis are methane (CH₄), carbon dioxide (CO₂), and nitrous oxide (N₂O). There have been considerable changes in the energy outlook for the United States since the 2009 report. At the time of the original study, domestic natural gas supplies were tightening and most projections forecast growing imports of liquefied natural gas (LNG) to satisfy consumer demand. At the same time, domestic oil production was peaking and future growth in U.S. petroleum consumption was also projected to be supplied by increased imports. Today, as a result of advances in new extraction techniques — drilling horizontal

⁹ 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 CO₂ and other greenhouse gases (GHG), during all stages of energy use.

¹⁰ "Resource Analysis of Energy Use and Greenhouse Gas Emissions from Residential Boilers for Space Heating and Hot Water", ICF International for Consortium of State Oilheat Associations Greenhouse Gas Project, February 2009

wells and hydraulic fracturing (fracking) – the U.S. is expected to become a net exporter of energy between 2020 and 2030¹¹ as shown in Figure 4.



Natural gas supply has been particularly transformed by these new techniques. Shale gas production, only 7.6 percent (1.4 trillion cubic feet (Tcf)) of total Lower 48 dry gas production in 2006, increased to 58.4 percent of total Lower 48 dry gas production in 2015 (15.8 Tcf)¹², even as overall gas production, and consumption, increased (Figure 4). LNG terminals originally built for imports in the mid-2000's are now being refitted for export. The U.S. Department of Energy (DOE) currently estimates that net exports of natural gas could reach 7.5 Tcf in 2040, or 18 percent of total U.S. production¹³.

As shown in Figure 4, the new extraction techniques are also revolutionizing domestic oil production, allowing oil (and associated gas) to be economically recovered from tight formations previously considered too expensive to develop. Domestic crude production grew from 1,856,340 thousand barrels in 2006 to 3,434,018 thousand barrels in 2015, increasing from 33.5 percent of total net crude supplies in 2006 to 57.7 percent in 2015^{6,14}.

¹¹ Annual Energy Outlook (AEO) 2017, U.S. Department of Energy, Energy Information Administration, <u>https://www.eia.gov/todayinenergy/detail.php?id=29433</u>

¹⁴ U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook (AEO) 2009

 ¹² U.S. Department of Energy, Energy Information Administration, <u>https://www.eia.gov/naturalgas/data.php#production</u>
 ¹³ U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook (AEO) 2017, <u>https://www.eia.gov/todayinenergy/detail.php?id=29433</u>



Figure 5 - Technology Is Transforming the U.S. Oil and Gas Industry

The objective of this updated analysis is to compare the relative energy resources consumed by and GHG impacts associated with pipeline natural gas, ultra-low sulfur heating oil and biodiesel/ultra-low sulfur heating oil blends (B5, B20 and B100) used for residential space heating boilers based on the current oil and natural gas supply situation in the U.S. As in the original analysis, 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 each of the fuels to the household. The analysis compares the total source energy requirements and life cycle CO_2 equivalent (CO_2e) emissions for heating services supplied by high efficiency natural gas, heating oil and biodiesel blends based on typical usage.

 CO_2e is a measure used to estimate the climate change impacts of various GHG emissions such as methane (CH₄) and nitrous oxide (N₂O) by converting them to a single unit - carbon dioxide equivalents (CO₂e). This conversion to a common metric is accomplished using the Global Warming Potential (GWP) of each gas as established by the Intergovernmental Panel on Climate Change (IPCC). Each GHG has a different capacity for capturing and re-radiating outgoing infrared radiation in the atmosphere, thereby contributing to climate change. GWPs therefore act as an 'exchange rate' for various GHGs, converting them into CO_2e in order to compare their climate change impacts. The IPCC, the primary authority on climate change science, periodically updates the GWP values, with each adjustment the result of advances in scientific understanding. Best practice dictates that the most recent GWP values be applied in emissions calculations as they reflect the most up to date representation of the global warming effect of GHG emitting activities. The IPCC's GWP values for CO_2 , CH_4 and N_2O from the most recent update, the Fifth Assessment Report (AR5), are shown in Table 1 below¹⁵.

	Global Warming Potential (GWP)			
	20 Year	/ear 100 year without 100 year w carbon-climate carbon-clim feedback feedback		
CO ₂	1	1	1	
CH4	85	30	36	
N ₂ O	264	265	298	

Table 1 - IPCC Fifth Assessment Report (AR5) Greenhouse Warming Potential

Each GHG's radiative forcing effect varies over time, which is why the IPCC publishes GWPs for 20 and 100-year time frames, with 100-year GWPs being the most widely adopted in GHG inventories. GHGs with a relatively short lifetime (12.4 years for CH₄, for example) will have a stronger GWP over a shorter time frame. In the AR5, the IPCC published for the first time two sets of 100 year GWP values, one that takes into account climate-carbon feedbacks, which measures the indirect effects of changes in carbon storage due to changes in climate, and one that does not include that feedback¹⁶. Although the IPCC does not explicitly provide an opinion on which set of GWPs should be adopted, it does state that "though the uncertainties range for these metric values [with climate-carbon feedback] is greater... these calculations provide a more consistent methodology"¹⁷.

Analytic Approach

Estimates of energy use and GHG emissions (carbon dioxide, methane, and nitrous oxide) for the full natural gas and heating oil fuel cycles up to the burner tip (production, processing, transmission and storage, and distribution) in this analysis are based primarily on the data in the current *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2015* (EPA GHG Inventory) released by the Environmental Protection Agency (EPA) in April 2017¹⁸. The annual EPA analysis is the official inventory of human-influenced GHG emissions for the U.S. and the only economy-wide inventory of those emissions. The inventory estimates the total greenhouse gas emissions across all sectors of the economy using national-level data such as fuel use. This includes estimates of GHG emissions from fossil fuel combustion, various industrial processes, and agricultural sources. The comprehensive greenhouse gas data presented in the Inventory comprise the official U.S. estimate of total national emissions that is submitted to the United Nations in accordance with the Framework Convention on Climate Change. The

¹⁶ IPCC (2013). Climate Change 2013: The Physical Science Basis. Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Technical Summary.

¹⁷ IPCC (2013). Climate Change 2013: The Physical Science Basis. Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Chapter 8: Anthropogenic and Natural Radiative Forcing.

¹⁵ Intergovernmental Panel on Climate Change (IPCC), Fifth Assessment Report (AR5), <u>https://www.ipcc.ch/report/ar5/</u>

¹⁸ Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2015, U.S. Environmental Protection Agency, April 2017, <u>https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks</u>

approach for calculating emissions for natural gas and petroleum systems generally involves the application of emission factors to activity data (e.g., average annual fugitive methane emissions per non-associated well times the number of wells). For many sources, the approach uses technology-specific emission factors that vary over time and take into account changes to technologies and practices, which are used to calculate net emissions directly. For others, the approach uses what are considered "potential methane factors" and reduction data to calculate net emissions. EPA continually reviews and updates the emissions factors as available information improves through reporting programs and peer-reviewed studies. In recent years, EPA has made significant revisions to emissions factors based on data submitted by petroleum and natural gas facilities under subpart W of the Greenhouse Gas Reporting Program (GHGRP)¹⁹. Each annual inventory recalculates emissions back to 1990, incorporating improvements in emissions factors and activity data as appropriate for past years. As such, more current inventories often have revised estimates of GHG emissions for the base years of previous GHG inventories. Because of this, comparisons of emissions changes over time should be based on the most current inventory available.

Energy use data and combustion-related GHG emissions in the inventory are further supplemented by information developed by the Department of Energy's (DOE) Energy Information Administration (EIA). While primarily a projection of energy use and production through 2050, EIA's *Annual Energy Outlook 2017²⁰* (EIA AEO 2017) includes detailed data on production and consumption of natural gas and oil for 2015, the reference year for this study. DOE also maintains these data from previous AEOs for prior years. Estimates of energy use and emissions from the EPA GHG Inventory and EIA AEO 2017 are also adjusted in certain cases to reflect insights gained in the bottom-up analysis conducted in 2009. These adjustments are discussed in the individual sections of the report where appropriate. Energy use and GHG emissions for the soybean-based biodiesel fuel cycle (agriculture, processing, transport, and blending) are based on energy and emissions estimates²¹ from recent work by the National Biodiesel Board incorporating data from the 2016 version of the GREET1 model. Energy use and combustion-related GHG emissions for petroleum-based heating oil are also based on results from the GREET1 model.

The 2017 EPA GHG Inventory is based on AR4 GWP values. This analysis updates the EPA inventory using AR5 values. The baseline results presented in this analysis are based on 100-year GWP values with carbon-climate feedback, but results for 20-year and 100-year without carbon-climate feedback GWPs are included for comparison.

The individual GHG sources along the fuel cycle are classified into three broad categories under a framework created by the American Petroleum Institute (API): vented, fugitive, and combustion emissions.

- ¹⁹ Environmental Protection Agency, Greenhouse Gas Reporting Program Subpart W, <u>https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems</u>
- ²⁰ Annual Energy Outlook (AEO) 2017, U.S. Department of Energy, Energy Information Administration, <u>https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems</u>
- ²¹ GREET1, The Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model, 2017 release, https://greet.es.anl.gov/

- 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" combustion refers to any combustion of fuel where energy is extracted for beneficial use along the fuel cycle, such as natural gas used as fuel in compressor engines and heaters. "Non-energy" combustion refers to any combustion of fuel in flares where there is no useful 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, the combustion process in using any type of fuel is not 100 percent efficient. The emissions from the combusted portion of the fuel are referred to as combustion emissions. Carbon dioxide is the primary combustion emission from combustion of natural gas and heating oil, but other combustion products, such as N₂O emissions, are produced as well²². There are no combusted CH₄ emissions. Un-combusted emissions are gases that pass through the combustion process without any chemical change. For example, some portion of CH₄ and CO₂ present in natural gas used as fuel pass through as un-combusted emissions. There are no un-combusted N₂O emissions associated with combustion of natural gas or heating oil.

Finally, the total energy use and GHG emissions of each fuel type (natural gas, heating oil, and soybeanbased biodiesel blends) are compared for typical boiler systems providing space heating to a standard home. 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.

²² Although N₂O emissions are present in combustion products, the 2009 analysis indicated that the N₂O levels from combustion are di minimis and are not included in this analysis.

NATURAL GAS FUEL CYCLE ANALYSIS

Introduction

Over the past decade, the U.S. natural gas industry has undergone a quiet revolution. The combination of hydraulic fracturing (fracking) and horizontal drilling technologies has allowed economic access to enormous quantities of unconventional natural gas, in particular shale gas which is found trapped within sedimentary shale rock formations and which is extracted by injecting sand, chemicals and water at high pressure. As shown in Figure 6, large deposits of shale gas and gas associated with tight oil plays (also economically accessible with fracking techniques) are located across the U.S. The most significant fields include the Barnett reservoir in Texas and the Marcellus reservoir that runs across New York, Pennsylvania and most of West Virginia. The U.S. Energy Information Administration estimates that the United States has about 200 trillion cubic feet of proved shale gas resources²³, and nearly 623 trillion cubic feet of additional unproved technically recoverable shale gas resources²⁴.



Figure 6 – Natural Gas Shale Deposits in the Lower 48 States

²³ U.S. Crude Oil and Natural Gas Reserves – Year End 2015, U.S. DOE Energy Information Administration, December, 2016, https://www.eia.gov/naturalgas/crudeoilreserves/

²⁴ World Shale Resource Assessment, U.S. DOE Energy Information Administration, September, 2015, <u>https://www.eia.gov/analysis/studies/worldshalegas/</u>

Large-scale natural gas production from shale formations using hydraulic fracturing techniques became a commercial reality in the Barnett reservoir in the early 2000s. As the commercial success of hydraulic fracturing was demonstrated in the Barnett formation, additional companies started drilling wells and by 2005 Barnett shale was producing almost half a trillion cubic feet (Tcf) of natural gas per year. As natural gas producers gained confidence in their abilities to profitably produce natural gas in the Barnett reservoir and the Fayetteville reservoir in northern Arkansas using the new techniques, producers started developing other shale formations—including the Haynesville in eastern Texas and north Louisiana, the Woodford in Oklahoma, the Eagle Ford in southern Texas, and the Marcellus and Utica shales in northern Appalachia. As shown in Figure 7, shale gas production grew rapidly, from less than 4 billion cubic feet (Bcf) per day in 2006 to over 45 Bcf per day in 2017.



Figure 7 – Monthly Shale Gas Production Levels

The shale gas revolution has significantly altered the U.S. gas market and the nation's energy mix. The development of shale gas and associated tight oil gas has led to a surplus of natural gas and substantially lower prices. LNG terminals built for imports have been retrofitted to support exports. Imports of natural gas into the U.S., primarily by pipeline from Canada and LNG from various sources, have dropped from 21 percent of total gas consumed in 2006 to 11 percent in 2015. EIA projects production from shale gas and associated gas from tight oil plays to be the largest contributors to natural gas production growth, accounting for nearly two-thirds of total U.S. gas production by 2040 as shown in Figure 7²⁵.

²⁵ U.S. Department of Energy, Energy Information Administration, Annual Energy Outlook (AEO) 2017, <u>https://www.eia.gov/outlooks/archive/aeo17/pdf/0383(2017).pdf</u>



Figure 8 – U.S. Natural Gas Production

The extensive natural gas pipeline network in the U.S. has more than 217,000 miles of interstate pipelines to deliver natural gas from producing regions to end users²⁶. However, the continued development of natural gas from shale formations such as the Marcellus and Utica formations that are outside of traditional gas producing areas is requiring new pipeline infrastructure and/or the repurposing of existing infrastructure. The vast majority of the gas consumed in the residential and commercial sectors continues to be 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 distribution systems to move the gas to residences and commercial establishments. About 1,000 different gas utilities buy and resell gas to residential and commercial gas customers throughout the U.S.

While the rapid development of the shale gas industry has been generally supported by both major political parties, U.S. public opinion has been mixed and not everyone has fully embraced continued development. Concerns have been raised about the environmental consequences and the sustainability of intensified extraction. These concerns stem from techniques involved in hydraulic fracturing which require large amounts of water – a scarce commodity in some extraction areas – and critics cite potential problems from spills, leaks and contamination from the chemicals used in extraction. Questions have also been raised about the levels of methane leakage from fracturing. And others have been concerned about potentially negative impacts on local life. The boom in extraction has affected areas unaccustomed to drilling, including various towns in Pennsylvania and the Dallas metropolitan area in Texas. A portion of the population seems to feel that the shale gas industry has moved too fast, lacks coherent regulation, and that a number of environmental, social, regulatory and legal questions have not been fully addressed.

²⁶ U.S. Department of Energy, Energy Information Administration, "Estimated Natural Gas Pipeline Mileage in the Lower 48 States, Close of 2008"

On the other hand, advocates of shale gas development argue that misconceptions about fracking are widespread and that no scientific evidence has demonstrated that the chemicals used in hydraulic fracturing contaminate water or air. In response to public concerns and ongoing debate, federal authorities and a number of states have taken steps towards developing a legal and regulatory framework to better manage the risks from unconventional gas extraction.

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, each which consume energy and emit greenhouse gases (GHG). This section describes the natural gas fuel cycle analysis, and the quantification of the energy and emissions of the activities that are required to deliver a unit of natural gas to the ultimate customer. The natural gas fuel cycle consists of four segments as shown in Figure 9:



Source: Based on U.S. DOE EIA, Delivery and Storage of Natural Gas

Figure 9 - The Natural Gas Fuel Cycle

Production - Natural gas is produced from dedicated gas wells that produce gas only, associated gas wells that produce both oil and gas, 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. Direct GHG emissions from production include fugitive and vented/flared methane and CO₂ from wells and gathering equipment, and combustion emissions from lease fuel - natural gas used in well, field,

and lease operations such as gas used in drilling operations, heaters, dehydrators, and field compressors²⁷.

- 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. Direct GHG emissions from natural gas processing include combustion emissions from plant fuel²⁸, and fugitive and vented/flared methane and CO₂ from processing. Indirect GHG emissions from this segment include emissions associated with imported electrical power used in processing plants.
- **Transmission** The transmission system for natural gas consists of a complex network of intrastate and interstate 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 direct combustion emissions from reciprocating engines and gas turbine used to drive large compressors at compressor stations located along natural gas pipelines, but also include fugitive and vented methane from pipeline equipment and natural gas storage facilities.
- **Distribution** Distribution is the final step in delivering natural gas to end users. Most consumers 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.

Energy and GHG emissions profiles for each of the four stages of the natural gas fuel cycle are based on annual gas industry data collected and analyzed by the Department of Energy (DOE) and Environmental Protection Agency (EPA), specifically:

- EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2015²⁹ is the official inventory of human-influenced GHG emissions for the U.S. and the only economy-wide inventory of those emissions. The Inventory estimates the total greenhouse gas emissions across all sectors of the economy using national-level data such as fuel use and specific process activity levels. This includes estimates of GHG emissions from fossil fuel combustion, various industrial processes, and agricultural sources. The Inventory was primarily used to estimate CH₄ and non-combustion CO₂ emissions for each of the four stages in the natural gas fuel cycle, and for combustion CO₂ emissions from natural gas flaring in production.
- DOE's Energy Information Administration's (EIA) *Annual Energy Outlook 2017³⁰* provides detailed data on natural gas production and consumption for 2015 and uses this data as the

²⁸ Natural gas used as fuel for compressors and heaters in natural gas processing plants

²⁷ Lease operations include well, lease, or field operations related to the exploration for or production of natural gas prior to delivery for processing or transportation out of the field. Gas used in lease operations includes usage for drilling operations, heaters, dehydraters, field compressors, and net used for gas lift.

²⁹ Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2015, U.S. Environmental Protection Agency, April 2017, <u>https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks</u>

³⁰ Annual Energy Outlook (AEO) 2017, U.S. Department of Energy, Energy Information Administration, <u>https://www.eia.gov/todayinenergy/detail.php?id=29433</u>

basis of its long-term projections to 2040. Data on natural gas used for lease and plant fuel and for transmission and storage were used to estimate fuel use and energy-related combustion emissions for production, processing and transmission. Natural gas end-use consumption data from the AEO were used to generate GHG emissions intensities (lbs CO₂e/MMBtu) for each of the four stages of the fuel cycle.

GHG emissions in the natural gas cycle were 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, 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 (re-fracturing), and other processes.
- Fugitive emissions are unintentional equipment leaks. These leaks occur at the wellhead, from separators, heaters, floating CO₂ roof tanks, and compressors along the fuel cycle.

Natural Gas Fuel Cycle Analysis

Table 2 summarizes key natural gas production and consumption data for 2006, the base year of the 2009 study, and for 2015, the reference year for this analysis and based on data from DOE's Annual Energy Outlook and natural gas production summaries^{31,32}. The table highlights the enormous changes in the U.S. natural gas industry over the last ten years, driven by the emergence of shale gas production which grew by over twelve-fold in that time frame. Production of shale gas increased from 1,070 Bcf in 2006, representing 5.8 percent of total U.S. dry gas production, to 13,530 Bcf in 2015, representing 50 percent of total dry gas production. Total U.S. gas supply increased by 27 percent between 2006 and 2015, while net imports decreased 73 percent. Total end-use consumption grew by 26 percent from 2006 to 2015, driven primarily by increased use in the industrial and electric generation sectors. Lease and plant fuel consumption increased by 40 percent and vented/flared gas by 123 percent over the timeframe, reflecting the shift in supply from conventional wells to shale gas and the dramatic increase in the number of wells. Transmission use of gas (pipeline compressor fuel) grew by 28 percent in line with increase in overall consumption and supply.

³¹ DOE Energy Information Administration, *Natural Gas Withdrawals and Production*, <u>https://www.eia.gov/dnav/ng/NG_PROD_SUM_DC_NUS_MMCF_A.htm</u>

³² DOE Energy Information Administration, *Annual Energy Outlook 2009, Annual Energy Outlook 2017,* <u>https://www.eia.gov/outlooks/aeo/</u>

	2006	2015
Total Dry Gas Production, Bcf	18,504	27,065
Total Shale Gas Production, Bcf	1,070	13,530
Shale Gas Production Percentage	5.8%	50.0%
Vented/Flared Gas, Bcf	129.5	289.5
Net Imports, Bcf	3,463	935
Net Pipeline Imports, Bcf	2,940	872
Net LNG Imports, Bcf	523	63
Total Supply*, Bcf	22,005	28,026
End-Use Consumption, Bcf	19,973	24,989
Transmission Consumption, Bcf	584	678
Lease and Plant Fuel Consumption, Bcf	1,142	1,579
Total Consumption, Bcf	21,699	27,246

*Includes supplemental gas

Table 3 presents a summary of the CO_2 and CH_4 emissions from the natural gas fuel cycle for 2006 and 2015, the reference year for this analysis. Again, estimates for both years are presented to highlight changes in emissions profile since the initial study and are based on the data and methodology used in the current EPA GHG Inventory. Note that the values for 2006 are based on the methodology and emissions factors in the current EPA GHG Inventory, and are not comparable to the 2009 study. Emissions are presented on an annual basis (kilo-tons/yr) and as emissions intensities³³ (lbs/MMBtu) for each major segment of the fuel cycle – production, processing, transmission and distribution. Specific emissions categories for each segment include CH_4 , non-combustion CO_2 , combustion CO_2 and indirect CO_2 emissions intensities were calculated by dividing the annual emissions values in kilo-tons by the total end-use consumption in MMBtu (2006 – 20,592 TBtu, 2015 – 25,764 TBtu)

³³ The emissions intensities in Table 3 are based on physical units of CO₂ and CH₄ and do not include GWP factors

	2006		2015		
	k-tons	lb/MMBtu*	k-tons	lb/MMBtu*	
CH₄					
Production	3,999	0.427	4,264	0.364	
Processing	456	0.049	445	0.038	
Transmission	1,215	0.130	1,349	0.115	
Distribution	818	0.087	439	0.038	
Total	6,488	0.693	6,497	0.555	
CO ₂ – Non-combustion	• •	• •			
Production	935	0.100	591	0.051	
Processing	21,214	2.266	23,713	2.025	
Transmission	41	0.004	39	0.003	
Distribution	25	0.003	14	0.001	
Total	22,215	2.373	24,357	2.080	
CO ₂ – Combustion					
Production - Flaring	7,959	0.850	17,994	1.537	
Production - Lease Fuel	42,896	4.583	62,522	5.339	
Processing - Plant Fuel	19,667	2.101	24,003	2.050	
Transmission - Pipeline Fuel	32,005	3.419	37,154	3.173	
Total	102,526	10.954	141,673	12.098	
CO ₂ – Indirect					
Production	17,971	1.920	18,152	1.550	
Processing	8,705	0.930	8,873	0.750	
Transmission	0	0	0	0	
Distribution	0	0	0	0	
Total	26,676	2.850	26,935	2.300	

Table 3 - GHG Emissions for the Natural Gas Fuel Cycle

* The emissions intensities are based on physical units of CO_2 and CH_4 (lbs/MMBtu) and do not include GWP factors

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 CO₂ emissions from lease fuel

consumption in gathering compressors and natural gas flaring, as well as CH₄ 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. Greenhouse gas emissions from gathering and boosting compressors are based on the amount of horsepower required to deliver the gas through gathering pipelines to the processing and the fuel used by the compressors. The primary basis for estimates of methane emissions from the natural gas production sector is the EPA GHG Inventory. The Inventory is also the primary source for non-combustion CO_2 emissions and for CO_2 emissions from natural gas flaring. Combustion CO_2 emissions from lease fuel³⁴ are based on DOE EIA's estimates of lease fuel consumption from the Annual Energy Outlook 2017. Electricity is also used in producing fields that have access to the power grid. Indirect CO₂ emissions estimates for gas production are based on the consumption estimates in the 2009 study which were based on data from the U.S. Census Bureau and 2015 average grid emissions factors from DOE EIA. According to the EPA Inventory, emissions from production (including gathering and boosting) accounted for 66 percent of CH₄ emissions from natural gas systems in 2015. Emissions from gathering stations, pneumatic controllers, liquids unloading, and offshore platforms account for most of the CH₄ emissions.

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, H₂S, CO₂, and fractionate liquids. Major GHG emissions sources associated with natural gas processing include CO₂ emissions from plant fuel combustion in compressors and heaters, and fugitive CH₄ emissions from compressors, including compressor seals. Most of the non-combustion CO₂ emissions come from acid gas removal (AGR) units, which are designed to remove CO₂ from natural gas. The primary basis for estimates of methane and non-combustion CO₂ emissions from the natural gas processing sector is the EPA GHG Inventory. Combustion CO_2 emissions from plant fuel³⁵ are based on DOE EIA's estimates of plant fuel consumption from the Annual Energy Outlook 2017. Combustion CO₂ comes from the energy use during processing; non-combustion CO_2 and CH_4 emissions come from gas venting and leaks. Electricity is also used in gas processing. Indirect CO₂ emissions estimates for gas processing are based on the consumption estimates in the 2009 study which assumed electricity was consumed primarily by pumps and for refrigeration, and 2015 average grid emissions factors from DOE EIA. According to the EPA Inventory, processing plants account for 7 percent of CH₄ emissions and 56 percent of noncombustion CO₂ emissions from natural gas systems.

³⁴ 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."

³⁵ Plant fuel is natural gas used in gas processing plants for compressor and pumps drives and process heaters.

Transmission

Natural gas transmission involves high pressure, large diameter pipelines that transport gas long distances from field production and processing areas to distribution systems or large volume customers such as power plants or chemical plants. Emissions from the transport of natural gas in North America occur chiefly from compressor exhaust at compressor stations located along the natural gas pipelines and in regional storage facilities. Estimates of combustion CO₂ emissions are based on the amount of annual pipeline natural gas consumption reported by the EIA Annual Energy Outlook 2017. Estimates of methane and non-combustion CO₂ emissions from the transmission sector are from the EPA GHG Inventory and includes fugitive and vented emissions and from pipeline equipment and natural gas storage facilities. Fugitive emissions from compressor stations and venting from pneumatic controllers account for most of the methane and non-combustion CO_2 emissions from this stage. Un-combusted engine exhaust and pipeline venting are also sources of CH₄ emissions from transmission. Compressors and dehydrators are the primary contributors to emissions from storage. 2015 emissions estimates include the Aliso Canyon leak event in Southern California which contributed to around 5 percent of total emissions for this segment in 2015. Methane emissions from the transmission and storage sector account for approximately 21 percent of emissions from natural gas systems, while CO₂ emissions from transmission and storage account for less than 1 percent of the non-combustion CO_2 emissions.

Distribution

Distribution pipelines take the high-pressure gas from the transmission system at "city gate" stations, reduce the pressure and distribute the gas through primarily underground mains and service lines to individual end users. There were 1,274,976 miles of distribution mains in 2015, an increase of 35 percent since 1990. Distribution system emissions account for seven percent of CH_4 emissions from natural gas systems and less than 1 percent of non-combustion CO_2 emissions, and result mainly from fugitive emissions from pipelines and stations. 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. Increased use of plastic piping, which has lower emissions than other pipe materials, has reduced both CH_4 and CO_2 emissions from this stage, as have station upgrades at metering and regulating (M&R) stations.

Natural Gas Total Fuel Cycle Energy Use and GHG Emissions

Table 4 and Table 5 summarize the energy use and GHG emissions by the natural gas fuel cycle for 2015. Values are presented for each of the four major fuel cycle segments, and represent the energy used and GHG emissions produced in delivering pipeline natural gas to the point of consumption (i.e., to the burner tip).

Fuel cycle energy use in Table 4 is separated into two categories:

• Fuel Use – the amount of natural gas use in each fuel cycle stage in terms of Btu per MMBtu of end-use natural gas consumption

 Electricity Use – the amount of electricity used in the fuel cycle in terms of Btu of resource energy (primary energy used to generate the electricity) per MMBtu of end-use natural gas consumption. The resource energy is based on the average U.S. grid heat rate for 2015 from the AEO 2017 (9,610 Btu/kWh)

As shown in the table, energy use through the fuel cycle to deliver natural gas to the end-user represents about 11 percent of the energy content of the delivered gas.

	Fuel Use	Electricity Use	Total Energy Use	
	(Btu/MMBtu)			
Production	45,670	13,872	59,542	
Processing	17,533	6,690	24,222	
Transmission	27,140	0	27,140	
Distribution	0	0	0	
Total	90,342	20,562	110,904	

Table 4 - Energy Use in the Natural Gas Fuel Cycle (2015)

The GHG emissions for the four-natural gas fuel cycle segments are shown in Table 4 and are categorized into four categories:

- Non-combustion CO₂ represents CO₂ emissions from processes other than combustion, specifically fugitive and vented CO₂ from oil well production and from gas processing.
- Combustion CO₂ represents all combustion related CO₂ emissions from energy and non-energy use (i.e., flaring) at each stage except for indirect emissions from grid electricity consumption
- CH₄ Emissions –emissions of methane converted to CO₂ equivalence using the AR5 100-year Global Warming Potential (GWP) with carbon feedback factor of 36
- Indirect CO₂ Emissions off-site emissions related to electricity from the grid. Indirect emissions are based on the average U.S. grid CO₂ emissions rate for 2015 from the AEO 2017 (1.55 lbs CO₂/kWh)

	Non- Combustion CO ₂	Combustion CO ₂	CH₄	Indirect CO ₂	Total
	(lbs CO2e/MMBtu)				
Production	0.050	6.875	13.107	1.550	21.583
Processing	2.025	2.050	1.367	0.750	6.192
Transmission	0.003	3.173	4.148	0.0	7.324
Distribution	0.001	0.0	1.350	0.0	1.351
Total	2.08	12.10	19.97	2.30	36.45

Table 5 - GHG Emissions in the Natural Gas Fuel Cycle (2015)	- Based on 100-year GWP with Feedback
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Table 6 shows a comparison of total natural gas fuel cycle GHG emissions for three AR5 Global Warming Potential (GWP) categories: 20-year GWP, 100-year GWP without carbon-climate feedback, and 100-year GWP with carbon-climate feedback (as used in Table 5). The CO_2e values vary between the categories due to varying GWP factors for methane which, as shown earlier in Table 1, are 85, 30 and 36 respectively. Combustion of natural gas at the point of use produces an additional 117.1 to 117.22 pounds of CO_2e per million Btu to each of the fuel cycle segment totals in in the table to produce the total fuel cycle emissions including combustion for natural gas. Ultimate GHG emissions to supply energy services to the user is also impacted by the efficiency of the end use equipment as described in Sections 5 and 6.

	20-Year GWP	100-Year GWP without Carbon- Climate Feedback	100-Year GWP with Carbon- Climate Feedback	
	(lbs CO₂e/MMBtu)			
Production	39.42	19.40	21.58	
Processing	8.05	5.96	6.19	
Transmission	12.97	6.63	7,32	
Distribution	3.19	1.13	1.35	
Total for Segments	63.63	33.12	36.45	
Final Combustion	117.22	117.10	117.12	
Total Fuel Cycle Emissions	180.86	150.22	153.57	

Table 6 - GHG Emissions in the Natural Gas Fuel Cycle including Final Combustion (2015)

HEATING OIL FUEL CYCLE ANALYSIS

Introduction

The U.S. oil industry has undergone its own revolution in the past ten years, driven by the same technology innovations that enabled the development of shale gas. Tight oil (also known as shale oil, shale-hosted oil or light tight oil) is light crude oil contained in petroleum-bearing formations of low permeability, often shale or tight sandstone. Economic production from tight oil formations requires the same hydraulic fracturing techniques and often uses the same horizontal well technology used in the production of shale gas. As shown in Figure 9, domestic crude oil production almost doubled between 2006 and 2015, driven entirely by the development of tight oil resources. In the latest Annual Energy Outlook, DOE EIA projects tight oil to remain the major contributor to domestic production through 2050, while cautioning that the future growth potential of domestic tight oil production depends on the quality of resources, technology and operational improvements that increase productivity and reduce costs, and market prices—factors with futures that are both interconnected and uncertain³⁶.





Figure 10 shows the development of tight oil production from 2004 through 2017. Over 80 percent of tight oil production has come primarily from resources in the Permian Basin in Texas and New Mexico which is also a major resource for conventional oil recovery, and from the Eagle Ford shale formation in Texas, and the Bakken formation in North Dakota and Montana. As shown in Figure 11, DOE expects these resources to provide the bulk of tight oil production well into the future.

³⁶ DOE Energy Information Administration, Annual Energy Outlook 2018, <u>https://www.eia.gov/outlooks/aeo/</u>



U.S. tight oil production-selected plays

Figure 11 – Tight Oil Production

Tight oil production carries many of the same environmental and regulatory controversy that shale gas development has elicited, particularly in the development of the Bakken and Eagle Ford shale formations. An additional issue is that the infrastructure for gathering and transporting associated natural gas to market is underdeveloped in some of the tight oil production regions, especially in the Bakken formation, and large volumes of gas flaring has accompanied tight oil development in these areas.

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, each consuming energy and emitting greenhouse gases (GHG). This section describes the heating oil fuel cycle analysis, and the quantification of the energy and emissions of the activities that are required to deliver a unit of heating oil to the ultimate customer. The heating oil fuel cycle consists of the following four segments:

- Production Energy is consumed in the process of 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 production activities are based on statistics for U.S. production. Production of imported oil is assumed to have the same energy and emissions profile as defined for domestic production.
- **Transportation and Storage** Imported oil is brought into the U.S. primarily by ocean tanker. Crude oil is transported to refineries from domestic production facilities and from import receiving terminals with a mix of pipeline, barge, and rail.
- **Oil Refining** Refineries produce a slate of petroleum products including heating oil. The energy and emissions associated with home heating oil are allocated 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 products.

• **Bulk Shipments and Retail Delivery** – Refined products are bulk shipped to storage and distribution terminals throughout using pipeline, barge, and rail shipments. Final distribution of home heating oil to customers is undertaken by oil delivery trucks.

Energy and GHG emissions profiles for each of the four stages of the heating oil fuel cycle are based on annual petroleum industry data collected and analyzed by the Department of Energy (DOE) and Environmental Protection Agency (EPA), and estimates for energy consumption and emissions for specific stages of the fuel cycle as developed by Argonne National Laboratory (ANL), specifically:

- EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 –2015³⁷ is the official inventory of human-influenced GHG emissions for the U.S. and the only economy-wide inventory of those emissions. The Inventory estimates the total greenhouse gas emissions across all sectors of the economy using national-level data such as fuel use and specific process activity levels. The Inventory was primarily used to estimate CH₄ and non-combustion CO₂ emissions for the production, transportation and storage and refining stages in the heating oil fuel cycle and for combustion CO₂ emissions from flaring in the refining stage.
- DOE's Energy Information Administration's (EIA) Annual Energy Outlook 2017³⁸ provides detailed data on oil production and consumption for 2015 and uses this data as the basis of its long-term projections to 2040. AEO data and other EIA date on crude oil sources and production, refinery petroleum products and refinery fuel use were used to estimate fuel use and energy-related combustion emissions through the fuel cycle. Crude oil and heating oil production data from the AEO were used to generate GHG emissions intensities (lbs CO₂e/MMBtu) for each stage of the fuel cycle.
- Argonne's *Greenhouse gases, Regulated Emissions, and Energy use in Transportation* (GREET)³⁹ model is an analytical tool that simulates the energy use and emissions output of various fuel combinations. Initially sponsored by the DOE's Office of Energy Efficiency and Renewable to compare life cycle fuel efficiency and emissions for various transportation fuel alternatives and vehicle options, GREET is a key tool used by DOE's Biomass, Fuel Cell Technologies, Vehicle Technologies and Geothermal programs to evaluate the GHG emissions for a variety of technology portfolios. GREET is also used for regulation development by agencies such as the U.S. Environmental Protection Agency and the California Air Resources Board. GREET was used to estimate fuel use and combustion emissions for all four stages of the fuel cycle, combustion

³⁷ Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2015, U.S. Environmental Protection Agency, April 2017, <u>https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks</u>

³⁸ Annual Energy Outlook (AEO) 2017, U.S. Department of Energy, Energy Information Administration, <u>https://www.eia.gov/todayinenergy/detail.php?id=29433</u>

³⁹ Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET-17), Argonne National Laboratory, 2017, https://www.anl.gov/energy-systems/downloads/argonnes-greet-model
emissions from flaring in crude production, methane emissions from bulk shipments and retail delivery, and electricity use and emissions in the production and refining stages.

Fuel use and GHG emissions intensities for the production and transportation segments are based on total crude production and refinery products. Fuel use and combustion GHG emissions for refining were based on an allocation to distillate products as developed by the GREET model.

GHG emissions in the heating oil fuel cycle were 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, 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 (re-fracturing), and other processes.
- Fugitive emissions are unintentional equipment leaks. These leaks occur at the wellhead, from separators, heaters, crude headers, floating CO₂ roof tanks, and compressors along the fuel cycle.

Heating Oil Fuel Cycle Analysis

Table 7 and 8 summarize key crude oil and distillate products production data for 2006, the base year of the 2009 study, and for 2015, the reference year for this analysis, based on data from DOE's Annual Energy Outlook and petroleum production summaries^{40,41}. Table 7 further highlights the significant changes in the U.S. petroleum industry since the earlier analysis. While apparent crude consumption increased by a relatively modest 7.4 percent from 2006 to 2015, domestic crude production increased by 85 percent, again with all of the increase coming from tight oil supplies; tight oil represented about 8 percent of domestic crude production in 2006, growing to just under 52 percent by 2015. As a result of increased domestic production, net imports fell by 27 percent over this time frame, decreasing from accounting for 66.4 percent of apparent crude consumption in 2006 to 42.3 percent in 2015.

⁴⁰ DOE Energy Information Administration, *Natural Gas Withdrawals and Production*, <u>https://www.eia.gov/dnav/ng/NG_PROD_SUM_DC_NUS_MMCF_A.htm</u>

⁴¹ DOE Energy Information Administration, *Annual Energy Outlook 2009, Annual Energy Outlook 2017,* <u>https://www.eia.gov/outlooks/aeo/</u>

	2006	2015
Crude Oil – Domestic Production, MMbbls	1,856	3,434
Tight Oil Production, MMbbls	146	1,778
Tight Oil Percentage	7.9%	51.8%
Crude Oil – Imports, MMbbls	3,693	2,687
Crude Oil – Exports, MMbbls	<u>(9)</u>	<u>(170)</u>
Crude Oil – Net, MMBbls	5,540	5,952

In addition to the revolution in domestic crude production, enactment of stricter environmental standards since 2006 has altered both the production and consumption of distillate fuel products in the U.S. Table 8 shows that while apparent domestic consumption of distillate fuel fell by 5 percent between 2006 and 2015, U.S. refinery production increased by 22 percent, supporting a growing export market for refined distillate products. In addition, the product mix was significantly impacted by environmental standards - low sulfur distillate products (< 15 ppm) represented about 38 percent of total distillate refinery production in 2006 and increased to 93 percent of distillate production in 2015.

	2006	2015
U.S. Refinery Production		
Distillate Fuel Oil, < 15 ppm, MMbbls	555.5	1,681.2
Distillate Fuel Oil, 15 - 500 ppm, MMbbls	575.7	39.5
Distillate Fuel Oil, > 500 ppm, MMbbls	<u>343.5</u>	<u>81.7</u>
	1,474.7	1,802.4
Imports		
Distillate Fuel Oil, < 15 ppm, MMbbls	40.8	50.2
Distillate Fuel Oil, 15 - 500 ppm, MMbbls	28.0	4.4
Distillate Fuel Oil, > 500 ppm, MMbbls	<u>64.3</u>	<u>18.6</u>
	133.1	73.2
Exports		
Distillate Fuel Oil, < 15 ppm, MMbbls	0.0	352.5
Distillate Fuel Oil, 15 - 500 ppm, MMbbls	23.4	37.4
Distillate Fuel Oil, > 500 ppm, MMbbls	<u>55.2</u>	<u>39.2</u>
	78.5	429.1
Apparent Consumption		
Distillate Fuel Oil, < 15 ppm, MMbbls	596.3	1,378.9
Distillate Fuel Oil, 15 - 500 ppm, MMbbls	580.4	6.5
Distillate Fuel Oil, > 500 ppm, MMbbls	352.6	<u>61.1</u>
	1,529.4	1,446.5

Table 8 – Distillate Products – Domestic Production, Imports and Exports

Table 9 provides a summary of the CO₂ and CH₄ emissions from the heating oil fuel cycle for 2006 and 2015, the reference year for this analysis. Again, estimates for both years are presented to highlight changes in emissions profile since the initial study and are based on the data and methodology used in the current EPA GHG Inventory. Note that the values for 2006 are based on the methodology and emissions factors in the current EPA GHG Inventory, and are not directly comparable to the 2009 study. Emissions are presented on an annual basis (kilo-tons/yr) and as emissions intensities⁴² (lbs/MMBtu) for each major segment of the fuel cycle – production, processing, transmission and distribution. The annual emissions estimates for the production stage represent emissions from domestic production only. However, the emissions intensities for production are generally applicable to both domestic crude production and imports. Specific emissions categories for each segment include CH₄, non-combustion CO₂, combustion CO₂ and indirect CO₂ emissions. Methane emissions from the heating oil fuel cycle are

⁴² The emissions intensities in Table 9 are based on physical units of CO₂ and CH₄ and do not include GWP factors

primarily associated with onshore and offshore crude oil production, transportation, and refining operations. During these activities, CH₄ is released to the atmosphere as fugitive emissions, vented emissions, emissions from operational upsets, and emissions from fuel combustion. Fugitive and vented CO₂ emissions are primarily associated with crude oil production and refining operations but are negligible in transportation operations. CO₂ from fuel combustion are associated with all four stages of the fuel cycle, while combustion CO₂ from flaring is associated with production and refining. Indirect CO₂ emissions from electricity consumption are also associated with the production and refining stages.

Production

Production field operations account for approximately 95 percent of total CH₄ emissions from petroleum systems. The predominant sources of emissions from production field operations are pneumatic controllers, offshore oil platforms, associated gas venting and flaring, gas engines, chemical injection pumps, oil tanks, hydraulically fractured oil well completions, and fugitives from oil wellheads. These sources alone emit around 95 percent of the production field operations emissions. The remaining emissions are distributed among around 20 additional activities. While domestic crude production increased by 85 percent between 2006 and 2015, CH₄ emissions actually decreased, reflecting improvements in technology and operations, and significant reductions in venting of associated gas. Note that the reduction in associated gas venting was accompanied by an increase in the CO₂ combustion emissions from flaring.

Production represents 79 percent of the non-combustion CO₂ emissions in the heating oil fuel cycle, and vented CO₂ associated with production field operations account for approximately 99 percent of the total CO₂ emissions from production field operations, while fugitive and process upsets together account for approximately 1 percent of the emissions. The principal sources of CO₂ emissions are oil tanks, pneumatic controllers, chemical injection pumps, and offshore oil platforms. These four sources together account for slightly over 97 percent of the non-combustion CO₂ emissions from production field operations, while the remaining 3 percent of the emissions is distributed among around 20 additional activities.

The increase in annual combustion CO_2 emissions from production generally reflects the increase in domestic production between 2006 and 2015. As mentioned earlier, the sharp increase in CO_2 combustion emissions from flaring of associated gas between 2006 and 2015 is a direct result of the infrastructure constraints of gathering and transporting associated natural gas to markets in many of the tight oil production areas, particularly in the Bakken and Eagle Ford formations.

	2006		2015	
	k-tons	lb/MMBtu	k-tons	lb/MMBtu
CH₄				
Production* – Associated gas venting	521.3	0.1065	42.5	0.0048
Production* – Flare	65.2	0.0133	105.7	0.0118
Production* – Vent, Fugitive and Fuel Use	1,233.0	0.2520	1,412.9	0.1583
Transportation and Storage	5.0	0.0003	8.4	0.0005
Refining – Vented, Fugitive and Fuel Use	17.0	0.0011	14.9	0.0009
Refining - Flare	10.1	0.0007	10.7	0.0007
Bulk Shipments and Retail Delivery	2.9	0.0007	2.8	0.0007
Total	1,855	0.3747	1,598	0.1778
CO ₂ – Non-combustion				
Production*	340.2	0.0695	641.4	0.0719
Transportation and Storage	0.0	0.0	0.0	0.0
Refining	191.1	0.0128	166.3	0.0105
Bulk Shipments and Retail Delivery	0.0	0.0	0.0	0.0
Total	531	0.0823	808	0.0824
CO ₂ – Combustion				
Production* – Fuel Use	9,770	2.000	17,468	1.960
Production* - Flare	4,942	1.012	24,883	2.753
Transportation and Storage	47,531	3.260	50,355	3.260
Refining – Fuel Use	195,133	13.571	209,617	13.570
Refining – Flare	3,402	0.227	2,760	0.175
Bulk Shipments and Retail Delivery	3,211	0.811	3,037	0.811
Total	263,989	20.881	308,120	22.530
CO ₂ – Indirect				
Production*	4,833.2	1.2009	3,640.4	0.9697
Transportation and Storage	0.0	0.0	0.0	0.0
Refining	6,052.4	1.5038	4,561.4	1.2150
Bulk Shipments and Retail Delivery	0.0	0.0	0.0	0.0
Total	10,885.7	2.7048	8,201.7	2.1848

*Production k-ton values based on U.S. domestic crude production only

Transportation and Storage

The transport of crude oil is transported to refineries from domestic production facilities and from import receiving terminals accounts for less than 1 percent of total CH₄ emissions from the oil industry. Venting emissions, including from tanks, truck loading, rail loading, and marine vessel loading operations account for 89 percent of CH₄ emissions from crude oil transportation. Fugitive emissions, almost entirely from floating roof tanks, account for approximately 11 percent of CH₄ emissions from crude oil transportation. Fuel combustion CO₂ emissions represent 14 percent of the total fuel combustion emissions for the heating oil fuel cycle.

Refining

Crude oil refining processes and systems account for approximately 2 percent of total CH₄ emissions from the oil industry. This low share is due to the fact that most of the CH₄ in crude oil is removed or escapes before the crude oil is delivered to the refineries. Within refineries, incomplete combustion accounts for around 50 percent of the CH₄ emissions, while vented and fugitive emissions account for approximately 34 and 15 percent, respectively. Flaring accounts for 82 percent of combustion CH₄ emissions. Refinery system blowdowns for maintenance and process vents are the primary venting contributors (97 percent). Most of the fugitive CH₄ emissions from refineries are from equipment leaks and storage tanks (87 percent).

Refining represents 13 percent of the non-combustion CO₂ emissions in the heating oil fuel cycle, primarily from process venting and asphalt blowing. Fuel combustion CO₂ emissions in refining were estimated based on an allocation for distillate products included the GREET model and represent 60 percent of the total fuel combustion emissions in the heating oil fuel cycle.

Bulk Shipments and Retail Delivery

Emissions from bulk shipping heating oil to storage and distribution terminals and final distribution of home heating oil to customers is relatively minor and limited primarily to fuel combustion CO₂ emissions.

Heating Oil Total Fuel Cycle Energy Use and GHG Emissions

Table 10 and Table 11 summarize the energy use and GHG emissions by the heating oil fuel cycle for 2015. Values are presented for each of the four major fuel cycle segments, and represent the energy used and GHG emissions produced in delivering heating oil to the point of consumption (i.e., to the residential burner tip).

Fuel cycle energy use in Table 10 is separated into two categories:

- Fuel Use the amount of fuel consumed in each fuel cycle stage in terms of Btu per MMBtu of end-use heating oil consumption
- Electricity Use the amount of electricity used in the fuel cycle in terms of Btu of resource energy (energy used to generate the electricity) per MMBtu of end-use heating oil consumption. The resource energy is based on the average U.S. grid heat rate for 2015 from the AEO 2017 (9,610 Btu/kWh)

As shown in the table, energy use through the fuel cycle to produce, refine and deliver heating oil to the end-user represents about 14 percent of the energy content of the delivered heating oil.

	Fuel Use	Electricity Use	Total Energy Use
	(Btu/MMBtu)		
Production	17,739	8,661	26,399
Transportation and Storage	18,110	0	18,110
Refining	84,463	10,852	95,315
Bulk Shipments and Delivery	4,635	0	4,635
Total	124,946	19,513	144,459

 Table 10 - Energy Use in the Heating Oil Fuel Cycle (2015)

The GHG emissions for each of the four-heating oil fuel cycle segments are shown in Table 11 and are categorized into four categories:

- Non-combustion CO₂ represents CO₂ emissions from processes other than combustion, specifically fugitive and vented CO₂ from oil well production and from gas processing.
- Combustion CO₂ represents all combustion related CO₂ emissions from energy and non-energy use (i.e., flaring) at each stage except for indirect emissions from grid electricity consumption
- CH₄ Emissions –emissions of methane converted to CO₂ equivalence using the AR5 100-year Global Warming Potential (GWP) with carbon feedback factor of 36
- Indirect CO₂ Emissions off-site emissions related to electricity from the grid. Indirect emissions are based on the average U.S. grid CO₂ emissions rate for 2015 from the AEO 2017 (1.55 lbs CO₂/kWh)

Table 11 - GHG Emissions in the Heating Oil Fuel Cycle (2015) – Based on 100-year GWP with Feedback

	Non- Combustion CO ₂	Combustion CO ₂	CH₄	Indirect CO ₂	Total
	(lbs CO2e/MMBtu)				
Production	0.072	4.712	6.298	0.969	12.051
Transportation and Storage	0.0	3.263	0.019	0.0	3.282
Refining	0.011	13.746	0.058	1.214	15.029
Bulk Shipments and Delivery	0.0	0.811	0.027	0.0	0.838
Total	0.082	22.53	6.40	2.18	31.20

Table 12 provides a comparison of total heating oil fuel cycle GHG emissions for three AR5 Global Warming Potential (GWP) categories: 20-year GWP, 100-year GWP without carbon-climate feedback, and 100-year GWP with carbon-climate feedback. The CO₂e values vary between the categories due to varying GWP factors for methane which, as shown earlier in Table 1, are 85, 30 and 36 respectively. Combustion of heating oil at the point of use produces an additional 162.04 to 162.40 pounds of CO₂e per million Btu to each of the fuel cycle segment totals in the table to produce the total fuel cycle emissions including combustion for heating oil. Ultimate GHG emissions to supply energy services to the user is also impacted by the efficiency of the end use equipment as described later sections of the report.

	20-Year GWP	100-Year GWP without Carbon- Climate Feedback	100-Year GWP with Carbon- Climate Feedback
	(lbs CO₂e/MMBtu)		
Production	20.63	11.00	12.05
Transportation and Storage	3.31	3.28	3.28
Refining	15.11	15.02	15.03
Bulk Shipments and Delivery	0.87	0.83	0.84
Total for Segments	39.91	30.13	31.30
Final Combustion	162.40	162.04	162.12
Total Fuel Cycle Emissions	202.31	192.17	193.32

Table 12 - GHG Emissions in the Heating Oil Fuel Cycle including Final Combustion (2015)

BIODIESEL FUEL CYCLE ANALYSIS

Introduction

Biodiesel can be made from a diverse mix of feedstocks including recycled cooking oil, soybean oil, and animal fats. It is the first and only EPA-designated Advanced Biofuel in commercial-scale production in the U.S. and the first to reach 1 billion gallons of annual production⁴³. Meeting strict technical fuel quality and engine performance specifications, it can be used in on-road diesel engines without modification and is covered by all major engine manufacturers' warranties, most often in blends of up to 20 percent biodiesel. The biodiesel market has increased from about 25 million gallons in the early 2000s to more than 2.8 billion gallons of advanced biofuel in 2016. This represents a small but growing component of the annual U.S. on-road diesel market of about 35 billion to 40 billion gallons. Consistent with projected feedstock availability, the industry has established a goal of producing about 10 percent of the diesel transportation market by 2022. Biodiesel is produced at plants in nearly every state in the country as shown in Figure 10.



Source: MyBioheat.com

Figure 12 – Biodiesel Production Facilities

Biodiesel blends are used in home heating oil systems as well -- Bioheat[®] fuel is the industry-accepted term for a blend of pure biodiesel combined with conventional ultra-low sulfur home heating oil. Biodiesel can be blended at any ratio with heating oil to create a Bioheat[®] blend. Pure biodiesel (ASTM

⁴³ National Biodiesel Board, <u>http://biodiesel.org/what-is-biodiesel/biodiesel-basics</u>

6751⁴⁴) is labeled B100 in this report. ASTM-D396 Standard Specification for Fuel Oils recognizes biodiesel blends up to 5 percent biodiesel (B5) as equivalent with #2 heating oil with respect to application and safety. The results from a Brookhaven National Laboratory in-use fuel survey, which include over 13,000 buildings using at least B20, show that B20 and lower blends operate in the field in a similar manner as that of conventional heating oil⁴⁵. Blends up to B100 are being successfully used in the field today and burner technologies are being developed to dynamically operate on varying degrees of biodiesel blends.

Biodiesel can be produced from a wide variety of feedstocks including recycled cooking oil, oilseed crops, and animal fats. Soybean oil is the dominant biodiesel feedstock in the U.S., and is the basis for the biofuels used in this analysis. Although soybeans do not produce as much oil per acre as other crops, such as canola or rapeseed, the United States is the largest producer of soybeans, producing approximately 32 percent of the world's supply, leading to substantial soybean oil production and its availability as a biofuel feedstock. Soybean oil is a co-product with soybean meal, a popular high-protein feed for animals. Soybeans are commonly grown as a rotation crop with corn to break insect, weed, and disease cycles, and the U.S. has a well-established infrastructure to process soybeans into oil and meal.



*Source: U.S. Department of Energy*⁴⁶

Figure 13 – Biodiesel Production Process

As shown in Figure 13, biodiesel is produced from vegetable oil or animal fat feedstock and an alcohol (methanol) through a transesterification reaction in the presence of a catalyst. The chemical reaction converts an ester (vegetable oil or animal fat) into a mixture of esters of the fatty acids that makes up the oil (or fat). The process leaves behind two products -- methyl esters (the chemical name for

⁴⁴ ASTM-D6751 Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels

⁴⁵ Industry Survey on the Use of Biodiesel (Bioheat[®]) Blends Thomas Butcher Brookhaven National Laboratory and John Huber National Oilheat Research Alliance April 2014

⁴⁶ https://www.afdc.energy.gov/fuels/biodiesel_production.html

biodiesel) and glycerin (a valuable byproduct usually sold to be used in soaps and other products). Biodiesel is obtained from the purification of the mixture of fatty acid methyl esters (FAME). Glycerin is sold for use in the manufacture of soaps and other household products.

Analytical Framework

This section describes the analytical approach of a full fuel cycle analysis of the energy used and GHG emissions associated with 100 percent biodiesel (B100) produced from soybean feedstock. The detailed analysis of biofuel production energy use and emissions is based on the GREET 2016 lifecycle assessment model⁴⁷. The GHG emissions from the biodiesel fuel cycle are primarily:

- Combustion CO₂ from the consumption of fossils fuels and electricity during the various fuel cycle stages, including the production and use of fertilizer and chemicals such as methanol, used in the growing and harvesting of soybeans and the processing of soybean oil into biodiesel, and
- Fugitive CH_4 and N_2O emissions from both the fuel cycle stages and production of fertilizer and biorefining chemicals

The biodiesel fuel cycle consists of the following stages:

- **Biofuel Agriculture** all of the activities associated with planting, tending, and harvesting soybeans.
- Extraction crushing of soybeans and extraction of the raw oil from the seed meal
- **Biodiesel Refining (Processing)** refining of the extracted soy oil to biodiesel by a process called *transesterifcation*
- **Transportation and Storage** transportation of crops to the crushing facility, transportation of the raw oil to the bio-refinery, and the final transportation of biofuel to blending facilities

Biodiesel Fuel Cycle Analysis

Biofuel Agriculture

13 summarizes the energy requirements for soybean agriculture as provided in the GREET 2016 model in Btu/MMBtu of B100 biodiesel (HHV). Electricity consumption is in terms of resource energy consumed in generation calculated at the 2015 U.S. average grid heat rate of 9,610 Btu/kWh.

⁴⁷ Argonne GREET Model. <u>https://greet.es.anl.gov/</u>

Agricultural Direct Energy Use	Btu/MMBtu
Natural gas	984
Electricity	2,633
Diesel Fuel	13,697
Gasoline	3,061
Propane	765
Total	21,140

Table 13 – Direct Energy Use for Agriculture

Fertilizer is also required for soybean agriculture. Energy embedded in fertilizer and other agricultural chemical use in terms of Btu/MMBtu of B100 biodiesel is shown in Table 14 based on GREET 2016.

Fertilizer Energy Use	Btu/MMBtu
Coal	1,735
Natural Gas	7,601
Petroleum	4,282
Total	13,618

Table 14 – Embedded Energy Use for Fertilizer/Chemicals

The emissions from soybean agriculture for biodiesel production are shown Table 15for each of the three primary greenhouse gases -CO₂, CH₄ and N₂O - in terms of pounds (physical units - GWP not applied) per MMBtu of B100 biodiesel. Note that fertilizer production generates a significant amount of N₂O emissions as part of its fuel cycle.

	CO ₂ Emissions	CH ₄ Emissions	N ₂ O Emissions
		(lbs/MMBtu)	
Agriculture	4.16	0.0097	0.0001
Fertilizer Manufacturing	2.25	0.0062	0.0443
Total	6.41	0.0171	0.0444

Table 15 – GHG Emissions for Soybean Agriculture

Soy Oil Extraction

Soy oil extraction consists of a series of processing steps:

- Soybean receiving and storage
- Soybean preparation
- Soybean oil extraction/crushing

- Soybean meal processing
- Soybean oil recovery
- Solvent recovery
- Oil degumming
- Waste treatment

The soybean meal is used as an animal feed. The soybean oil is recovered and prepared for the next production stage - refining at a dedicated biofuel refinery using a process called transesterification. Table 16 summarizes the energy requirements for soy oil extraction as provided in the GREET 2016 model in Btu/MMBtu of biodiesel (B100). Electricity consumption is in terms of resource energy consumed in generation calculated at the 2015 U.S. average grid heat rate of 9,610 Btu/kWh.

Soy Oil Extraction Direct Energy Use	Btu/MMBtu
Natural gas	27,074
Electricity	11,548
Diesel Fuel	208
Coal	13,334
Residual Oil	417
Total	52,581

Table 16 – Direct Energy Use for Soy Oil Extraction

Hexane is used as a solvent in soy oil extraction. Energy embedded in hexane use in Btu/MMBtu of B100 biodiesel is shown in the Table 17 based on GREET 2016.

Hexane Energy Use	Btu/MMBtu
Coal	11
Natural Gas	79
Petroleum	675
Total	765

Table 17– Embedded Energy Use for Hexane

The emissions for soy oil extraction in terms of lbs/MMBtu of B100 biodiesel for each GHG in physical units (GWP not applied) are shown in Table 18.

	CO ₂ Emissions	CH₄ Emissions	N ₂ O Emissions
		(lbs/MMBtu)	
Extraction	7.68	0.0223	0.0002
Hexane	0.02	0.0003	0.0000
Total	7.70	0.0226	0.0002

Table 18 – GHG Emissions for Soy Oil Extraction

Biofuel Processing

Biorefining includes a number of processing steps:

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

Table 19 summarizes the energy requirements for biodiesel refining as provided in the GREET 2016 model in Btu/MMBtu of biodiesel. Electricity consumption is in terms of resource energy consumed in generation.

Biodiesel Refining	Btu/MMBtu
Natural gas	25,745
Electricity	10,866
Total	36,611

Table 19 – Direct Energy Use for Biodiesel Refining

Methanol is used in the transesterification reaction to produce biodiesel. Energy embedded in the methanol used in the biorefining stage is shown in and Table 20 based on GREET 2016.

Methanol Energy Use	Btu/MMBtu
Coal	2,822
Natural Gas	71,261
Petroleum	1,114
Total	75,196

The emissions for biodiesel refining in terms of lbs/MMBtu of biodiesel for each GHG in physical units (GWP not applied) are shown in Table 21.

	CO ₂ Emissions	CH ₄ Emissions	N ₂ O Emissions
		(lbs/MMBtu)	
Refining	4.45	0.0170	0.0001
Methanol	10.57	0.0328	0.0001
Total	15.02	0.0498	0.0002

Table 21 – GHG Emissions from Biodiesel Refining

Biofuel Transport

There are three separate transportation and storage steps in the biofuel fuel cycle. First soybeans must be transported from the farm to the crusher. Soybean crushing/extraction facilities are generally located within major soybean producing areas. Typically, soybeans are transported 50 miles or less in heavy diesel trucks. A comparatively small amount of electric energy is used in loading and unloading in all three transportation steps.

Next, the crude soybean oil must be transported to the biofuel refinery. After refining, the biodiesel is transported to the final demand centers. The location of biofuel refineries of varies. They could be colocated at the crushing facilities, or they could be located near the distribution centers or anywhere in between. The distances that are assumed by GREET 2016 for intermediate transportation are shown in the following table.

Mode	Fraction	Distance, miles
Barge	40%	520
Rail	20%	700
Truck	40%	80

 Table 22 – Intermediate Transportation Assumptions

Biodiesel is finally transported from the biodiesel plant to the blending facility. The transportation modes and transportation distances assumed in the GREET 2016 model are shown in Table 23.

Mode	Fraction	Distance, miles
Barge	48.5%	200
Pipeline	46.4%	110
Rail	5.1%	490
Truck	100%	30

Table 23 – Retail Transportation Assumptions

Diesel and electricity energy usage in terms of Btu/MMBtu of biodiesel for the three transportation steps is shown in Table 24.

	Diesel	Electricity	Total
		(Btu/MMBtu)	
Transport to Crusher	5,698	849	6,547
Intermediate Transport	7,814	942	8,756
Retail Transport	4,463	1,957	6,420
Total	17,975	3,748	21,723

Table 24 – Transportation Energy Use

The emissions in terms of lbs/MMBtu of biodiesel for each of the primary greenhouse gases in physical units (GWP not applied) are shown for the three transportation steps in Table 25 based on the GREET 2016 model.

	CO ₂ Emissions	CH ₄ Emissions	N ₂ O Emissions
		(lbs/MMBtu)	
Transport to Crusher	1.03	0.0021	0.0000
Intermediate Transport	1.44	0.0027	0.0000
Retail Transport	1.01	0.0020	0.0000
Total	3.48	0.0068	0.0000

Table 25 – GHG Emissions from Transportation

Biodiesel Total Fuel Cycle Energy Use and GHG Emissions

Table 26 and Table 27 summarize the energy use and GHG emissions for the soybean-based biodiesel fuel cycle. Values are presented for each of the four major fuel cycle segments, and represent the energy used and GHG emissions generated in producing and delivering biodiesel to the blending facility.

Fuel cycle energy use in Table 26 is shown for two categories:

- Fuel Use the amount of fossil fuel use in each fuel cycle stage in terms of Btu per MMBtu of end-use biodiesel consumption
- Electricity Use the amount of electricity used in the fuel cycle in terms of Btu of resource energy (energy used to generate the electricity) per MMBtu of end-use biodiesel consumption

	Fuel	Electricity	Total
	(Btu/MMBtu)		
Agriculture			
Farm Use	18,507	2,633	21,140
Fertilizer	13,618	0	13,618
Total	32,155	2,633	34,758
Soybean Extraction			
Extraction	41,033	11,548	52,581
Hexane	765	0	765
Total	41,798	11,548	53,346
Biodiesel Refining			
Refining	25,745	10,866	36,611
Methanol/Chemicals	75,196	0	75,196
Total	100,941	10,866	111,807
Transport and Storage			
Transport to crusher	5,698	849	6,547
Intermediate Transport	7,814	942	8,756
Retail Transport	4,463	1,957	6,420
Total	17,975	3,748	21,723
Total Fuel Cycle to Burner Tip	192,839	28,795	221,634

Table 26 - Energy Use in the Biodiesel Fuel Cycle

The emissions for the biodiesel fuel cycle segments are shown in Table 27 for the three GWP categories: 100-year without feedback, 100-year with feedback, and 20-year.

	100-year w/o feedback	100-year with feedback	20-year
	(lbs CO₂e/MMBtu)		
Agriculture			
Farm Use	4.48	4.54	5.01
Fertilizer	14.18	15.68	14.48
Total	18.66	20.22	19.49
Soybean Extraction			
Extraction	8.39	8.53	9.61
Hexane	0.03	0.03	0.05
Total	8.42	8.56	9.66
Biodiesel Refining			
Refining	4.99	5.10	5.93
Methanol/Chemicals	11.57	11.77	13.37
Total	16.56	16.87	19.30
Transport and Storage			
Transport to crusher	1.09	1.10	1.21
Intermediate Transport	1.53	1.55	1.68
Retail Transport	1.08	1.09	1.19
Total	3.70	3.74	4.07
Total Fuel Cycle to Burner Tip	47.34	49.39	52.52

Table 27 - GHG Emissions from the Biodiesel Fuel Cycle

Induced Land Use Change (ILUC)

The cultivation of energy crops on agricultural land can lead to an Induced land use change (ILUC). The background to this is that the area is then no longer available for food and feed production and cultivation for these purposes may be moved to other, possibly new, cultivated areas. The (direct) land use change required there would then be seen as an indirect change in the use of the first area, where the energy crops are grown.

To prevent the cultivation of energy crops in the United States leading by this means to the deforestation of tropical rainforests, there are calls to introduce "ILUC factors", which are then added to

biofuels' carbon footprint as additional CO₂ emissions. This approach is very controversial, especially since indirect land-use changes are extremely difficult to quantify.⁴⁸

It is, for example, generally not known whether a replacement foodstuff is grown specifically due to a certain land use change or, if it is grown, the exact location. To achieve this, all regional and global trade relations would theoretically have to be included in the evaluation. The range of different studies and models are correspondingly broad⁴⁹.

Using residues such as waste fats or the black liquor produced during paper production, and producing algal biomass, does not cause any land use changes.

Indirect land use change emissions are modelled estimates of changes in carbon stocks (above and below ground) that might occur if cropland expands to meet higher demand for crops. Due to interactions among markets, trade among regions, and land competition between croplands and natural lands, land use change and related emissions as a consequence of producing biofuels becomes an issue that goes beyond the regions expanding biofuels production. Estimating biofuels induced land use change (ILUC) and emissions is a complex task. Large-scale economic models have been employed to simulate biofuels production and estimate the ILUC. These models are often coupled with an emission accounting model to calculate emissions from biofuels ILUC.

There are a number of models that have been used to estimate the required additional land that might be required and there are also several models that can be used to estimate the carbon changes from that land. The models that have been used in California are the GTAP-BIO model for land use changes and the AEZ model for carbon stock changes⁵⁰. The most recent version of these models indicate that the ILUC emissions for soybean biodiesel are 18 g CO₂eq/MJ of biodiesel (latest GTAP paper). The GTAP model can also be coupled with the GREET CClub model to provide the estimates of carbon stock change. The CClub model has a much more detailed accounting of carbon changes from pasture land in the United States and generally provides lower estimates than the AEZ model. The latest GTAP-CClub estimate for soybean biodiesel is about 6 g CO₂eq/MJ of biodiesel.

The land use models are being continually developed to better match the model results with the realworld observations. In general, the emissions estimates have declined as the models are improved. It is expected that this trend will continue as the models are further refined as even the latest version of

 ⁴⁸ F. Creutzig, N. H. Ravindranath, G. Berndes, S. Bolwig, R. Bright, F. Cherubini, H. Chum, E. Corbera, M. Delucchi, A. Faaij und J. Fargione, "Bioenergy and climate change mitigation: an assessment", GCB Bioenergy, Bd. 7, Nr. 5, pp. 916-944, 2015.
 ⁴⁹ B. Wicke, P. Verweij, H. van Meijl, D. P. van Vuuren und A. P. FaaiJ, "Indirect land use change: review of existing models and strategies for Biofuels", pp. 87-100, 3 2012.

⁵⁰ The land use change data entered into CCLUB comes from the latest version of Purdue's GTAP model, with elasticity values recommended by Purdue, Iowa State University, N.C. State University, and others (vs. elasticity values arbitrarily chosen by CARB staff); CCLUB treats ILUC emissions with a much higher spatial resolution than CARB's AE-ZEF approach (e.g., county-level vs. broad regional); CCLUB emission factors are based on actual field measurements of C fluxes via the CENTURY/ DAYCENT tools, which are recognized as the "gold standard" for measuring site-level C fluxes; and The CCLUB model has been peer-reviewed and published, whereas we are not aware that the AEZ-EF model has been peer-reviewed and published in the scientific literature. Source: http://www.ethanolrfa.org/policy/documents/rfa-comments-in-response-to-proposed-amendments-to-chapter-340-of-the-oregon-administrative-rules-oregon-clean-fuels-program/

GTAP is suggesting land use changes in the developed world that are not observed even though the biofuel production levels have exceeded the modeled demand increase.

Table 28 presents the GHG emissions for B100 for the three GWP categories, using the latest GTAP-CClub estimate of ILUC for soybean biodiesel.

	100-year w/o feedback	100-year with feedback	20-year	
	(lbs CO2e/MMBtu)			
Agriculture	18.66	20.22	19.49	
Soybean Extraction	8.42	8.56	9.65	
Biodiesel Refining	16.56	16.87	19.30	
Transport and Storage	3.70	3.74	4.08	
Total Fuel Cycle to Burner Tip	47.34	49.39	52.52	
Indirect Land Use, lbs/MMBtu	13.02	13.02	13.02	
Total Fuel Cycle to Burner Tip with Indirect Land use, lbs/MMBtu	60.36	62.41	65.54	

Table 28 - Total CO2e Emissions from Biofuel Fuel Cycle including ILUC

ADVANCED BIOFUELS

Introduction

Non-conventional fuels, and specifically biofuels, are often divided into generations, though often following arbitrary definitions. As shown in Table 29, alternative fuels in current use mostly fall under the first generation. Second and third generation products, meanwhile, are considered advanced biogenic fuels.

Generation	Resource	Product (examples)
1 st concration	Cultivated biomass	Biodiesel, bioethanol
Tegeneration	(e.g. cereals, oil plants, sugar beets)	hydrogenated vegetable oil
2nd generation	Biomass without usage competition to food (e.g.	Cellulose ethanol, synthetic fuel
2 th generation	waste wood, straw, green waste)	(BtL, bioSNG)
3 rd generation	Biomass produced independently from cultivated plants (e.g. algae)	Algae biodiesel, algae ethanol

Table 29 – Biofuel Generations

Basically, all carbon-based raw materials are potential candidates for the production of hydrocarbonbased fuels for internal combustion engines and turbines, or of liquid fuels. Types of biomass made from renewable sources of carbon, in particular, can play an important role in sustainable fuel production. Figure 14 provides an overview of the different raw material classes and the possibilities for obtaining liquid fuels.

Carbohydrates such as sugar, starch or cellulose, for example, can be broken down by means of fermentation to produce ethanol and higher alcohols, ketones or even aliphatic hydrocarbons. These are a suitable substitute for fuels either immediately or after chemical upgrading. The feedstocks which can be used are plants which contain sugar and starch, or lignocellulose (wood, straw).

Oil plants and different species of algae contain lipids, which can be extracted and relatively easily converted into fuels.

Any organic raw material can be converted into biogenic oils by means of direct liquefaction. As a rule, this produces blends with multiple ingredients, with a high proportion of oxygen and nitrogen, requiring complex processing in the form of hydrogenation.

Producing syngas (CO/H₂ mixtures) by means of gasification is another method which does not set high demands in terms of the reactants' chemical composition, meaning that lignocellulose or even undefined types of biomass come into consideration as raw materials. Syngas can also be produced without biomass, on the basis of carbon dioxide and water using electrical energy. Various synthesis methods (the Fischer-Tropsch process, methanol synthesis) can be used to convert the gases into high-

quality liquid sources of energy. Process chains of this type are known as biomass-to-liquid or power-toliquid (BtL, PtL) processes.



Figure 14 – Biofuels Raw Materials and Processing Options

One such advanced biofuel under field test for residential heating is ethyl levulinate (EL). This advanced biofuel has been blended with ULSD and biodiesel and will serve as part of the zero-carbon liquid fuel of the future in this study. Details of ethyl levulinate and its GHG emissions are presented below.

Biofine Process⁵¹

The Biofine process (Figure 15) is a high temperature, dilute acid-catalyzed rapid hydrolysis of lignocellulosic biomass. The process cost-effectively refines biomass into four principal products that can be separated and purified for sale: levulinic acid, a versatile platform chemical; formic acid and furfural, which are commodity chemicals; and a carbonaceous 'bio-char' consisting of over 60 percent carbon that can be burned or gasified to produce steam and electric power.

⁵¹ GHG calculations were excerpted from Dhaliwal H, Laurin L, "Comparison of Ethyl Levulinate with Gasoline and Diesel: Well to Wheels Analysis", EarthShift, June, 2009 study examined EL as a vehicle fuel.



Figure 15 Biofine Process

The process is carried out in a novel, continuous two-stage thermocatalytic reactor system that enhances the yield of the major product, levulinic acid, to over 70% percent of theoretical, making the process commercially viable. Unlike biological processes that can take several days for completion, the main biomass conversion process is very fast, being complete in under twenty minutes. Because of its non-biological, thermocatalytic nature, the process is flexible enough to utilize a wide range of lignocelluloses such as forest residues, waste paper, paper sludge or straw and other carbohydrate materials such as starch and sugars.

The process consists of five main continuous processing steps to convert raw lignocellulose to levulinic acid. The raw feedstock is chipped and fed to pre-treatment to remove hemicellulose. The high-cellulose residue is then slurried with dilute acid and pumped into the first-stage plug flow reactor, where the temperature is raised to 210 degrees Celsius (410 F). The residence time in the first reactor is 15 seconds.

The first-stage reactor breaks down the cellulose into a mixture of sugars and hydroxymethylfurfural. This mixture then flashes into a second stage, completely mixed reactor, where the sugars are converted to levulinic and formic acids in a residence time of fifteen minutes at below 200 degrees C (392 F). The insoluble char byproduct produced in the reaction is separated and levulinic acid is then extracted and purified from the clarified hydrolysate. Formic acid is extracted from the flash vapors and the pentose fraction of the pre-extracted hemicellulose is converted to furfural by acid-catalyzed dehydration.

Levulinic acid is known, at present, as a specialty chemical with limited markets in food, chemicals and pharmaceuticals. It is, however, an extremely versatile platform chemical that can be converted into a wide range of products. Levulinic acid has been identified by the U.S. DOE as one of the key chemicals in

the utilization of renewable cellulosic resources to displace chemicals made from crude oil or coal. The Biofine process has the potential to contribute significantly to DOE goals and allow biomass to displace crude oil as a primary source of fuels and chemicals.

Of particular commercial interest is the production of methyl and ethyl levulinate esters, versatile fuel products that can be mixed with biodiesel to form a low carbon footprint blend-stock for heating oil and commercial diesel. It is manufactured by the reaction of levulinic acid with either methanol or ethanol. The development of a renewable heating oil or transportation fuel blending component that can be blended with oil-seed-derived biodiesel, economically produced and used in a local environment is likely to be of great commercial and social interest.

Test work on levulinate esters in heating oil blends with biodiesel is currently being carried out in the U.S. at Brookhaven National Laboratory, NY. The market for heating oil in the U.S. is seven billion gallons per year. Blending levulinate esters at 5 percent would require the output from ten large-scale Biofine plants utilizing 1,000 dry tons per day of wood or another biomass.

Levulinic acid can also be converted to hydrocarbons chemically, e.g. via aldol condensation and hydrogenation, allowing the promise of renewable jet fuel to be produced directly from cellulose. Work on a thermal conversion process is currently under way at the University of Maine at Orono Chemical Engineering Department to optimize a direct non-catalytic thermal process that converts the output from the Biofine process into an energy-dense liquid hydrocarbon fuel with an energy content of around 18.06 KBtu/Pound.

Formic acid is a commodity chemical with a present-day market of over 500,000 metric tons. It is used in animal-feed ensiling, leather tanning and as an agricultural antibiotic. In response to a reduction in price, its present market can be expanded greatly. Formic acid can be used as a hydrogen carrier for fuel cells, as it spontaneously evolves hydrogen in contact with certain metal catalysts having the equivalent fuel value of hydrogen at 350 atmospheres. The ammonium salt, ammonium formate has advantages over urea as a means of scrubbing nitrogen oxides from boiler flue gas and vehicle exhausts.

Furfural is a commodity chemical with a present-day market of around 300,000 metric tons. It is used for the manufacture of foundry resins and in the production of lubricating oils. It can also be used as the starting material in production of other commodity chemicals such as furfuryl alcohol, butanediol and tetrahydrofuran. Furfural can be sold into the market or it can also be converted directly to levulinic acid, thus greatly increasing the yield of the main product of the process.

The carbonaceous bio-char consists of around 60 percent carbon. It is a mixture of carbon residue from the acid hydrolysis reaction and lignin in the original feedstock. It is produced as a finely divided, hydrophobic black powder that lends itself very well to dewatering and burning to provide all the energy the process requires. It has an energy content of 25 MJ/Kg. Alternatively, it can be used as a non-biodegradable soil amender and has potential as a feedstock for carbon fiber or activated carbon production.

A semi-commercial scale plant is now operational in Old Town, Maine that can process up to two tons per day of a variety of feedstock. It is a fully computer-controlled plant that can operate continuously for testing of feedstock and process optimization.

Greenhouse Gas Mitigation

The ethyl levulinate (EL) process is extremely attractive as part of a greenhouse gas mitigation strategy. It was recently assessed to have a greenhouse gas (GHG) life-cycle savings of over 90 percent compared to gasoline or diesel fuel and 40 percent compared to soy-based biodiesel by independent assessors using the USDOE-developed GREET methodology. In addition, the Biofine process affords the ability to produce formic acid from a renewable source, eliminating the use of fuel oil or butane in the conventional formic acid process. This gives an even higher greenhouse gas saving. The following analysis was performed to assess the GHG impact of producing ethyl levulinate blend-stock with ultralow sulfur heating oil and biodiesel.

Modeling Ethyl Levulinate in GREET

A detailed analysis was performed by EarthShift in 2009 to assess the well to wheels life-cycle GHG emissions of EL⁵². GREET default parameters were used as much as possible in evaluating the life cycle emissions, however, certain input parameters were changed to accommodate EL production and use. The production process for forest residue-based ethanol was adjusted to create a production process for EL. Therefore, the input parameters for feedstock were changed to a 100 percent forest residue. GHG emissions associated with caustic soda, sulfuric acid, ethanol and hydrogen (in case of 1,000 t/day plant) were added. Additionally, the "Fuel Specs" worksheet was modified to include fuel specifications of EL. The lower heating value, density and carbon ratio of ethanol was replaced by that of EL (103,045 Btu/gal, 3,785 grams/gal and 58.3 percent respectively).

Production of chemicals (e.g., fertilizers)

In case of the feedstock forest residue, no chemicals are used in its production (as indicated in GREET), the production of chemicals is therefore excluded for forest residue. For corn-based ethanol, the default GHG values for production of chemicals given in GREET are used.

Production of Feedstock

The default system boundaries for production of forest residue provided in GREET were used. Similarly, for corn-based ethanol production and natural gas-based hydrogen, the default system boundaries in GREET were used. For production of sulfuric acid and caustic soda, ecoinvent 2.0 data was used. The ecoinvent processes used here included the "cradle to gate"8 life cycle emissions associated with manufacturing of sulfuric acid and caustic soda. Additionally, the available ecoinvent data includes emissions from infrastructure related processes. For this analysis however, these processes were excluded. This was done to make the whole system consistent, as the GREET modules do not include infrastructure processes.

Transportation of Feedstock to manufacturing facility

For transportation of forest residue from the forest field to the facility, the default transportation process and distance (75 miles) provided in GREET was used, assuming that a comparable transportation distance is used to bring forest residue to the Biofine Technology's manufacturing facility.

⁵² "Comparison of Ethyl Levulinate with Gasoline and Diesel: Well to Wheels Analysis", EarthShift, June, 2009

For ethanol, the default transportation process and distance (520 miles by barge, 600 miles by pipeline, 800 miles by rail and 80 miles by truck) for the transportation of corn-based feedstock to manufacturing facility, given in GREET was used. It is assumed here again that a comparable transportation distance would be involved for transportation of ethanol to Biofine Technology's facility. Default transportation parameters for hydrogen were taken from GREET as well.

In the case of caustic soda (50%) and sulfuric acid, the ecoinvent 2.0 transportation process was used. Transportation distances from the chemical manufacturing plant in Illinois to the EL manufacturing facility in Maine, as indicated by Biofine Technology, were used: Caustic soda – 1410 miles, in a 16-32-ton truck Sulfuric acid – 1410 miles, in a 16-32-ton truck

Production of Ethyl Levulinate (50 and 1000 t/day plant size)

The production process of EL involves acid catalyzed hydrolysis of cellulosic material under high temperature. The process inputs for the manufacturing EL included sulfuric acid to hydrolyze the forest residue, caustic soda (50 percent), ethanol, steam, compressed air and electricity (see Table 30).

Along with the primary product, EL, the manufacturing process yields three coproducts – furfural, formic acid and char. The coproduct char is used within the system to produce heat and electricity. The surplus electricity from char is sent to the grid. The GHG emissions from combustion of biomass to generate steam and electricity were taken from GREET (16,039 and 9,212 grams CO₂ per gallon EL for 50 t/day and 1,000 t/day plants respectively). In the case of the 1,000 t/day capacity plant, the coproduct furfural is converted into EL. For this plant size an additional process input - hydrogen, is used for the conversion of furfural.

Plant size	50 dry ton/day	1000 dry ton/day	
Process Inputs	Amount (kg/day)	Amount (kg/day)	
Forest Residue (dry wt.)	50,000	1,000,000	
Sulfuric Acid	72 1,400		
Caustic Soda (50%)	121 3,400		
Ethanol (corn based)	4,571	158,300	
Hydrogen (from natural gas)	-	2,700	
Electricity	1.4MW	20.7MW	
Process outputs	Amount (kg/day)	Amount (kg/day)	
EL	12,980	440,000	
Char	33,380	667,600	
Furfural	6,450	Converted to EL	
Formic Acid	4,400	88,000	

Table 30 - Ethyl Levulinate Production Information

Plant size	50 ton/day	1000 ton/day
Process Inputs	Amount (kg/day)	Amount (kg/ day)
Char	33,380	667,600
Process outputs	z ess outputs Amount (kg/day)	
Steam (HP-500psi)/(LP-40psi)	107,000/ 180,000	2,277,600/2,277,600
Electricity (exported to grid)	2 MW	30 MW

Table 31 - Char Process Parameters

Transportation and Distribution of Ethyl Levulinate

The default transportation and distribution values given in GREET for ethanol were used for transportation and distribution of EL. GREET appears to give a total of 2,000 miles for transportation of ethanol (520 miles by barge, 600 miles by pipeline, 800 miles by rail and 80 miles by truck), and 30 miles (by truck) for distribution of ethanol. These distances were not changed for EL. It is assumed that transportation and distribution for EL would be comparable to ethanol.

Results – GHG Emissions

Ethyl Levulinate GHG Emissions (50 t/day plant)

Table 32 shows summary results of the GHG analysis using compiled feedstock and fuel data converted to delivered EL blend stock for heating oil. In the feedstock and fuel production stages of EL, the results show a high credit of -345 and -110 grams of GHG emissions per mile fuel used⁵³. The GHG credit is primarily due to: a) the sequestered CO_2 in the biomass-based fuel, b) the surplus electricity generated from char and c) the coproduct formic acid. The sequestration of CO_2 occurs during the growth of the tree, and it is this sequestered CO_2 that is being taken as a CO_2 credit. In case of electricity, the EL production process utilizes only 1.4 MW, the surplus electricity (2 MW) creates a GHG credit. Lastly, the formic acid (methyl formate based) displaced by the coproduced formic acid is leading to a GHG credit.

Feedstock	Fuel	Total	Units
-344.9	-110.2	-455.1	grams per mile from report
-7173.5	-2291.5	-9465.0	grams /gallon @ 20.8 miles/gallon
-15.9	-5.0	-20.80	lbs/gallon
-0.000153154	-4.89241E-05	-0.00020208	lbs/Btu @ 103,045 Btu/gallon
-153.2	-48.9	-202.1	lbs/MMBtu

Table 32 – Delivered EL Fuel GHG Reductions (50 ton/day plant)⁵⁴

⁵³ Ibid

⁵⁴ Summary GHG report provided data for transportation (grams per mile), this table convers this to lbs/MMBtu of delivered fuel

Ethyl Levulinate GHG Emissions (1,000 ton/day plant)

Table 33 shows results of the analysis using compiled feedstock and fuel data converted to delivered EL blend stock for heating oil for a 1,000 ton/day plant. The overall efficiency of the system has increased in terms of higher EL production; however, as the yield of the coproduct formic acid has decreased, there is a reduction in the allocation to formic acid. Also, there is an additional input of hydrogen that has relatively high impacts in this system. Therefore, the GHG reduction in the fuel production stage is lower in comparison to the 50 t/day plant.

Feedstock	Fuel	Total	Units
-350.4	-71.8	-422.2	grams per mile from report
-7288.7	-1493.9	-8782.6	grams /gallon @ 20.8 miles/gallon
-16.0	-3.3	-19.3	lbs/gallon
-0.000155614	-3.18937E-05	-0.00018751	lbs/Btu @ 103,045 Btu/gallon
-155.6	-31.9	-187.5	lbs/MMBtu

The 1,000 ton/day plant emission numbers were used to indicate the impact of ethyl levulinate blending in advanced biofuels on liquid fuel heating oil GHG emissions in the GHG impact chapter.

⁵⁵ Summary GHG report provided data for transportation (grams per mile), this table convers this to lbs/MMBtu of delivered fuel

RESIDENTIAL END-USE EFFICIENCIES⁵⁶

Introduction

The previous sections have established the energy and emissions impact of bringing heating oil, natural gas, and biofuels 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 CO₂ 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 16 shows that heating, cooling and domestic hot water (DHW) use account for 58 percent of the energy consumed by homes in the U.S.⁵⁷. 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 16 - 2010 Residential Buildings Site Energy End-Use

⁵⁶ This section is based on the work of Dr. Thomas Butcher at Brookhaven National Laboratory

⁵⁷ 2011 Buildings Energy Data Book, U.S. Department of Energy, 2010 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)⁵⁸ 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 procedure⁵⁹ which has also been adopted as part of a national labeling procedure.

The ASHRAE test standard for commercial boilers which provides an interesting alternative methodology provides a good means of assessing performance. 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, one for each 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.

⁵⁸ 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.

⁵⁹ 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 or a plate heat exchanger (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 Laboratory⁶⁰ 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 17 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 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

⁶⁰ Performance of Integrated Hydronic Systems, Project Report, May 1, 2007, Thomas A. Butcher, Brookhaven National Laboratory

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 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 17 - 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 demonstrated that the input/output method 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 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 GHG emitted, is dependent upon the location, building annual heat and hot water demand, and system efficiency. In this section, an analysis of fuel

use was done primarily to illustrate the fuel use of new, upgraded systems relative to the older installed base of systems. As discussed above, the focus 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 was done only for one home type – a 2,500 ft² ranch home with a basement with typical "code" construction. The hourly heating load for this home in six different cities was calculated using the Energy-10 modeling software⁶¹. Hourly heat demand was exported to a separate file and then DHW demand was added for each hour to determine the total hourly load on the integrated hydronic system for each hour of the year. The DHW load was based on 64.3 gallons per day⁶² and a demand distribution based on field data⁶³.

Boiler and Domestic Hot Water System Results

The analysis for all cases was done with two major variants – boiler space heating with domestic hot water (DHW). Table 34 provides the results with domestic hot water load included. The systems selected for end use comparison on this study are considered typical replacement boilers in existing homes (about 2,500 ft² in size) representing systems that just meet the current minimum AFUE efficiency standard.

Note that these systems were selected with respect to their potential GHG impact because they represent the logical construct for examining current practice and near-term potential for ultra-low sulfur heating oil, biodiesel blends, and pipeline natural gas with respect to retrofit construction and actual performance. GHG emissions comparisons of the two systems using these fuels is presented in the following chapter.

Boiler & DHW Comparison			Location					
Description	Thermal Eff. %	Idle Loss (%)	Baltimore, MD	Boston, MA	Madison, WI	New York, NY	Norfolk, VA	Seattle, WA
Typical replacement natural gas boiler in existing homes	82	1	104.40	122.40	163.20	112.20	75.70	98.20
Typical replacement oil boiler in existing homes	84	0.5	97.16	114.95	154.85	104.81	69.08	91.05

⁶¹ Energy-10 Software site, Sustainable Building Council,

http://www.sbicouncil.org/displaycommon.cfm?an=1&subarticlenbr=112 June 13, 2008.

⁶² Method of Testing for Rating Residential Water Heaters, ASHRAE Standard 118.2-2006, American Soc. of Heating, Refrigeration, and Air-Conditioning Engineers, Inc., 2006.

⁶³ <u>HVAC Applications</u>, American Soc. of Heating, Refrigeration, and Air-Conditioning Engineers, Inc, 2003.

OVERALL GHG EMISSIONS COMPARISONS

Introduction

This section presents a comparison of GHG emissions for natural gas and heating oil considering both the fuel cycle analyses and ultimate end use heating system efficiency. Each demand region discussion contains comparative graphs, based on updated 2015 data, of the fuel cycle (up to the burner tip) GHG emissions intensity of each fuel type (pipeline natural gas, heating oil, and biodiesel blends (B10 – B100 in 10% increments) and advanced biofuel blends (heating oil, biodiesel and ethyl levulinate).

Final Fuel Cycle GHG Emissions

The analysis includes an estimate of the annual full fuel cycle GHG emissions to provide space heating and hot water energy services for natural gas, heating oil and biofuel blends for typical replacement boilers being sold today in six metropolitan areas of the U.S.

100-Year Atmospheric Lifetime Versus 20-Year Atmospheric Lifetime

The United Nations Intergovernmental Panel on Climate Change (IPCC) developed the concept of global warming potential (GWP) as an index to help policymakers evaluate the impacts of greenhouse gases with different atmospheric lifetimes and infrared absorption properties, relative to the chosen baseline of carbon dioxide (CO₂). Scientific advancements have led to corrections in GWP values over the past decade, and it is imperative that our policy decisions reflect this new knowledge. In the mid-90s, policymakers for the Kyoto Protocol chose a 100-year time frame for comparing greenhouse gas impacts using GWPs. The choice of time horizon determines how policymakers weigh the short- and long-term costs and benefits of different strategies for tackling climate change. According to the IPCC, the decision to evaluate global warming impacts over a specific time frame is strictly a policy decision:

"the selection of a time horizon of a radiative forcing index is largely a 'user' choice (i.e. a policy decision)" [and] "if the policy emphasis is to help guard against the possible occurrence of potentially abrupt, non-linear climate responses in the relatively near future, then a choice of a 20-year time horizon would yield an index that is relevant to making such decisions regarding appropriate greenhouse gas abatement strategies."

Short-lived pollutants that scientists are targeting today are methane and hydrofluorocarbons (HFCs) which are greenhouse gases like CO₂, warming the atmosphere by trapping radiation after it is reflected from the ground. Black carbon and tropospheric ozone, an element of smog, are not greenhouse gases, but they warm the air by directly absorbing solar radiation. Black carbon remains in the atmosphere for only two weeks and methane for no more than 15 years. There is a growing scientific movement to calculate GHG emissions potential based on the short-term carbon forcing gases.

This report presents GHG emissions results for both 100-Year Atmospheric Lifetime and 20-Year Atmospheric Lifetime for impact assessments. The results of the emissions analysis are presented below for Boston. Similar detailed results are included in Appendix A for six cities that represent significant regional heating oil markets: Baltimore, MD, Boston, MA, Madison, WI, New York, NY, Norfolk, VA, and Seattle, WA. A summary of the results from all six cities is presented following the Boston results below.

Boston

100 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 18 and Figure 19 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 18, an approximately 20 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 19, which includes ILUC for biodiesel, shows that a biodiesel blend of slightly higher than 20 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback (see Table 1).



Figure 18 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Biodiesel Blends)



Figure 19 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Biodiesel Blends)

GHG emissions comparison with advanced biodiesel blends

Figure 20 and Figure 21 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.


Figure 20 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 21 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Advanced Biodiesel Blends)

GHG emissions comparison with conventional biodiesel blends

Figure 22 and Figure 23 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 22, an approximately 7 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 23, which includes ILUC for biodiesel, shows that a biodiesel blend about 8 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors (see Table 1).



Figure 22 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Biodiesel Blends)



Figure 23 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Biodiesel Blends)

Figure 24 and Figure 25 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has substantially lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors.



Figure 24 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 25 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Advanced Biodiesel Blends)

Summary Results

Tables 35 shows the comparative annual GHG emissions for providing heating and hot water services to the modelled 2,500 square foot home in all six cities for a 100-year atmospheric lifetime GWP with carbon feedback factor. The table provides the annual GHG emissions in terms of lbs CO2e/Year for a typical replacement natural gas boiler using pipeline natural gas and a typical replacement oil boiler using ultra-low-sulfur (ULS) heating oil, including energy use along the fuel cycle, end use equipment efficiency, and modelled heating loads in each city. As shown, boilers using 100% ULS heating oil release 15 to 19% more GHG emissions on an annual basis than natural gas boilers in similar service. The table also includes the annual difference in GHG emissions between natural gas and various blends of biofuel and ULS heating oil. In line with the comparison presented above for Boston, biofuel/ULS heating oil blends of 17.4 to 21.9% produce equivalent GHG emissions to natural gas. The table shows that significant annual GHG emissions savings over natural gas can be achieved as the percentage of biofuel increases. Blends up to B100⁶⁴ have been used in the field, with B20 blend being quite typical in commercial use.

	Baltimore	Boston	Madison	NYC	Norfolk	Seattle			
Natural Gas, lb CO2e/Year	16,033	18,797	25,063	17,231	11,625	15,081			
ULS Heating Oil, lb CO2e/Year	18,783	22,223	29,935	20,261	13,355	17,601			
Biofuel blend for equivalence, %	19.7%	20.7%	21.9%	20.1%	17.4%	19.2%			
Difference in Annual GHG Emissions (Heating Oil Blend Emissions – Natural Gas Emissions)									
100% ULS Htg Oil (B0), lb CO2e/Yr	2,750	3,426	4,872	3,031	1,730	2,520			
B10 Blend, lb CO2e/Yr	872	1,771	2,644	1,522	736	1,210			
B20 Blend, lb CO2e/Yr	-1,006	117	415	14	-259	-101			
B30 Blend, lb CO2e/Yr	-2,884	-1,538	-1,814	-1,495	-1,253	-1,411			
B40 Blend, lb CO2e/Yr	-4,763	-3,192	-4,043	-3,003	-2,247	-2,721			
B50 Blend, lb CO2e/Yr	-6,641	-4,847	-6,271	-4,512	-3,242	-4,032			
B60 Blend, lb CO2e/Yr	-8,519	-6,501	-8,500	-6,020	-4,236	-5,342			
B70 Blend, lb CO2e/Yr	-10,398	-8,156	-10,729	-7,529	-5,230	-6,653			
B80 Blend, lb CO2e/Yr	-12,276	-9,810	-12,957	-9,037	-6,225	-7,963			
B90 Blend, lb CO2e/Yr	-14,154	-11,465	-15,186	-10,546	-7,219	-9,273			
B100, lb CO2e/Yr	-16,033	-13,119	-17,415	-12,054	-8,213	-10,584			

Table 35 – 100 Year Atmospheric Lifetime with Carbon Feedback

Tables 36 shows the comparative annual GHG emissions for providing heating and hot water services to the modelled 2,500 square foot home in all six cities for a 20-year atmospheric lifetime GWP factor. As

⁶⁴ B100 (100% biodiesel) has been applied in the field, but very special care must be taken with respect to clod flow properties.

in the previous table, this table provides the annual GHG emissions in terms of lbs CO2e/Year for a typical replacement natural gas boiler using pipeline natural gas and a typical replacement oil boiler using ultra-low-sulfur (ULS) heating oil, including energy use along the fuel cycle, end use equipment efficiency, and modelled heating loads in each city. As shown, boilers using 100% ULS heating oil release 2 to 6% more GHG emissions on an annual basis than natural gas boilers in similar service. The table also includes the annual difference in GHG emissions between natural gas and various blends of biofuel and ULS heating oil. Based on the 20 year GWP factor, biofuel/ULS heating oil blends of 2.8 to 7.8% produce equivalent GHG emissions to natural gas. The table shows that significant annual GHG emissions savings over natural gas can be achieved as the percentage of biofuel increases. Again, blends up to B100 have been used in the field, with B20 blend being quite typical in commercial use.

	Baltimore	Boston	Madison	NYC	Norfolk	Seattle			
Natural Gas, lb CO2e/Year	18,882	22,137	29,516	20,292	13,691	17,760			
ULS Heating Oil, lb CO2e/Year	19,657	23,256	31,327	21,203	13,976	18,419			
Biofuel blend for equivalence, %	5.3%	6.5%	7.8%	5.8%	2.8%	4.8%			
Difference in Annual GHG Emissions (Heating Oil Blend Emissions – Natural Gas Emissions)									
100% ULS Htg Oil (B0), lb CO2e/Yr	775	1,119	1,811	911	285	659			
B10 Blend, lb CO2e/Yr	-681	-603	-509	-659	-750	-705			
B20 Blend, lb CO2e/Yr	-2,136	-2,325	-2,828	-2,229	-1,785	-2,069			
B30 Blend, lb CO2e/Yr	-3,591	-4,047	-5,148	-3,799	-2,819	-3,432			
B40 Blend, lb CO2e/Yr	-5,047	-5,769	-7,467	-5,369	-3,854	-4,796			
B50 Blend, lb CO2e/Yr	-6,502	-7,491	-9,787	-6,939	-4,889	-6,160			
B60 Blend, lb CO2e/Yr	-7,957	-9,212	-12,106	-8,509	-5,924	-7,524			
B70 Blend, lb CO2e/Yr	-9,413	-10,934	-14,426	-10,078	-6,958	-8,887			
B80 Blend, lb CO2e/Yr	-10,868	-12,656	-16,745	-11,648	-7,993	-10,251			
B90 Blend, lb CO2e/Yr	-12,324	-14,378	-19,064	-13,218	-9,028	-11,615			
B100, lb CO2e/Yr	-13,779	-16,100	-21,384	-14,788	-10,063	-12,979			

Table 36 - 20 Year Atmospheric Lifetime

FINDINGS

Climate change is attributed to the man-made emissions of so-called greenhouse gases (GHGs) such as carbon dioxide or methane. One of the most important environmental policy objectives of the United States and the individual states is, therefore, wide-reaching carbon neutrality in the provision of energy and raw materials. The purpose of this study is to show how liquid sources of energy can help achieve that goal in the residential heating market.

The analysis underscores the importance of considering the total resource energy use and fuel cycle emissions impacts of fuel consumption, including utilization efficiencies at the point of use, when evaluating the energy and GHG emissions of any fuel source. Significant energy is consumed, with resulting emissions of CO₂ and other greenhouse gases (GHG), during all stages of the fuel cycle including the production, processing, transmission, distribution, and ultimate combustion stages of all fuels considered.

Results from this analysis can be summarized as follows:

- It is critical to compare the energy and emissions performance of fuels in terms of the full fuelcycle and actual (as opposed to rated) efficiencies at the point of use.
- Heating oil, with modest levels of biofuel blending (20 to 25 percent), remains a competitive alternative to natural gas for residential heating in terms of overall energy use and GHG emissions based on 100-year atmospheric lifetime calculations.
- Heating oil, with even lower levels of biofuel blending (7 to 8 percent), remains a competitive alternative to natural gas for residential heating in terms of overall energy use and GHG emissions based on carbon forcing 20-year atmospheric lifetime calculations.
- The heating oil industry is actively incorporating existing biofuels into product blends in order to reduce GHG emissions, and is working with suppliers to ensure these product blends are compatible with existing and new oil heating equipment
- Advanced biofuels, such as ethyl levulinate, show even greater promise at reducing the GHG footprint of heating oil blends, well beyond the levels of competing fuels such as natural gas.

These results also lead to further implications to consider as the US and states evaluate how best to decarbonize the economy over the long term:

• Converting the existing, mainly fossil-derived, energy supply to lower GHG emissions levels will call for the use of considerable amounts of renewable energy.

- Increasing electrification and integrated energy in the transportation and heating markets would lead to significantly more electricity demand. Renewable electricity production and electricity storage would have to substantially increase (Figure 26) to meet this demand. Wind and solar are variable energy resources, and some way must be found to address the issue of how to provide energy if their immediate output cannot continuously meet instantaneous demand. The main options are to (i) curtail load (i.e., modify or fail to satisfy demand) at times when energy is not available, (ii) deploy very large amounts of energy storage, or (iii) provide supplemental energy sources that can be dispatched when needed.
- It is not yet clear how much it is possible to curtail loads, especially over long durations, without incurring large economic costs. There are no electric storage systems available today that can affordably and dependably store the vast amounts of energy needed over days or weeks to reliably satisfy demand using expanded wind and solar power generation alone. These facts have led many analysts to recognize the importance of maintaining a broad portfolio of electricity generation technologies, including low-carbon, high efficiency fossil-fueled sources, that can be dispatched when needed⁶⁵.



Figure 26 - Installed capacity values for 2015 (left column in each pair) and potential capacity required for 2050 All Renewable Grid (right column in each pair)⁶⁶

• In addition to technical limits on the sole reliance of renewable resources to meet the increased demand of economy-wide electrification, there are economic limits. The costs of expanding renewable capacity to meet this increased demand would be significant. Ultimate decarbonization of the economy will require a mix of electrification in areas where technology and costs can support such conversions, and deployment of high efficiency, low carbon fossil-fuel end-use alternatives in many other regions.

⁶⁵ Christopher T. M. Clack, et al, "Evaluation of a proposal for reliable low-cost grid power with 100% wind, water, and solar", 6722–6727, PNAS, June 27, 2017, vol. 114, no. 26

⁶⁶ These 100% wind, solar, and hydroelectric studies propose installing technologies at a scale equivalent to (or substantially greater than) the entire capacity of the existing electricity generation infrastructure. The other category includes coal, natural gas, and nuclear, all of which are removed by 2050.

• Domestic liquid fuels can continue to make a significant contribution to the national energy supply even in the future. Their high energy density makes transporting and storing them very simple and cost-efficient. As individual stocks can be kept, energy can be provided at any location whether or not there is a dedicated infrastructure. Providing liquid GHG-reduced fuels can disburden the electricity supply regarding capacity, grid stability and resilience.

APPENDIX A – DETAILED CITY COMPARISONS

Baltimore

100 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 27 and Figure 28 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Baltimore area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 27, an approximately 20 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions Figure 28, which includes ILUC for biodiesel, shows that a biodiesel blend of slightly higher than 20 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback (see Table 1).



Figure 27 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) Without ILUC (Biodiesel Blends)



Figure 28 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) With ILUC (Biodiesel Blends)

Figure 29 and Figure 30 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Baltimore area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.



Figure 29 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 30 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) With ILUC (Advanced Biodiesel Blends)

GHG emissions comparison with conventional biodiesel blends

Figure 31 and Figure 32 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Baltimore area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers using natural gas, ULS heating oil and biodiesel blends as fuels. Figure 31, an approximately 7 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 32, which includes ILUC for biodiesel, shows that a biodiesel blend about 8 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors (see Table 1).



Figure 31 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) Without ILUC (Biodiesel Blends)



Figure 32 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) With ILUC (Biodiesel Blends)

Figure 33 and Figure 34 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Baltimore area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has substantially lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors.



Figure 33 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 34 - Heating System GHG Emissions Comparison for Baltimore (2015 Data) With ILUC (Advanced Biodiesel Blends)

Boston

100 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 35 and Figure 36 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 35, an approximately 20 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 36, which includes ILUC for biodiesel, shows that a biodiesel blend of slightly higher than 20 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback (see Table 1).



Figure 35 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Biodiesel Blends)



Figure 36 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Biodiesel Blends)

Figure 37 and Figure 38 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.



Figure 37 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 38 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Advanced Biodiesel Blends)

GHG emissions comparison with conventional biodiesel blends

Figure 39 and Figure 40 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 39, an approximately 7 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 40, which includes ILUC for biodiesel, shows that a biodiesel blend about 8 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors (see Table 1).



Figure 39 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Biodiesel Blends)



Figure 40 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Biodiesel Blends)

Figure 41 and Figure 42 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Boston area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has substantially lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors.



Figure 41 - Heating System GHG Emissions Comparison for Boston (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 42 - Heating System GHG Emissions Comparison for Boston (2015 Data) With ILUC (Advanced Biodiesel Blends)

Madison

100 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 43 and Figure 44 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Madison area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 43, an approximately 20 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 44, which includes ILUC for biodiesel, shows that a biodiesel blend of slightly higher than 20 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback (see Table 1).



Figure 43 - Heating System GHG Emissions Comparison for Madison (2015 Data) Without ILUC (Biodiesel Blends)



Figure 44 - Heating System GHG Emissions Comparison for Madison (2015 Data) With ILUC (Biodiesel Blends)

Figure 45 and Figure 46 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Madison area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.



Figure 45 - Heating System GHG Emissions Comparison for Madison (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 46 - Heating System GHG Emissions Comparison for Madison (2015 Data) With ILUC (Advanced Biodiesel Blends)

GHG emissions comparison with conventional biodiesel blends

Figure 47 and Figure 48 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Madison area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 47, an approximately 7 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 48, which includes ILUC for biodiesel, shows that a biodiesel blend about 8 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors (see Table 1).



Figure 47 - Heating System GHG Emissions Comparison for Madison (2015 Data) Without ILUC (Biodiesel Blends)



Figure 48 - Heating System GHG Emissions Comparison for Madison (2015 Data) With ILUC (Biodiesel Blends)

Figure 49 and Figure 50 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Madison area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has substantially lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors.



Figure 49 - Heating System Energy Comparison for Madison (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 50 - Heating System GHG Emissions Comparison for Madison (2015 Data) With ILUC (Advanced Biodiesel Blends)

New York City

100 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 51 and Figure 52 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the New York City area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 51, an approximately 20 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 52, which includes ILUC for biodiesel, shows that a biodiesel blend of slightly higher than 20 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback (see Table 1).



Figure 51 - Heating System GHG Emissions Comparison for New York City (2015 Data) Without ILUC (Biodiesel Blends)



Figure 52 - Heating System GHG Emissions Comparison for New York City (2015 Data) With ILUC (Biodiesel Blends)

Figure 53 and Figure 54 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the New York City area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.



Figure 53 - Heating System GHG Emissions Comparison for New York City (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 54 - Heating System GHG Emissions Comparison for New York City (2015 Data) With ILUC (Advanced Biodiesel Blends)

GHG emissions comparison with conventional biodiesel blends

Figure 55 and Figure 56 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the New York City area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 55, an approximately 6 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 56, which includes ILUC for biodiesel, shows that a biodiesel blend about 7 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors (see Table 1).



Figure 55 - Heating System GHG Emissions Comparison for New York City (2015 Data) Without ILUC (Biodiesel Blends)



Figure 56 - Heating System GHG Emissions Comparison for New York City (2015 Data) With ILUC (Biodiesel Blends)

Figure 57 and Figure 58 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the New York City area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has substantially lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors.



Figure 57 - Heating System GHG Emissions Comparison for New York City (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 58 - Heating System GHG Emissions Comparison for New York City (2015 Data) With ILUC (Advanced Biodiesel Blends)

Norfolk

100 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 59 and Figure 60 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Norfolk area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 59, an approximately 20 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 60, which includes ILUC for biodiesel, shows that a biodiesel blend of slightly higher than 20 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback (see Table 1).



Figure 59 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) Without ILUC (Biodiesel Blends)



Figure 60 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) With ILUC (Biodiesel Blends)

Figure 61 and Figure 62 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Norfolk area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.



Figure 61 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 62 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) With ILUC (Advanced Biodiesel Blends)
20 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 63 and Figure 64 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Norfolk area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 63, an approximately 7 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 64 which includes ILUC for biodiesel, shows that a biodiesel blend about 8 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors (see Table 1).



Figure 63 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) Without ILUC (Biodiesel Blends)



Figure 64 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) With ILUC (Biodiesel Blends)

GHG emissions comparison with conventional biodiesel blends

Figure 65 and Figure 66 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Norfolk area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has substantially lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors.



Figure 65 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 66 - Heating System GHG Emissions Comparison for Norfolk (2015 Data) With ILUC (Advanced Biodiesel Blends)

Seattle

100 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 67 and Figure 68 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Seattle area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 67, an approximately 20 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 68, which includes ILUC for biodiesel, shows that a biodiesel blend of slightly higher than 20 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback (see Table 1).



Figure 67 - Heating System GHG Emissions Comparison for Seattle (2015 Data) Without ILUC (Biodiesel Blends)



Figure 68 - Heating System GHG Emissions Comparison for Seattle (2015 Data) With ILUC (Biodiesel Blends)

GHG emissions comparison with advanced biodiesel blends

Figure 69 and Figure 70 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Seattle area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 100-year atmospheric lifetime global warming potential (GWP) factors with carbon feedback.



Figure 69 - Heating System GHG Emissions Comparison for Seattle (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 70 - Heating System GHG Emissions Comparison for Seattle (2015 Data) With ILUC (Advanced Biodiesel Blends)

20 Year Atmospheric Lifetime

GHG emissions comparison with conventional biodiesel blends

Figure 71 and Figure 72 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Seattle area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using natural gas, ULS heating oil and biodiesel blends as fuels. As shown in Figure 71, an approximately 6 percent biodiesel blend is equivalent to natural gas emissions, not including ILUC emissions. Figure 72, which includes ILUC for biodiesel, shows that a biodiesel blend about 7 percent is required for equivalence with natural gas. Both of these graphs show that increasing biodiesel blend content significantly improves GHG emission compared to natural gas. These results are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors (see Table 1).



Figure 71 - Heating System GHG Emissions Comparison for Seattle (2015 Data) Without ILUC (Biodiesel Blends)





GHG emissions comparison with advanced biodiesel blends

Figure 73 and Figure 74 illustrate the total annual GHG emissions from providing heating and hot water services to the modeled 2,500 square foot house in the Seattle area (including energy use along the fuel cycle and end use equipment efficiency) for typical replacement boilers being sold today using a blend of ULS heating oil, biodiesel and ethyl levulinate (advanced biofuel) as fuel. A blend of just 10% biodiesel, 10% ethyl levulinate and 80% ULSD has substantially lower annual GHG emissions than natural gas, regardless of ILUC. Both of these graphs show that increasing biodiesel and ethyl levulinate blend content significantly improves GHG emission compared to natural gas. In fact, because of the feedstock used, production techniques and multiple usable products, ethyl levulinate actually allows the potential for reduction of GHG beyond a neutral point. These graphs are based on GHG emissions using the 20-year atmospheric lifetime global warming potential (GWP) factors.



Figure 73 - Heating System GHG Emissions Comparison for Seattle (2015 Data) Without ILUC (Advanced Biodiesel Blends)



Figure 74 - Heating System GHG Emissions Comparison for Seattle (2015 Data) With ILUC (Advanced Biodiesel Blends)

APPENDIX B – CRITERIA POLLUTANTS

Criteria Pollutants Emissions

The primary criteria pollutants of combustion of natural gas and heating oil are oxides of nitrogen (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs - unburned or partially burned non-methane hydrocarbons), oxides of sulfur (SO_x) and particulate matter (PM). The level of criteria pollutant emissions can be a function of both the combustion process and the fuel type. The emissions of CO and VOCs are a function of combustion efficiency and generally are comparable for natural gas and heating oil. NO_x emissions are a function of combustion conditions such as peak flame temperature (thermal NO_x) and the conversion of chemically bound nitrogen in the fuel (fuel NO_x). Heating oil tends to have slightly higher NOx emissions than natural gas, primarily due to small amounts of fuel-bound nitrogen that is part of certain organic components in the fuel. Emissions of sulfur compounds, primarily SO₂, and particulate matter are directly related to the sulfur content of the fuel, which normally has been a disadvantage for heating oil. While combustion of heating oil traditionally has had higher emissions of NO_x, SO_x and PM than natural gas, the introduction of ultra-low sulfur heating oil and advances in burner technology have resulted in comparable emissions for ULS heating oil and natural gas.

SO₂ and Particulate Emissions

Emissions released by the combustion of many fuels—including heating oil— include tiny airborne particles, the majority of which are sulfates. Sulfates contribute to some of the most harmful air and environmental impacts, many of which also lead to a deterioration of public health. The sulfur in any fuel results in sulfur oxides being released into the atmosphere when it is burned. During combustion in residential heating systems, roughly 98-99% of the sulfur in the fuel is oxidized to form sulfur dioxide (SO₂) and emitted from the stack. Brookhaven National Laboratory testing⁶⁷ shows that changing to lower sulfur content fuel (500 ppm) eliminates about 75-80 percent of the sulfur dioxide emissions from residential oil heating systems. Ultra-low sulfur heating oil fuels (15ppm) produce immeasurable amounts of sulfur dioxides in the flue stack, similar to natural gas.

One of the most significant transitions in heating oil has been the move to ultra-low sulfur heating oil. This fuel lowers maintenance, improves efficiency and reduces pollution from heating systems. However, it is also paving the way for the next generation of equipment, which may mean lower cost materials and more compact boilers and furnaces.

In the context of residential fuel oil heating, sulfur dioxide in a heating system's flue products contributes to secondary fine particulate formation in the upper atmosphere by means of

⁶⁷ Proceedings of the 2002 National Oilheat Research Alliance technology Symposium, BNL report 52670, August 2002, Paper No. 02-13, Assessing PM2.5 Emissions from Distillate Fuel Oil Heating, S. Win Lee, I He, T. Herage, E. Kelly and B. Young, CANMET Energy Technology Center-Ottawa, Natural resources Canada

photochemistry driven by sunlight. The fine particulate (PM_{2.5}) emissions for the liquid fuel fired heating systems demonstrate the very strong linear relationship between the fine particulate emissions and the sulfur content of the liquid fuels being studied as illustrated in Figure 75 which clearly shows the linear relationship between the measured mass of fine particulates per unit of energy, expressed as milligrams per Mega-Joule (mg/MJ) versus the varying sulfur contents of four different liquid heating fuels. The fuels included a typical ASTM No. 2 fuel oil with sulfur below 0.5 percent (1,520 average ppm sulfur), an ASTM No. 2 fuel oil with sulfur content (5,780 ppm sulfur), low sulfur heating oil (322 ppm sulfur) and an ULSHO fuel (11 ppm sulfur). These results show that as sulfur decreases, the PM_{2.5} emissions are reduced in a linear manner within the sulfur content range tested. In ULS heating oil (15 ppm sulfur) the amount of PM_{2.5} was reduced dramatically to an average of 0.043 mg/MJ.



Figure 75 - PM 2.5 for Heating Oil Boilers and Furnaces with Varying Sulfur Content⁶⁸

Based on testing performed by Brookhaven National Laboratory,

Figure 76 shows that PM 2.5 emissions from Ultra Low Sulfur heating oil are on the same order of magnitude as natural gas⁶⁹.

 ⁶⁸ "Evaluation of Gas, Oil and Wood Pellet Fueled Residential Heating System Emissions Characteristics", Brookhaven National laboratory, December 2009, BNL-91286-2009-IR
⁶⁹ Ibid



Figure 76 - Comparison of Average PM2.5 for Five Heating Fuel Types for Hydronic Boilers and Warm Air Furnaces

NO_x Emissions

Nitrogen oxides (NO_x) includes both NO and NO₂ and are pollutant emissions from all combustion sources. NO_x is a concern nationally, mainly because it combines with hydrocarbons in the atmosphere and, under the influence of sunlight, forms ozone. With conventional yellow flame systems, the NO_x emissions depend upon the firing rate and the combustion chamber. Higher firing rates and increased refractory lining in the combustion chamber (hotter chamber) tend to produce higher flame temperatures and higher NO_x. Current U.S. systems range from roughly 75 ppm to 180 ppm. Arguably, 110 ppm is about the average for oil combustion with yellow flame burners.

Low-NOx residential oil burners based on high rates of recirculation of combustion products within the combustion chamber are available today. These burners have higher air velocity, and more of the air is introduced to the flame zone along the burner centerline, flame tubes to control recirculation, and flame tube slots or holes which control the amount and location of the recirculated flue gas. With these burners, achievable NOx emissions range from 40 to 65 ppm.

It is technically feasible to achieve NOx emissions under 10 ppm with a nitrogen free fuel. Routes which have been developed towards achieving this goal include: 1) Increased recirculation rates with current low-NOx burner designs with special provisions for startup; 2) new burner head designs; and 3) oil vaporization followed by combustion in radiant, porous media⁷⁰.

⁷⁰ NOx burner assessment from Dr. Thomas Butcher, Director of Brookhaven National Laboratory's Energy Resources Division