Introducing a Low Carbon Fuel Standard in the Northeast

Technical and Policy Considerations

Prepared by
NESCCAF
Northeast States Center for a Clean Air Future

July, 2009

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Acknowledgments

NESCCAF gratefully acknowledges the generous support provided by the Energy Foundation and by the William and Flora Hewlett Foundation for this research. NESCCAF appreciates the thoughtful input provided by the Research Advisory Group established as part of the Low Carbon Fuel Standard project. The Advisory Group provided input while the analyses for this project were being conducted and during the development of this report. Members of the Advisory Group include: Anthony Eggert (California Air Resources Board), Rebecca Ohler (New Hampshire DES), Robert Judge (USEPA), Carl Mas (New York State Energy Research & Development Authority), Christina Zhang-Tillman (CARB), Daniel Sperling (University of California-Davis), Dean Simeroth (CARB), Ellen Shapiro (Alliance of Automobile Manufacturers), Eric Kingsley (Innovative Natural Resource Solutions), John Gorgol (New Jersey DEP), Nancy Seidman (Massachusetts DEP), Nathanael Greene (Natural Resources Defense Council), Dr. Roger L. Leisenring, Jr. (Sunoco), Serpil Guran (New Jersey DEP), Sonia Yeh (UC Davis), Dr. Stephen Shaler (University of Maine), Steven Levy (Sprague Energy), William Space (Massachusetts DEP), Ryan Katofsky (Independent Consultant), Aimee Powelka (Massachusetts DEP), Dr. Steven Hamburg (Brown University), and Carolyn Green (Sunoco – now with EnerGreen Capital Management).

NESCCAF would also like to thank the NESCAUM Mobile Source Committee and the NESCCAF Directors for their assistance during this project. In addition, NESCCAF gratefully acknowledges the individuals who reviewed drafts of the technical documents and the final report for this project. Among them, we especially thank Anant Vyas from Argonne National Laboratory who reviewed a draft of the VISION-NE model for NESCCAF. Dr. Marc Melaina (UC Davis), Luke Tonachel (NRDC), and Bill Boyce (Sacramento Municipal Utility District) who provided advice and valuable input on the scenario analysis program structure. Finally, NESCCAF alone is responsible for all conclusions and recommendations, as well as any errors or omissions found in this report.

Printed: September 2009

ERRATA SHEET

Updated: September 15, 2009

Executive Summary, Table ES-2:

Type of Low Carbon Fuel	2010	Equivalent Gallons of gasoline or diesel (millions)	2020	Equivalent Gallons of gasoline or diesel (millions)
Electricity (MW)	849	200/600*	1,524	360/1,080*
Cellulosic ethanol (millions of gallons)	--	--	440	290
Thermal energy (no. of homes heated)	400,000	250	1,000,000	630
Neat biodiesel (millions of gallons)	~~8.3~~ 6.6	~~7.7~~ 6.1	~~8.5~~ 6.7	~~7.8~~ 6.2

3.1. Assumptions and Limitations of Analysis

Their usefulness in complying with an LCFS depends on many of the same unknowns regarding grid mix, vehicle specifications, and user behavior that apply to light-duty EVs and PHEVs, as discussed in section ~~3.1.6~~ 3.4.

5.5. Chapter Summary:

Nearly 7 million gallons of neat biodiesel could be produced from over 30,000 tons of likely available waste cooking oils in 2020 (assuming only the use of 10 percent of maximum available "yellow" grease).~~,~~ This is enough for ~~170~~ 134 million gallons of B5 biodiesel blend.~~ This could displace xx percent of transportation diesel demand in the region.~~

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Low Carbon Fuel Standards Glossary

AEO:	Annual Energy Outlook
AER:	All-Electric Range
AFCI:	Average Fuel Carbon Intensity
BBL:	Barrels
BD:	Biodiesel
BEV:	Battery-powered Electric Vehicle
BIGCC:	Biomass Integrated Gasification Combined Cycle
BTU:	British Thermal Unit
CARB:	California Air Resources Board
CARBOB:	California Reformulated Blendstock for Oxygenate Blending
C&D:	Construction & Demolition
CBOB:	Conventional Blendstock for Oxygenate Blending
CD:	Conventional Diesel
CEC:	California Energy Commission
CG:	Conventional Gasoline
CH_4:	Methane
CHP:	Combined Heat and Power
CI:	Carbon Intensity
CNG:	Compressed Natural Gas
CO_2:	Carbon Dioxide
CO_2e:	Carbon Dioxide Equivalent
EER:	Energy Economy Ratio
eGRID:	Emissions & Generation Resource Integrated Database
EIA:	Energy Information Administration
EISA:	Energy Independence and Security Act
EPA:	United States Environmental Protection Agency
EPRI:	Electric Power Research Institute
EtOH:	Ethanol
EV:	Electric Vehicle
FAME:	Esterfied Biodiesel
FERC:	Federal Energy Regulatory Commission
FFV:	Flexible Fuel Vehicles
GHG:	Greenhouse Gas
GTAB:	Gasoline Treated as Blendstock
GW:	Gigawatt
GWh:	Gigawatt Hour
GWI:	Global Warming Intensity
HD:	Heavy Duty
HHO:	Home Heating Oil
HHV:	High Heating Value
IEA:	International Energy Agency
IFEU:	Institute for Energy and Environmental Research
INRS:	Integrated Natural Resource Solutions, LLC

IWSA:	Integrated Waste Services Association
LCA:	Life Cycle Analysis
LCFS:	Low Carbon Fuel Standards
LD:	Light Duty
LDV:	Light Duty Vehicle
LEV:	Low Emission Vehicles
LHV:	Low Heating Value
LNG:	Liquefied Natural Gas
LPG:	Liquefied Petroleum Gas
LUC:	Land Use Change
MJ:	Megajoule
MPGGE:	Miles Per Gallon – Gallon Equivalent
MSW:	Municipal Solid Wastes
M*t*BE:	Methyl *tertiary*-Butyl Ether
MW:	Megawatt
N_2O:	Nitrous Oxide
NA:	North American
NBAP:	National Biodiesel Accreditation Program
NE:	North Eastern
NEG/ECP:	Conference of New England Governors and Eastern Canadian Premiers
NERC:	North American Electricity Reliability Council
NERD:	Non-esterfied Renewable Biodiesel
NESCAUM:	Northeast States for Coordinated Air Use Management
NESCCAF:	Northeast States for a Clean Air Future
NESHAP:	National Emissions Standards for Hazardous Air Pollutants
NMOG:	Non-Methane Organic Compounds
NRDC:	National Resource Defense Council
NREL:	National Renewable Energy Laboratory
OBD:	On-Board Diagnostic
OSW:	Oriented Strand Board
OWB:	Outdoor Wood Boiler
PADD:	Petroleum Administration for Defense District
PDEP:	Pennsylvania Department of Environmental Protection
PHEV:	Plug-in Hybrid Electric Vehicle
PJM:	PJM Interconnection Consulting
PPM:	Parts Per Million
RBOB:	Reformulated Blendstock for Oxygenate Blending
RD&D:	Research, Development & Deployment
RFA:	Renewable Fuels Association
RFG:	Reformulated Gasoline
RFS:	Renewable Fuel Standard
RFS2:	Updated Renewable Fuel Standard
RGGI:	Regional Greenhouse Gas Initiative
RIN:	Renewable Identification Number
RPS:	Renewable Portfolio Standards
RTFO:	Renewable Transport Fuel Obligation

SERC:	Southeastern Electricity Reliability Council
TTW:	Tank-to-Wheel
UBA:	Umweltbundesamt (Germany Federal Environment Agency)
ULSD:	Ultra-low-sulfur Diesel
USDA:	United States Department of Agriculture
V2G:	Vehicle-to-Grid
VMT:	Vehicle Miles Traveled
WTT:	Well-to-Tank
WWTF:	Wastewater Treatment Facility
ZEV:	Zero Emissions Vehicle

Preface

This report by the Northeast States Center for a Clean Air Future (NESCCAF) is the result of a year-long study of a Low Carbon Fuel Standard (LCFS), a performance-based program designed to reduce greenhouse gas (GHG) emissions from fuels. The primary goal of NESCCAF's effort, conducted on behalf of 11 northeastern states, was to explore how such a program might be implemented in the Northeast. Specifically, our analysis sought to identify and provide information on key factors for the states' consideration in the development of a regional LCFS. These key factors include the role of locally sourced feedstocks and low carbon fuels; the current structure of the region's fuel industry and potential regulated entitities; and, possible interactions of a regional LCFS with other programs such as the federal Renewable Fuel Standard. While this study hopefully provides many insights into the development and implementation of a regional LCFS, the states themselves will direct LCFS policy.

This study also provides initial calculations of various illustrative scenarios for compliance with a regional LCFS, based upon the best available research available at the time of writing. It is worth noting that the GHG impacts of feedstocks and fuels are currently the focus of significant research and policy discussions around the world. As a result, it was not possible to incorporate all recent relevant scientific results into this study, so all findings of this analysis should be viewed as initial rather than final estimates.

Finally, NESCCAF's analysis could not address all of the potentially complex policy issues associated with LCFS implementation, such as the sustainability of feedstocks and fuels, or the potential economic impacts of a regional LCFS. NESCCAF and the 11 state governments continue to work together and with stakeholders on additional analyses of these issues and plan to make further refinements to our analytic tools as more information becomes available.

Executive Summary

Overview

NESCCAF has undertaken a preliminary assessment of a low carbon fuel standard (LCFS) for the New England and Mid-Atlantic states.[1] As part of this assessment, NESCCAF estimated the amount of low carbon fuels that would be needed to meet an LCFS in the Northeast, evaluated the potential to generate low carbon fuels using resources sourced from the region, and explored program implementation strategies and issues. The results are presented in this report, which is intended to inform the region's policymakers as they evaluate programs and options for reducing greenhouse gas (GHG) emissions from the transportation sector.

Transportation-related GHG emissions account for a large share - about 40 percent - of total anthropogenic emissions in the Northeast. Since passenger car and heavy-truck miles are projected to increase steadily in coming decades, as is activity from nonroad machines and vehicles, transportation sources also represent one of the fastest growing sectors of the GHG inventory (EPA 2009). The northeastern states have all committed to reducing GHG emissions that contribute to climate change and as such have a keen interest in addressing emissions from transportation sources.

The Northeast has significant capacity to generate low carbon fuels from resources sourced in the region. In addition to the potential for in-region production of low carbon fuels, the federal Renewable Fuels Standard (RFS) is spurring research and development into advanced biofuels, which could result in substantial volumes of low carbon fuels. On the automotive technology front, automobile manufacturers are proceeding with production of advanced vehicles that could facilitate the widespread use of some low carbon fuels. Assuming: (1) aggressive deployment of low carbon fuels and feedstocks from the region to reduce emissions from transportation sources; (2) aggressive deployment of advanced automotive technologies; and (3) production of advanced biofuels from outside of the region - the study finds that GHG emissions associated with the use of transportation fuels in the region could be greatly reduced over the next decade.

Background:

Nearly all of the northeastern states have established targets for reducing GHG emissions. These targets vary state-to-state, but generally require a 20 percent reduction in total anthropogenic GHG emissions by 2020 from 1990 levels and a 50 percent or greater reduction from 1990 levels by 2050. To meet these targets, substantial reductions in transportation GHG emissions will be needed. There are three approaches to achieving GHG reductions in the transportation sector: (1) reduce vehicle GHG emissions; (2) reduce travel demand and slow the growth of "vehicle miles traveled" (VMT); and, (3) change the properties of transportation fuel.

A low carbon fuel standard targets the latter approach of changing a fuel's GHG characteristics and seeks to reduce the GHG emissions associated with each unit of energy

[1] The New England states include: Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island. The mid-Atlantic states include: New York, New Jersey, Pennsylvania, Delaware, and Maryland. Hereafter in this report, these two regions together are referred to as "the Northeast."

produced by a given fuel on a lifecycle basis. This requires accounting for emissions from all aspects of a fuel's lifecycle, including cultivation or extraction, production, processing, transport, delivery, and combustion. An important feature of an LCFS is that it is designed to reduce the *intensity* of GHG emissions from fuels on a per unit basis, rather than to cap transportation emissions in an absolute sense. For this reason, an LCFS is most effective when deployed in conjunction with complementary state and regional policies such as the Low Emission Vehicle (LEV) program, VMT reduction strategies, and policies aimed at the electricity sector such as cap-and-trade, energy efficiency, and renewable portfolio standards (RPS).[2] All of these complementary programs are already in existence across the region.

The LCFS is a performance-based regulation that sets a target for lowering the carbon intensity of fuels and allows the market to determine the most cost-effective fuels and strategies for achieving that target. This feature encourages further technological innovation in a sector that is already undergoing rapid transformation. In the early years of an LCFS, compliance will likely result from greater use of low carbon fuels that are currently available, such as biodiesel, wood and waste-based biomass, and certain types of ethanol. As a performance standard, an LCFS also encourages investment in the development of a variety of low carbon fuels and related technologies that are not yet commercially viable, because advanced fuel technologies will be essential for LCFS compliance over the longer term.

Importantly, an LCFS can also protect against the potential for transportation fuels to become *more* carbon intensive. For example, greater use of fuels derived from tar sands, some biofuels, and fuels generally thought of as climate-friendly – such as hydrogen – when produced in carbon intensive ways (for example, using coal without carbon capture and storage) could increase carbon emissions from transportation fuels.

The California Air Resources Board approved an LCFS program that requires a 10 percent reduction by 2020 in the GHG-intensity of transportation fuels. In the Northeast, an opportunity for additional GHG mitigation exists if the LCFS includes in its scope fuels used for space heating (e.g., No. 2 distillate fuel oil used widely throughout the region).[3] Finally, a low carbon fuel program has the potential to provide important economic and energy security benefits in the Northeast. Nearly all transportation fuel and much of the heating fuel used in the region are imported, which results in a significant outflow of capital from the regional economy. As stated above, this study concludes that substantial amounts of low carbon fuel may be manufactured from resources indigenous to the Northeast. A shift toward indigenous sources of fuel can provide jobs and ensure that resources are retained in the regional economy.

For the above stated reasons, states in the region are considering the development of LCFS program. Given that the LCFS is different from other regulatory programs

[2] In 2009, the Northeast implemented the Regional Greenhouse Gas Initiative (RGGI), the first CO_2 cap-and-trade program for electricity generators in the US. In addition, 9 of the 11 states in the region considering the LCFS have adopted the California motor vehicle GHG standards which will reduce new vehicle GHG emissions by 30 percent.

[3] Throughout this report, we use the term "heating oil" to refer to distillate fuel oil used for heating purposes. Heating oil generally includes No. 2 distillate oil and a small percentage of No. 6 fuel oil, which is used on a much more limited basis than No. 2. For a more detailed description of the use of heating oil in the Northeast, refer to Appendix C.

implemented to date, the NESCCAF study goal was to clarify aspects of the technical and policy issues associated with adoption and implementation of the LCFS for states considering the program.

Key Findings for Policy Makers

Below are NESCCAF's key findings from this analysis.

- An LCFS requiring a 10 percent reduction in the carbon intensity of fuel by 2020 in the Northeast would result in 30 million tons of GHGs reduced annually compared to business-as-usual projections. These reductions would be comparable to the GHG reductions that will result from the implementation of California's motor vehicle GHG standards in the region, and higher than those from the Regional Greenhouse Gas Initiative (RGGI) cap-and-trade program on power plants. As such, the LCFS, if implemented, would be a cornerstone of the region's approach to reduce transportation-related GHG emissions.
- Successful implementation of a 10 percent LCFS will require very rapid commercialization of advanced fuels and/or advanced technology vehicles that are presently in the pre-commercial stage. While the outlook for these technologies is promising, the volumes that would be required in order to meet a 10 percent LCFS by 2020 greatly exceed the volumes that have been produced to date.
- Technologies that could potentially be used to reduce average fuel carbon intensity include advanced low carbon biofuels such as cellulosic ethanol, and biomass-based diesel, and vehicles powered in part or entirely by electricity.
- If the LCFS is met solely with the most advanced type of biofuel required under the federal RFS (cellulosic ethanol with a carbon intensity of 60 percent lower than that of gasoline,) it would require approximately 4 billion gallons to meet a 10 percent reduction target in the Northeast region by 2020. To put this in context, the federal RFS as proposed will require nationwide production of 10.5 billion gallons of cellulosic ethanol with an equivalent carbon intensity in 2020.
- If the LCFS gasoline carbon intensity reduction were to be met through the use of cars powered in part or entirely by electricity, approximately 3 million plug-in hybrid and all-electric vehicles would need to be in the Northeast vehicle fleet by 2020. Assuming these vehicles are charged when sufficient capacity and transmission exist, the region's electric grid could likely accommodate them without the need for additional capacity. The Zero Emission Vehicle program when implemented could result in the placement of approximately 500,000 plug-in hybrid vehicles in the region by 2020.
- Assuming the federal Renewable Fuels Standard is implemented as proposed, it will result in a reduction of approximately 3 percent in lifecycle GHG emissions from gasoline in the Northeast and approximately 1 percent in lifecycle GHG emissions from diesel fuel. This assumes advanced fuels

required under the RFS are distributed throughout the United States in volumes proportional to population.

- The Renewable Portfolio Standards require a percentage of electricity generating capacity to come from renewable energy. RGGI requires a reduction in total GHG emissions from electricity plants. These two programs, when fully implemented, will reduce the carbon intensity of electricity in the Northeast region.
- Resources sourced from the region could provide feedstocks for the production of advanced biofuels or for electricity generation. Waste is by far the region's most significant resource and taking into consideration the above statement, waste could be used to produce fuels for transportation or to generate electricity. A significant amount of waste biogas can also be produced in the region. In addition to waste biomass and biogas, NESCCAF conservatively estimates that over 6 million dry tons of woody and agricultural biomass are likely available in the Northeast annually.[4]
- If waste-based biomass, biogas, and woody and agricultural biomass from the region were used to generate electricity, approximately 1,500 MW of electricity generating capacity could be created. To put this in context, the electricity generated from these resources would be equivalent to the electricity needed to charge more than 1.5 million electric vehicles in the region.
- Woody biomass can also be used as a replacement fuel for heating oil. Some types of waste and woody biomass could also be used as feedstock for liquid transportation fuels.
- Simultaneous implementation of LCFS, RPS and RGGI is likely to result in economic competition for regional feedstocks. As a result, availability of waste and biomass for low carbon fuel production will vary depending on competing markets for these resources, environmental concerns, landowner preferences, and public policies.
- Recent research has highlighted the risk that increasing demand for biofuels from the U.S. and elsewhere may create pressure on markets for land that then encourages clearing of forests, which are important stores of carbon. Using regional resources, such as electricity, municipal solid waste, and woody and agricultural biomass, that are not currently being used in existing markets may mitigate the risk of inducing further land use change and potentially increasing lifecycle GHG emissions of fuels.
- Lifecycle GHG emissions must be calculated using consistent methodology from state to state and from region to region in order to provide strong market signals and certainty for regulated entities. Lifecycle emissions must include

[4] For the purposes of this report, *likely available biomass* refers to woody biomass from forest and mill residues, new forest growth, some urban wood wastes, agricultural residues and biomass grown on some marginal lands.

direct emissions associated with all stages of fuel extraction, production, transportation, and use. In addition, lifecycle emissions must include indirect emissions such as those resulting from the clearing of forest to grow feedstocks since studies have shown the risk of significant GHG impacts from indirect land use change.

- State programs within the region should be consistent in terms of the stringency of their reduction targets given the fungible nature of the region's gasoline and diesel fuel.
- All transportation fuels should be included in the LCFS, with the exception of bunker fuel, for which standards are set at the international level, and aviation fuel.

The remainder of this Executive Summary provides summaries of the analyses of LCFS compliance scenarios, low carbon fuel production using regional resources, and program design and implementation issues. These summaries are followed by next steps and conclusions.

Summary of Scenario Analysis

To estimate the amount of low carbon fuel that would be needed to achieve a 10 percent reduction in the carbon intensity of both gasoline and diesel in the region and to assess various compliance pathways, NESCCAF customized Argonne National Laboratory's VISION model. The model predicts the amounts of various fuels that could be used to comply with a Northeast LCFS. While the states in the region have not selected a carbon intensity reduction target, this study has used a 10 percent standard for analysis purposes.

As discussed above, a 10 percent reduction in fuel carbon intensity might be achieved in part by using advanced biofuels with very low lifecycle GHG emissions, such as cellulosic ethanol, biodiesel derived from algae, and fuels derived from municipal solid waste. Another approach would be to displace liquid fuels with substitutes such as electricity generated from low carbon sources to power plug-in hybrid and all-electric vehicles. NESCCAF evaluated a number of different compliance scenarios for both gasoline and diesel fuel. Two of these scenarios are shown below. These are hypothetical examples intended only to illustrate how a low carbon fuel standard might be met. Many other strategies may also achieve a given reduction target. The example scenarios are not meant as an endorsement of any preferred compliance pathway.

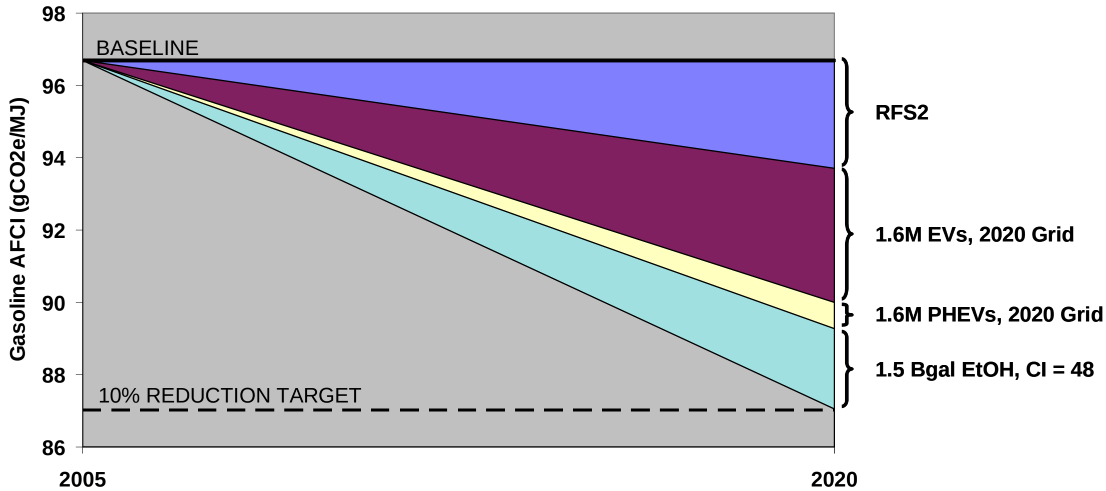


Figure ES-1. Example Gasoline Scenario Assuming Advanced Biofuels and Electric Vehicles

The scenario shown in Figure ES-1 illustrates a compliance pathway based on the substitution of gasoline-powered cars with advanced biofuels and partial or all-electric vehicles. In this example, 4 percent of the light-duty fleet is composed of electric vehicles (EV) and 4 percent of the light-duty fleet is composed of plug-in hybrid-electric vehicles (PHEV). It also assumes the introduction of 1.5 billion gallons of advanced biofuels, beyond the 1.5 billion gallons expected from the federal RFS in the Northeast by 2020. The scenario relies on an aggressive, but potentially feasible penetration of electric and plug-in hybrid vehicles starting in 2010 and the availability of advanced biofuels in quantities in excess of those required by the RFS.

For the heavy-duty diesel vehicle fleet, NESCCAF analyzed the amount of different types of low carbon fuel that would be needed to achieve a 10 percent reduction in overall fuel carbon intensity. One scenario is shown in Figure ES-2.

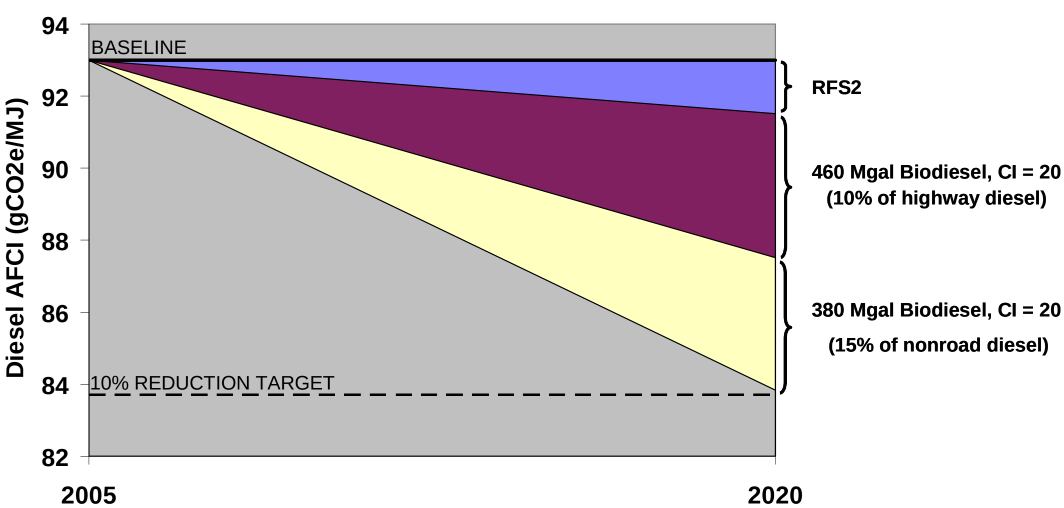


Figure ES-2. Example Diesel Scenario Assuming Advanced Biodiesel

This scenario assumes the federal RFS will result in the delivery of 240 million gallons of advanced biodiesel in the Northeast with a carbon intensity 50 percent lower than conventional diesel fuel in 2020. This by itself provides a 1 percent reduction in average diesel carbon intensity. This scenario further assumes that 10 percent of highway diesel and 15 percent of nonroad diesel will be displaced by advanced biodiesel that is 80 percent less carbon intensive than conventional diesel fuel. Other potential compliance scenarios for gasoline and diesel are presented in the *Scenario Analysis* described in Chapter 3.

The above scenarios show that substantial volumes of advanced biofuels or substantial numbers of advanced technology vehicles, or both will be needed to meet the LCFS. These assumptions are very optimistic, but plausible given increases in production capacity of advanced biofuels anticipated from the RFS, plans by automobile manufacturers to produce advanced technology vehicles, and regionally available low carbon fuels and fuel feedstocks.

Program Structure

The California Air Resources Board (CARB) has established a regulatory structure for its LCFS that identifies regulated entities, a method for estimating carbon intensity of fuels, reporting requirements, and enforcement procedures. Many of these program elements could be used as a template by the northeast and mid-Atlantic states. NESCCAF has identified elements that define how an LCFS program, if adopted, could be implemented in the Northeast.

Role of Non-Liquid Fuels: There is significant potential for non-liquid fuels to partially replace traditional, petroleum-based fuels as one key element of an LCFS. In the transportation sector, electricity can be used to power hybrid-electric or fully electric vehicles. Natural gas may also have an increased role as an alternative vehicle fuel. In thermal applications, geothermal heat, wood pellets, natural gas, and other fuels could displace fuel used for space heating, should the states include No. 2 fuel used in space heating in the LCFS. An LCFS program could include mechanisms to encourage penetration of these alternative energy sources into sectors where their potential has yet to be fully realized. This would necessitate mechanisms for quantifying the use of non-liquid fuels to be established. In the case of fuels used in California (such as electricity), the mechanism developed by CARB could be used in the Northeast. In the case of fuels not used in California – such as fuels for space heating – the Northeast would need to develop its own mechanism for quantifying conventional and low carbon fuel use.

Maintaining consistency within the region: Given the fungible nature of transportation fuels and the relatively small geographic area of each of the northeast states, state programs should strive for consistency across the region with regard to lifecycle emissions accounting, program stringency, and the implementation schedule for the LCFS.

Including heating oil in the LCFS: In the Northeast, heating oil is used in substantial quantities and is often distributed through the same network as nonroad diesel fuel. An approach the states might consider would be to include heating oil in a low carbon fuel program in the same timeframe as transportation fuel. Alternatively, carbon intensity reductions in heating oil might not be required and the displacement of heating oil by less carbon intensive alternatives could be used to generate credits toward compliance with an

LCFS aimed at the transportation sector. Other approaches to including or excluding heating oil in the LCFS are discussed in more detail in Chapter 4.

Analysis of Regional Low Carbon Fuel Supply

As part of this study, NESCCAF analyzed the volume of low carbon fuels that could potentially be produced using feedstocks and resources indigenous to the Northeast. While the Northeast is also likely to import and use feedstocks and/or fuels from other regions under an LCFS, using locally sourced biomass for low carbon fuel production would provide economic benefits to the region, both by increasing employment and reducing expenditures on imported fossil fuels. NESCCAF's assessment was based on an evaluation of three categories of resources available in the region: (1) woody and agricultural biomass feedstocks; (2) waste-based biomass; and (3) electricity.

Recent scientific research has raised substantial concerns that the GHG lifecycle impacts of woody and agricultural biomass may result in increases of GHG emissions. Since a fuel standard could increase global demand for these types of feedstocks, concern is growing that the demand for biofuels is indirectly inducing changes in land use (e.g., clearing of forests for crop production) that increase net GHG emissions, even after considering the GHG benefits gained from displacing fossil fuels with biofuels. Research is ongoing to determine the lifecycle GHG impacts of biofuels production, but the issue of indirect land use change is not likely to be resolved soon. In consideration of this, NESCCAF's analysis focused on those regional biomass resources that are either waste products or are not currently being used to supply other markets.

Table ES-1 below shows the results of NESCCAF's evaluation of available woody, agricultural, and waste-based biomass resources in the Northeast by 2020. Maximum availability estimates for each category reflect total theoretical availability in the region. Estimates of likely availability are based on a conservative percentage of the maximum, reflecting considerations of resource cost and other important factors such as environmental sustainability and landowner preferences, which will limit actual resource availability.

Table ES-1. Northeast Biomass Resources, Maximum and Likely Annual Availability[5]

Type of Resource	Maximum Availability	Likely Availability
Woody biomass (dry tons)	33,463,889	5,021,667
Agricultural biomass (dry tons)	3,278,400	1,639,200
Municipal solid waste (dry tons)	66,492,294	20,390,809
Agr. & wastewater solids (dry tons)	11,880,541	5,940,271
Total Solid Biomass (dry tons)	**115,115,124**	**32,991,947**
Wastewater biogas (cubic ft.)	55,785,179	27,892,590
Waste oils (metric tons)	620,486	62,049

Geographically, the majority of the Northeast's available woody and agricultural biomass is located in New York and Pennsylvania. While the New England states also have significant quantities of woody biomass, much of this wood is being used to supply existing markets. Since it is generally not economic to transport biomass long distances (e.g., more than 50 miles), the geographic location of available biomass will likely influence the choice of locations for fuel processing and production plants. Based on these and other considerations, NESCCAF estimates a conservative total of about 33 million dry tons of waste-based, woody, and agricultural biomass is likely to be available for conversion into solid and liquid low carbon fuels. Additional resources for fuel production include waste oils and biogas.

However, as noted previously, actual biomass availability will vary depending on key factors such as market competition for resources, environmental concerns, landowner preferences, and public policies. For example, the RPS and RGGI programs have created an increase in demand for biomass resources—the RPS creates incentives for new biomass electricity plants, and RGGI encourages switching to or co-firing with biomass in existing coal plants.

Because electric vehicles (EVs) have very efficient drivetrains compared to internal combustion engines, electricity is also a promising low carbon fuel for transportation. This is especially true in the Northeast and Mid-Atlantic, where our electricity grid is already relatively "clean" and policies such as the RPS and RGGI are in place to further reduce the GHG intensity of electricity. At low levels of EV penetration into the marketplace (comparable to the numbers presented in Figure ES-1), the region is likely to have sufficient electricity generation to accommodate these vehicles if they are charged at times when extra generation capacity and in locations where sufficient transmission infrastructure exists.

Available biomass can be used directly (as a source of energy for heating or electricity generation) or converted into low carbon liquid biofuels for use in the transportation sector. Table ES-2 shows the results of an analysis which estimated the

[5] States included in this assessment are the six New England states, New York, New Jersey, and Pennsylvania. Figures represent estimated resource availability on an annual basis.

amounts of low carbon fuel that could be produced in 2010 and 2020 from the conversion of regionally available feedstocks into electricity, liquid fuels (biodiesel and cellulosic ethanol), and fuel for clean-burning heating units. Detailed assumptions for this analysis are presented in Chapter 5 and in Appendix D. It is important to note the numbers in Table ES-2 represent conservative estimates of feedstocks from within the region.

Table ES-2. Potential Low Carbon Fuel Production from Regional Resources

Type of Low Carbon Fuel	2010	Equivalent Gallons of gasoline or diesel (millions)	2020	Equivalent Gallons of gasoline or diesel (millions)
Electricity (MW)	849	200/600*	1,524	360/1,080*
Cellulosic ethanol (millions of gallons)	--	--	440	290
Thermal energy (no. of homes heated)	400,000	250	1,000,000	630
Neat biodiesel (millions of gallons)	6.6	6.1	6.7	6.2

*Gallons of equivalent gasoline/gallons of displaced gasoline assuming electricity is used to power electric vehicles (accounts for the efficiency of electric vehicles).

Column 1 in Table ES-2 shows different types of fuel that can be produced from conversion of the region's available feedstocks. Columns 2 and 4 show the amount of fuel, generating capacity, or homes heated in 2010 and 2020 respectively by converting a portion of the regionally available feedstocks to the fuel indicated in column 1. Columns 3 and 5 convert the energy contained in the fuel indicated in columns 2 and 4 to gallons of fuel – this is done merely to standardize the units in the table so that a comparison of the energy content of the different fuel types can be made. Unshaded rows indicate gasoline and shaded rows indicate transportation diesel or No. 2 fuel.

As can be seen from Table ES-2 based on current economics, available technologies, and other factors such as industry maturity, we expect in the early stages of a regional LCFS (in the 2011 timeframe), the majority of biomass resources could be used for electricity generation and thermal energy (i.e., heating). Production of cellulosic ethanol is not assumed in 2010 due to the fact that the technology is not yet commercialized. As markets continue to develop, we assume that more of the region's biomass resources would be deployed to support liquid low carbon fuel production. Actual conversion to fuels will depend on relative costs, technological capabilities, and public policies.

Importantly, the analysis shows that production of low carbon fuels from locally sourced feedstocks are potentially substantial. Table ES-4 shows that the use of feedstocks to generate electricity has the greatest potential to generate energy from regional resources, followed second by using feedstocks directly in thermal applications. If electricity generated from regionally available sources is assumed to power partial or all-electric vehicles, the amount of equivalent energy produced increases dramatically, as is demonstrated by the figures in columns 3 and 5.

Because NESCCAF did not conduct a formal resource sustainability assessment as part of this analysis, these estimates of low carbon fuel production are purposefully based on conservative estimates of likely resource availability. If sustainable levels of available resources are higher than these estimates, then potential fuel production could be accordingly higher.

Looking Ahead

Currently, 11 states in the region are in the process of developing a Memorandum of Understanding on a Northeast and Mid-Atlantic LCFS. These states include Connecticut, Delaware, Maine, Massachusetts, Maryland, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. By the end of 2009, the states intend to present a Memorandum of Understanding on an LCFS to the region's governors for consideration. There are currently six technical workgroups evaluating different aspects of the LCFS program and these workgroups are making recommendations on elements of the program. Looking ahead, the states in the region will need to reach consensus on specific program elements, develop the MOU, and promulgate regulations.

With regard to developments in technologies, implementation of the proposed federal RFS is expected to increase production of advanced biofuels. However, in light of the current uncertainty over the development of this production capacity, CARB has included a technology review in the LCFS proposed regulation. This review will allow for adjustment of carbon reduction requirements if volumes of advanced fuels are not sufficient to meet LCFS requirements.

Conclusions

Achieving a 10 percent carbon intensity reduction in the Northeast and Mid-Atlantic would result in annual emissions reductions on the order of those reduced by the California motor vehicle GHG standards and would exceed those realized from implementation of the RGGI program. In the early years of an LCFS, compliance could be achieved with moderate volumes of advanced biofuels. With full implementation of a 10 percent reduction in carbon intensity – such as California is proposing to require in 2020 – significant volumes of advanced biofuels and substantial numbers of advanced technology vehicles, or a mix of the two approaches would be required. These volumes of advanced fuel and numbers of advanced technology vehicles, while aggressive, are not infeasible: Several programs currently in place could facilitate compliance with the LCFS. Namely, the RFS, if implemented as proposed, will result in substantial production capacity for advanced biofuels. The RGGI and RPS programs will lower the carbon intensity of electricity in the Northeast. The Zero Emission Vehicle Program could result in the placement of 500,000 plug-in hybrids in the region. A number of conditions in the Northeast will also facilitate compliance. Electricity generated in the Northeast results in relatively low lifecycle GHG emissions on average, and there is sufficient extra electricity capacity to support large numbers of electric vehicles. The region also has substantial quantities of feedstocks that could be used to produce fuels for compliance with the LCFS or alternatively for compliance with the RPS and RGGI programs. In short, compliance with the LCFS – while feasible – will require substantial changes in the vehicle and fuel market. These changes will be a critical component of the overall strategy to reduce GHG emissions and mitigate the potentially severe consequences of global warming.

Report Organization

The remainder of this report is divided into five sections: Chapter 1 provides an overview and summarizes the current political and regulatory context. Chapter 2 provides an overview of what an LCFS is. Chapter 3 explores different potential compliance scenarios for an LCFS designed to achieve target reductions in average carbon intensity for Northeast transportation and heating fuels. Chapter 4 describes how the states might regulate the carbon content of fuels in the Northeast. Chapter 5 presents the results of an analysis of regional feedstocks and fuels such as woody and agricultural biomass, electricity, and municipal solid waste.

1. INTRODUCTION

The Northeast States Center for a Clean Air Future (NESCCAF) is a non-profit organization that promotes clean air through scientific research and policy development.[6] This report aims to help regulators and policy makers—including state-level air pollution control officials and state legislators—understand what a low carbon fuel standard (LCFS) is and what key issues are likely to arise in the implementation of an LCFS in the Northeast. In this report, the region is defined as either the Northeast (encompassing the eight NESCAUM states of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) or the northeastern and mid-Atlantic regions. The mid-Atlantic states, for the purposes of this report, include Delaware, Maryland, and Pennsylvania. Throughout the text, we refer either to the Northeast or northeastern and mid-Atlantic regions, depending on which states are included in the analysis described.

1.1. Background - The Importance of Transport Sector Emissions

Transportation emissions comprise approximately 40 percent of total GHG emissions. Figure 1-1 describes the contribution of different sources to total U.S. GHG emissions. Emissions associated with electricity generation have the largest volume, transportation-related emissions are second, followed by combustion of natural gas and other fuels in industrial processes (EPA 2008).

[6] NESCCAF has a sister organization called NESCAUM which stands for Northeast States for Coordinated Air Use Management. NESCAUM is an association of the air pollution control programs in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. The work conducted for this report was done by NESCCAF. The effort is also intended to support the NESCAUM and mid-Atlantic states' evaluation of a low carbon fuel standard for the region.

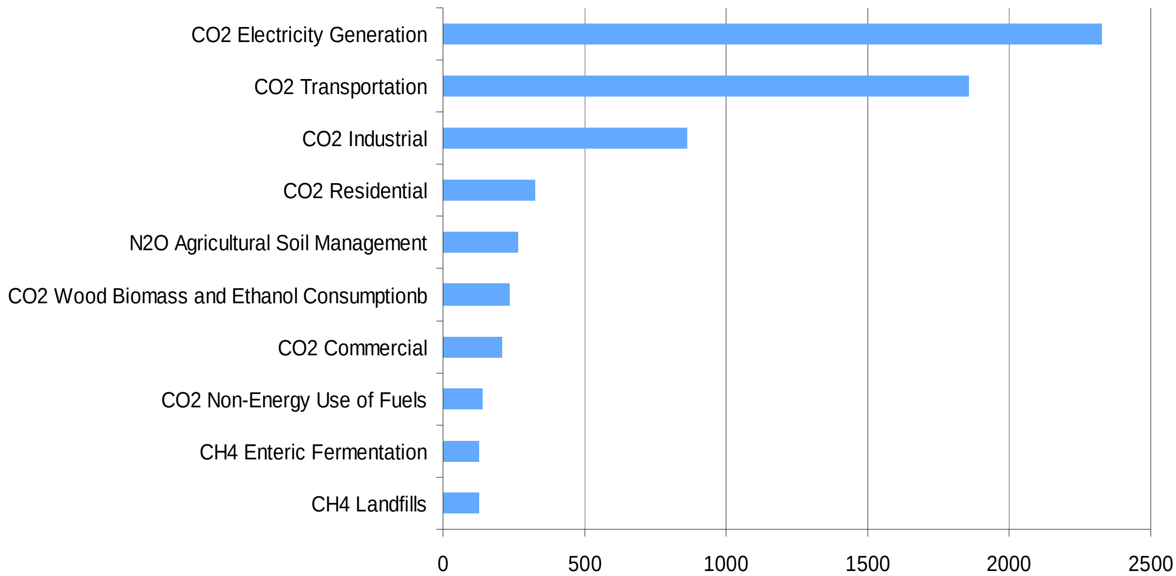


Figure 1-1. U.S. GHG Emissions by Sector, 2006

More than 80 percent of transportation sector emissions come from passenger cars, heavy trucks, and buses. Clearly, reducing GHG emissions from vehicles and transportation fuels is an essential component of any broad-based effort to address climate change. In addition, reducing transportation-related GHG emissions is important from the standpoint of reducing the nation's dependence on petroleum.

There are three main policy approaches to reducing transportation-related GHG emissions. The first approach is to reduce GHG emissions from vehicle tailpipes. A second approach is to reduce demand for fuel by reducing (or slowing growth in) the number of miles people travel in cars each year (known as "vehicle miles traveled"). The other significant option is to change the properties of the transportation fuel itself—that is, to reduce the amount of GHGs emitted when a given quantity of fuel energy is used. An LCFS targets this last component of transportation sector emissions (i.e., greenhouse gas emissions from fuels themselves).

With the adoption of California's Low Emission Vehicle (LEV) GHG standards, the northeastern states have already put in place an important cornerstone of the region's strategy for reducing transportation-related GHG emissions. The LCFS represents a potentially important complement to this vehicle-based initiative. To evaluate its potential contribution to an effective regional strategy for reducing transport sector emissions, state environmental officials need balanced, policy-relevant research and analysis. This study provides a technical basis to assess the merits and challenges of a regional LCFS, and an initial evaluation of issues and factors that are specific to the Northeast's consideration of a regional LCFS.

For example, the Northeast uses large volumes of fuel for space heating, and given that heating fuel is similar to transportation fuel, inclusion of heating fuel in the scope of a regional LCFS in the Northeast presents significant GHG mitigation opportunities.[7] The possibility of incorporating heating oil into the Northeast's LCFS is discussed in Chapters 3, 4, and 5.

This study has several principal objectives:

- Evaluates opportunities and challenges related to the implementation of an LCFS for the region;
- Provides key insights for designing and implementing an LCFS for the Northeast; and
- Promotes and facilitates the adoption of a regionally consistent state program.

Additionally, this study builds on and adds to the substantial research being conducted on low carbon fuel options and related policies by the California Air Resources Board (CARB), the University of California (UC Davis and UC Berkeley), the U.S. Environmental Protection Agency (EPA), the Canadian Provinces, and the European Commission (CARB 2009; Wang 2005; EPA 2009; Canadian Parliament 2008; European Commission 2008).

A number of important issues related to low carbon fuels are not addressed in this report. Among them, serious concerns over the GHG emissions associated with land-use changes prompted by expanded biofuels production have not been researched as part of this analysis. NESCCAF relied on existing inputs to emissions modeling tools for the analysis but did not conduct new research into these issues. Further, NESCCAF did not conduct original research on potential impacts to water and air quality or biodiversity from the increased use of biomass, mid-level ethanol blends, biodiesel, or other potential environmental impacts directly or indirectly linked to the region's potential implementation of an LCFS.

To garner expert advice in this effort, NESCCAF formed a Project Advisory Committee made up of representatives from the regulatory community, industry, academia, and environmental organizations. The Committee has provided valuable input and guidance at key junctures in NESCCAF's research effort.

1.2. Report Organization

The remainder of this report is divided into six sections: Chapter 2 summarizes the current political and regulatory context and describes how an LCFS might be structured. Chapter 3 explores different potential compliance scenarios for an LCFS designed to achieve target reductions in average carbon intensity for transportation and heating fuels in the Northeast. Chapter 4 describes possible approaches to regulating the GHG content of fuels in the Northeast. Chapter 5 presents the results of an analysis of

[7] Throughout this report, "heating oil" refers to distillate fuel oil used for heating purposes. This generally refers to No. 2 distillate oil and a very small percentage of No. 6 fuel oil, which is used on a much more limited basis than No. 2. For a more detailed description of the use of heating oil in the Northeast, refer to Appendix C.

local feedstocks such as woody and agricultural biomass, electricity, and municipal solid waste and their potential production into low carbon fuels.

2. WHAT IS A LOW CARBON FUEL STANDARD?

A Low Carbon Fuel Standard (LCFS) is a performance-based standard designed to reduce the GHG-intensity associated with the production, transport, and combustion of transportation fuels. The only LCFS regulation in the world, adopted by the California Air Resources Board and described in more detail below, defines transportation fuels as those fuels used in passenger cars, trucks, and nonroad vehicles such as construction equipment and boats.[8] An LCFS regulation requires a percentage reduction in the intensity of GHGs emitted from the production and use of transportation fuels, relative to a baseline fuel. Because it is a performance-based standard, the LCFS is similar to other fuels regulations that are currently in place, such as the reformulated gasoline program – which requires a percent reduction in the amount of vehicle smog-forming pollution emitted relative to conventional gasoline. What distinguishes a low carbon fuel standard apart from other regulations is the requirement that regulated entities conduct a full lifecycle accounting of GHG emissions for fuels regulated under the program.

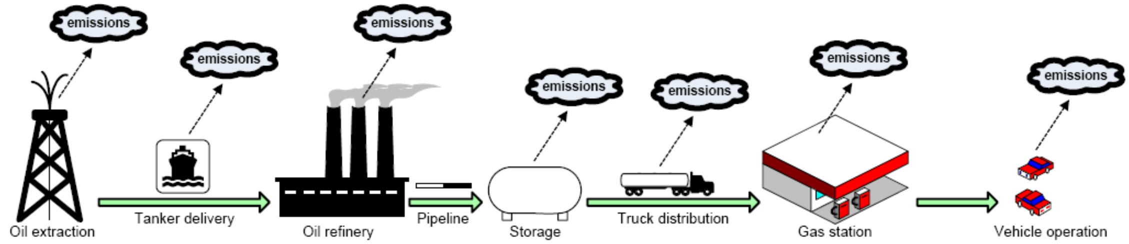
In April of 2009, CARB adopted an LCFS that will reduce the intensity of lifecycle GHG emissions associated with transportation fuels 10 percent by 2020. The program, when fully implemented, is expected to result in substantial GHG reductions from the transportation sector. The State of California adopted the LCFS as an essential component of a broader, integrated strategy for reducing GHG emissions under the state's *Global Warming Solutions Act of 2006* (A.B. 32). The overall goal of A.B. 32 is to reduce California's GHG emissions to1990 levels by 2020. To implement this requirement, environmental regulators at CARB are developing a Climate Change Scoping Plan that "proposes a comprehensive set of actions designed to reduce overall carbon emissions in California" (CARB 2008). The Scoping Plan references California's LCFS as one of these actions, within a set of programs targeting the transportation sector. California's actions and other recent initiatives aimed at reducing fuel-related GHG emissions are discussed further in later sections of this report.

The basic elements of the LCFS as required by CARB are described in the following section.

2.1. Lifecycle assessment and calculation of average fuel carbon intensity

As mentioned above, a critical component of the LCFS is full lifecycle carbon accounting. Accounting for lifecycle emissions means the standard includes all GHG emissions associated with the production, storage, transport, delivery, and combustion of a given fuel. As an example, Figure 2-1 provides a graphic depiction of the GHG emissions that need to be accounted for as part of a lifecycle analysis for petroleum.

[8] Fuels used in oceangoing vessels or aircraft are regulated internationally, and thus are not included in the scope of California's LCFS.



Source: Wang and Delucchi 2005.

Figure 2-1. Emissions included in full lifecycle GHG accounting for petroleum

As can be seen in Figure 2-1, both "upstream" and "downstream" emissions are included in the lifecycle assessment. Thus, emissions associated with extraction of crude oil; transport of the oil to a refinery; refinery-related emissions; emissions associated with transporting the finished fuel to a wholesale distribution facility; distribution to retail outlets; and finally emissions associated with fuel combustion in vehicles are included in the baseline and in the calculation of fuel emissions.[9]

The GHG intensity of different fuels is typically expressed as full lifecycle emissions per unit of energy content. The LCFS requires a percent reduction in the carbon intensity of fuel, measured in CO_2-equivalent emissions per megajoule (MJ) of energy (CO_2e/MJ), relative to the baseline fuel. It is important to note that an LCFS, like other fuel regulations, does not cap total fuel-related emissions—actual emissions will depend on the total amount of fuel consumed, which in turn depends on vehicle efficiency and miles traveled. Rather, the LCFS limits the amount of emissions generated per unit of fuel energy used.

Figure 2-2 below illustrates the calculation of average fuel carbon intensity (AFCI) for a mixture of fuels with different lifecycle characteristics and sales volumes. This calculation is central to implementing an LCFS. Once a weighted average AFCI is calculated for all fuels sold in a given year, this result can be compared to a baseline AFCI to determine whether overall targets for reductions in the intensity of fuel GHG emissions have been met.

[9] This figure provides an illustration only. The specific emissions sources that must be taken into account as part of a similar analysis for other fuels will differ.

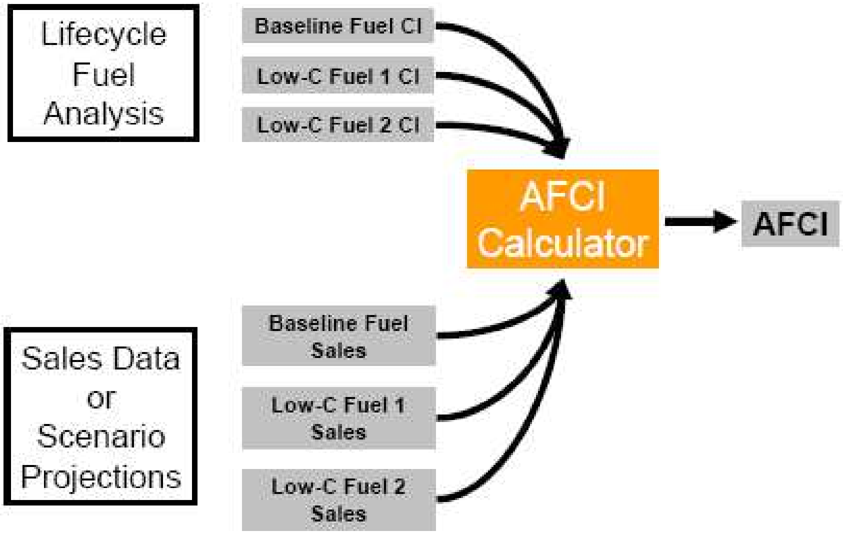


Figure 2-2. Calculating Average Fuel Carbon Intensity (AFCI)

The California LCFS requires a gradual reduction in the GHG intensity of gasoline and diesel between 2011 and 2020. The phase-in of the standards is shown in Table 2-1.

Table 2-1. CARB LCFS Compliance Schedule

Year	Carbon Intensity for Gasoline and Fuels Substituting for Gasoline (g/MJ)	Gasoline and Fuels Substituting for Gasoline % Reduction	Carbon Intensity for Diesel and Fuels Substituting for Diesel (g/MJ)	Diesel and Fuels Substituting for Diesel % Reduction
2010	Reporting Only			
2011	95.61	0.25%	94.47	0.25%
2012	95.37	0.5%	94.24	0.5%
2013	94.89	1.0%	93.76	1.0%
2014	94.41	1.5%	93.29	1.5%
2015	93.45	2.5%	92.34	2.5%
2016	92.50	3.5%	91.40	3.5%
2017	91.06	5.0%	89.97	5.0%
2018	89.62	6.5%	88.55	6.5%
2019	88.18	8.0%	87.13	8.0%
2020 and subsequent years	86.27	10.0%	85.24	10.0%

Source: CARB 2009; Proposed Regulation to Implement the Low Carbon Fuel Standard.

2.2. Political and Regulatory Context for Adoption of the LCFS

This section provides background information on how the LCFS forms a part of an integrated strategy to reduce man-made GHG emissions.

2.2.1. International Context

As early as 1992, international awareness of the many potential risks associated with global warming led 160 countries, including the United States, to adopt a Framework Convention on Climate Change with the stated objective of achieving "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (UN 1992).

Toward this objective, signatories pledged to work to stabilize greenhouse gas emissions. A number of industrialized countries, again including the United States, adopted the specific near-term goal of returning GHG emissions in 2000 to 1990 levels. It subsequently became evident that most countries, including the United States, were not on track to meet this objective. In response, parties to the Framework Convention adopted the Kyoto Protocol in 1997, which included targets and timetables for reducing GHG emissions to specific levels for each country. As of early 2003, 102 countries had ratified or acceded to the Protocol. However, the United States—citing economic concerns—has not ratified the Kyoto Protocol.

Notwithstanding the federal government's reluctance in the 1990s to impose mandatory limits on GHG emissions, many state and local leaders had become sufficiently concerned about the issue of climate change by the end of the 1990s to adopt a range of measures aimed at reducing GHG emissions within their jurisdictions. This trend began with a few leading states in the early 1990s, but has accelerated recently. Between 2001 and 2008, over 30 states passed new legislation or executive orders specifically aimed at addressing climate change (Pew 2009).[10] These policies include comprehensive state action plans with quantitative GHG reduction targets, mandatory GHG reporting requirements, and regulations limiting emissions from a specific sector such as electric power generation or transportation.

2.2.2. Federal Efforts to Reduce Petroleum Consumption

Renewable Fuel Standard (RFS)

The federal Renewable Fuel Standard (RFS), first adopted in the Energy Policy Act of 2005 and subsequently amended in the Energy Independence and Security Act of 2007 (EISA), attempts to respond to energy security and environmental concerns by mandating a steady increase in the volume of renewable fuel included the U.S. transportation fuel supply over the next decade and a half. The mandate was significantly expanded under EISA, which requires 36 billion gallons of renewable fuels by 2022. In May 2009, EPA issued a proposed rule for the RFS. As part of that rule, EPA is required to establish two general categories of renewable fuel: conventional biofuels (i.e., ethanol derived from corn starch) and advanced biofuels. Under the new rule, the federal RFS

[10] Additionally, other states adopted measures that were not expressly aimed at climate change but clearly were driven at least in part by the issue of global warming.

will account for direct emissions of GHGs and significant indirect emissions, such as emissions from land use changes. All stages of fuel and feedstock production and distribution are to be included. Specific RFS program requirements under current law are summarized in Table 2-2.

Table 2-2. Requirements of Energy Independence & Security Act (EISA) of 2007

EISA Requirements	**Conventional Biofuels**[11]		**Advanced Biofuels**[12]		
	Corn Ethanol (existing facilities)[13]	Corn Ethanol (new or expanded facilities)	Cellulosic Biofuel	Other Advanced Biofuels	Biomass Based Diesel
Volume (10^9 Gal)	± 13.4	± 1.6	= 16.0	= 4.0	= 1.0
Volumes Expected/ Required for Corn Ethanol and Advanced Biofuels (10^9 Gal)	= 15.0		= 21.0		
Total Volume	36 billion gallons annually				
Year	2015		2022	2022	2012
GHG Baseline Reduction	None	20%	60%	50%	50%

Sources: EISA 2007, Renewable Fuels Association 2008.

An analysis conducted by the Renewable Fuels Association (RFA) estimates that the RFS will allow as much as 13.4 billion gallons of corn ethanol per year to be incorporated into transportation fuels without any associated GHG reduction requirement (RFA 2008). The remaining 1.6 billion gallons of corn ethanol subject to the mandate must achieve at least a 20 percent reduction in lifecycle GHG emissions compared to conventional gasoline. Use of an additional 21 billion gallons of "advanced biofuels" will be required by 2022. The RFS defines the term "advanced biofuels" to include:

[11] The estimates in Table 2-2 of corn ethanol gallons were provided by the Renewable Fuels Association.
[12] The number of gallons of advanced biofuels listed in Table 2-2 is specified in the EISA legislation.
[13] For corn ethanol produced in plants constructed prior to the effective date of EISA, no reduction in lifecycle GHG emissions are required. For corn ethanol produced in plants where construction commenced after the effective date of EISA (or in plants that are expanded after the effective date of EISA) a 20 percent reduction requirement in lifecycle GHG emissions is required.

- Cellulosic biofuel derived from plant cellulose, hemicellulose, or lignin;[14]
- Ethanol derived from sugar or starch other than corn starch;
- Ethanol derived from specified waste materials (e.g., crop residues, vegetative waste, animal waste, food waste, yard waste);
- Biomass-based diesel;
- Biogas (e.g., landfill gas, sewage waste treatment gas) derived from renewable biomass;
- Butanol or other alcohols derived from renewable biomass; and
- Other fuel derived from cellulosic biomass.

Regulated parties under the RFS are required to demonstrate compliance through a tracking system, whereby they accumulate renewable identification numbers (RIN) associated with the batches of renewable fuel that they purchase and blend with petroleum-based fuels. It is anticipated that EPA will require information in the RIN to indicate the specific category or type of biofuel being blended. For example, if a biofuel falls into the 60 percent GHG reduction category, the RIN will indicate this.

Importantly, the RFS does not impose any constraints on the carbon intensity of the non-renewable portion of the transportation fuel mix, which will continue to account for as much as 80 percent of all fuel use by the transport sector.[15] NESCCAF estimates that under a best case scenario, the RFS will reduce transportation fuel-related GHG emissions in the Northeast by 2.7 percent in 2020.[16] Thus, the federal RFS could complement efforts in the Northeast to achieve GHG emission reductions through an LCFS.

2.2.3. Federal Fuel Economy Standards

In January 2009, the Administration approved a U.S. Department of Transportation proposal to increase the fuel economy of cars produced after 2011. In May 2009, the National Highway Traffic Safety Administration and EPA jointly announced a rulemaking to increase the fuel economy of passenger cars to 35 miles per gallon in 2016 and to regulate motor vehicle GHG emissions. The standards will result in passenger car GHG emissions nationwide in 2016 that are equivalent in stringency to the California motor vehicle GHG standards.

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[14] According to the definition of "cellulosic biofuel," the raw materials must be derived from "renewable biomass," which includes planted crops and crop residue produced on pre-existing agricultural land (i.e., land that was already cleared prior to the effective date of the law); planted trees and tree residue from tree plantations on non-federal, previously cleared land; animal waste material and animal byproducts; slash and pre-commercial thinnings from non-federal forestlands; biomass cleared from lands for the sole purpose of protecting people, buildings, and public infrastructure from risk of wildfire; algae; and separated yard waste or food waste.

[15] Thus, increases in use of high carbon fuels, such as fuels derived from tar sands, to make diesel and gasoline will not be addressed by the RFS.

[16] This assumes that advanced biofuels are distributed evenly throughout the U.S. Additional information on this estimation can be found in Chapter IV, Scenario Analysis.

2.2.4. California's Low Carbon Fuel Standard

In April 2009, the California Air Resources Board approved the low carbon fuel standard. CARB staff are now in the process of addressing comments on the regulation and California anticipates finalizing the regulation by the end of 2009. The LCFS requires regulated entities to reduce the carbon intensity of California's transportation fuels by at least 10 percent in 2020.

California's LCFS covers all gasoline and diesel fuel used by transportation sources, with the exception of fuels used in aviation and by ocean-going vessels. CARB staff have released an *Initial Statement of Reasons* supporting the program adoption.

Many of the entities regulated under the federal RFS program will also be regulated under the California LCFS. In addition, the RFS GHG reduction requirements will further the achievement of the LCFS goals.

2.2.5. The California Global Warming Solutions Act

California's A.B. 32 legislation calls for a program of regulatory and market mechanisms to achieve quantifiable and cost-effective reductions of GHGs. Specifically, under A.B. 32, CARB is required to:

- Establish a statewide GHG emissions cap for 2020, based on 1990 emissions;
- Adopt mandatory reporting rules for significant sources of GHGs;
- Develop a plan for achieving emission reductions from significant GHG sources via regulations, market mechanisms, and other actions;
- Adopt regulations by January 1, 2011 that achieve maximum technologically feasible and cost-effective reductions in GHGs, including provisions for using both market mechanisms and alternative compliance mechanisms;
- Evaluate various factors relevant to the implementation of a program to reduce the state's GHG emissions, including impacts on California's economy, the environment, and public health; equity between regulated entities; electricity reliability; and conformance with other environmental laws.

CARB's Scoping Plan further develops three interrelated program components to address the major factors that determine emissions in the transportation sector: (1) vehicle technology, (2) fuels, and (3) vehicle use. The LCFS is the vital "second leg" in this three-part transportation related strategy.

2.2.6. European and Canadian LCFS Programs

Other countries are adopting low carbon fuels programs similar to California's; like California they are also grappling with concerns about the sustainability and indirect impacts of these policies—concerns that are increasingly being voiced by environmental organizations and governments in other nations. Specific LCFS-related initiatives in other countries include:

- **European Union:** The European Commission has revised its Fuel Quality Directive to include a required reduction in the lifecycle GHGs associated with fuels. The goal of this revision is to reduce the average GHG intensity of transportation fuels used in Europe 10 percent below 2010 levels by 2020 (EurActive 2008).
- **United Kingdom**: The UK has established a Renewable Transport Fuel Obligation (RFTO), similar to the U.S. RFS, that requires 5 percent by volume of all road transportation fuel to be renewable by 2010 (U.K. Department for Transport).
- **British Columbia:** The province has adopted an LCFS that aims to achieve a 10 percent reduction in the carbon intensity of passenger vehicles by 2020.

Additional countries are actively examining the sustainability and GHG impacts of biofuels:

- **Netherlands:** The "Cramer Commission" report published in June 2006 established sustainability principles and suggested criteria for biofuels (Archer 2007).
- **Germany:** Germany's federal environment agency *Umweltbundesamt* (UBA) is investigating the development of a sustainability certification for biofuels in conjunction with the Institute for Energy and Environmental Research (IFEU) and the International Council on Clean Transportation (ICCT) (UBA 2008).

2.2.7. Northeast State Climate Initiatives

The northeastern states have led the nation in establishing initiatives and programs to address climate change. In 2001, the Conference of New England Governors and Eastern Canadian Premiers (NEG/ECP) adopted a regional Climate Change Action Plan (NEG/ECP 2001). The plan establishes an initial target for stabilizing aggregate GHG emissions in New England, Quebec, New Brunswick, Nova Scotia, Newfoundland, and Prince Edward Island at 1990 levels by 2010. By 2020, the NEG/ECP plan calls for reducing emissions 10 percent below 1990 levels, with substantial further reductions (or as much as 75 percent–80 percent) to be achieved in subsequent years. In response to the expected increase in regional emissions attributable to the transportation sector, the regional plan and state specific plans target mechanisms for reductions in vehicle miles traveled (VMT) and fuel economy.

In recent years, other northeastern states have developed state-specific plans and/or GHG reduction targets, and New England states have formalized the NEG/ECP targets by signing them into law or establishing more stringent targets. These state-level initiatives are summarized in Table 2-3 below.

Table 2-3. Summary of Northeast State Climate Legislation and Actions

State	Legislation or Plan	Year Enacted	Emission Reduction Targets		
			2010	2020	2050
CT	Act Concerning CT Global Warming Solutions	2008		10% below 1990 levels	80% below 1990 levels
ME	Act to Provide Leadership in Addressing the Threat of Climate Change	2003	1990 levels	10% below 1990 levels	75-80% below 1990 levels
MA	Global Warming Solutions Act	2008		10-20% below 1990 levels	80% below 1990 levels
NH	NEG/ECP Climate Change Action Plan Targets				
NJ	Global Warming Response Act	2008		1990 levels	80% below 2006 levels
NY	State Energy Plan and Final Impact Statement	2002	5% below 1990 levels	10% below 1990 levels	
PA	Climate Change Roadmap	2007		25% below 2000 emissions by 2025	80% below 2007 emission levels by 2050
RI	Global Warming Solutions Act	Pending		20% below 1990 levels	80% below 1990 levels
VT	NEG/ECP Climate Change Action Plan Targets				

Sources: Various state climate change action plans.

It is worth noting that the Massachusetts *2008 Global Warming Solutions Act* includes requirements for biofuels. Specifically, this legislation mandates the use of 2 percent biodiesel in transportation fuels by 2010 and 5 percent by 2015; it also provides tax incentives for the production of cellulosic ethanol. Additional actions to reach Massachusetts' aggressive emissions reduction goals will be outlined in an implementing plan that the state expects to release in 2009.

The above described efforts at the federal and state levels to restrict passenger car and light truck tailpipe emissions will result in substantial reductions in transportation GHG emissions. These efforts, when combined with an LCFS to reduce the carbon intensity of transportation fuels, and initiatives to reduce miles driven each year will bring the states and the federal government closer to the goal of reducing the impacts of climate change. The LCFS is a critical component of this overall strategy.

3. LOW CARBON FUEL VOLUME REQUIREMENTS

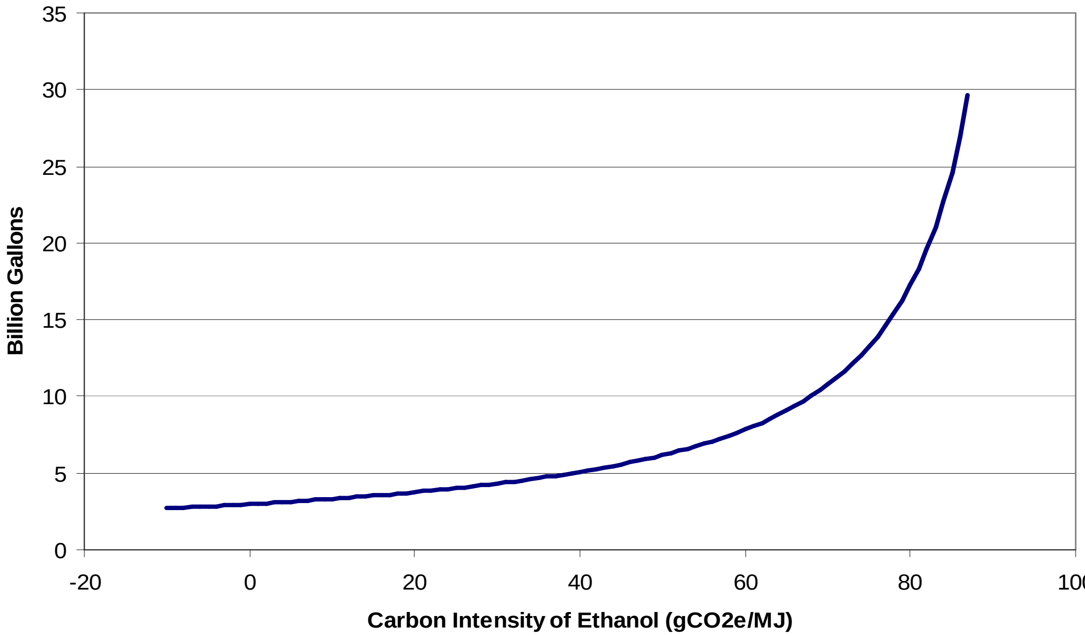
This chapter presents results from a NESCCAF analysis of strategies that could be used to achieve a 10 percent reduction in the average carbon intensity of transportation fuels in the eight NESCAUM states.[17] NESCCAF considered several combinations of low carbon fuels and calculated the volumes that might be required in order to meet a 10 percent LCFS by 2020. The results provide insights into the challenges and opportunities that might result from the implementation of a 10 percent reduction in Average Fuel Carbon Intensity (AFCI) in the Northeast.[18] An understanding of the volumes of different types of fuels that might be required to comply with an LCFS can inform key programmatic decisions and help identify potential obstacles to the successful implementation of a low carbon fuels program.

Importantly, NESCCAF did not attempt to assess the technical feasibility or market readiness of potential fuel types or LCFS compliance scenarios. Therefore, the scenarios presented in this report should not be interpreted as recommendations or even plausible projections; rather, they are illustrative of the volumes of different types of fuels that would be needed to comply with a specific carbon intensity (CI) reduction target under an LCFS. Indeed, in some cases, the scenarios depict volumes of advanced fuels or vehicles that may greatly exceed likely prospects for commercialization.

It is also important to note that regulated entities might choose from an unlimited number of possible combinations of fuel pathways to comply with an LCFS. Furthermore, the composition of the baseline fuels mix, mechanisms for reducing AFCI, and specification of certain carbon intensity values will depend on a number of key program decisions that may differ from the assumptions in this analysis. For these reasons, it would be difficult to assign a meaningful probability to a particular compliance scenario. Instead, NESCCAF has chosen to illustrate the scope of the compliance challenge through simple boundary analyses, and to present several example scenarios that illustrate points of particular interest – namely, the quantities of certain substitute fuels that could be required to meet a 10 percent reduction target.

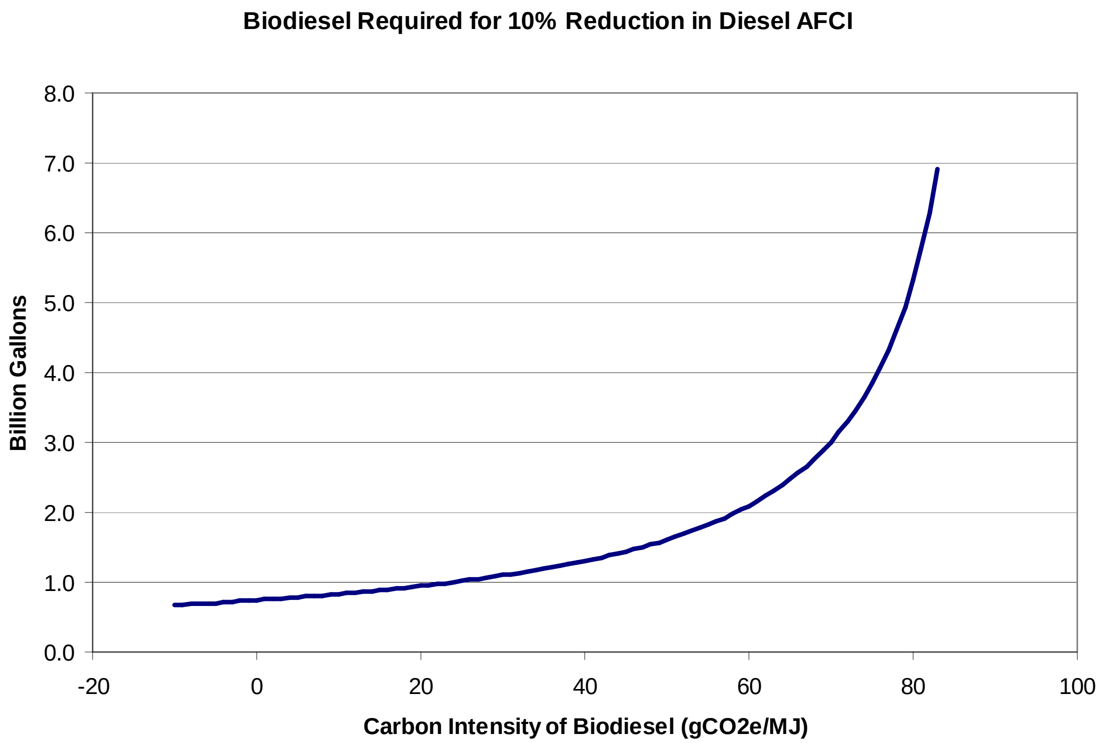
As discussed earlier, the impact of a particular fuel pathway on AFCI depends on both its CI and its sales volume. For example, if fuels are available that achieve very low carbon intensity levels, a regulated entity would need to supply a relatively small volume to reduce their average CI. Alternatively, a regulated entity could choose to comply using a larger volume of less advanced fuel. Using a simple case to illustrate the interaction of CI and volume, Figure 3-1 shows the volume of ethanol that would be required to reduce gasoline AFCI by 10 percent across a range of ethanol CI values. Figure 3-2 shows a similar effect for biodiesel on the diesel AFCI. Note that these are idealized examples. In practice, regulated entities would likely supply a combination of lower-CI and higher-CI fuels.

[17] The eight NESCAUM states are Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.
[18] Average Fuel Carbon Intensity (AFCI) is the metric used to determine compliance with a Low Carbon Fuel Standard. A detailed explanation of the AFCI metric can be found in Chapter 2.



Note: Assumes baseline of 20 Bgal gasoline at 96.7 gCO_2e/MJ.

Figure 3-1: Ethanol Volume Required for 10 Percent Reduction in 2020 Gasoline AFCI, NESCAUM region



Note: Assumes baseline 6.9 Bgal diesel fuel at 93 gCO_2e/MJ.

Figure 3-2: Biodiesel Volume Required for 10 Percent Reduction in 2020 Diesel AFCI, NESCAUM region

3.1. Assumptions and Limitations of Analysis

A critical question for policy makers concerns the plausibility of the assumptions that underlie the compliance scenarios discussed in this chapter. As previously discussed, the purpose of these scenarios is not to suggest that they are likely to be realized in the 2020 timeframe, but rather to illustrate the scale of the challenge that would accompany a 10 percent AFCI reduction for both baselines in the Northeast. Due to the pre-commercial status of the technologies that have been evaluated as potential low carbon substitutes, the likelihood of achieving substantial CI reductions from either baseline by 2020 remains highly speculative.

We also note that the scenarios presented here exclude potential technologies for heavy-duty vehicles that are currently under development, such as medium-duty plug-in hybrid trucks. A number of these vehicles are currently operating in pilot programs, and commercial-scale deployment may be possible in future years. Their usefulness in complying with an LCFS depends on many of the same unknowns regarding grid mix, vehicle specifications, and user behavior that apply to light-duty EVs and PHEVs, as discussed in section 3.4.

3.1.1. Electric-Drive Vehicles

Our gasoline scenarios assume 3 to 6 million EVs and PHEVs in use in the NESCAUM states by 2020, representing 9 to 17 percent of the total light-duty vehicle fleet. Achieving these fleet penetration levels could require annual sales on the order of 12 to 36 percent of the total market by 2020. Given that no grid-connected electric-drive vehicles are currently available for sale in significant numbers, these market penetration rates are very optimistic. For comparison, Toyota's first mainstream hybrid (the Prius) first went on sale in 1997; Toyota now offers six models of hybrids that together comprise 12 percent of Toyota's annual sales. Our scenarios assume penetration rates for both EVs and PHEVs that match or far exceed Toyota's hybrid sales trajectory for the entire fleet (all manufacturers) by 2020.

While these sales numbers are unlikely, they are not inconceivable. Many automakers have announced ambitious product plans for advanced vehicles that, if aggressively implemented, could signal an unprecedented shift in the makeup of the U.S. light-duty fleet. As examples, GM has announced plans to offer the Volt (a PHEV with a 40-mile all-electric range) for sale in 2010. Toyota has announced plans to deploy 300 PHEVs worldwide in 2010. Chrysler is considering at least two EV models for release in 2010. Mitsubishi plans to introduce an electric vehicle with a range of 100 miles in 2010. Nissan has announced a pure electric car for fleets in 2010 and for sale to retail consumers in 2012. Numerous variables will affect actual EV and PHEV sales, including: gasoline prices, tax credits, availability of models, vehicle performance, federal and state incentives or mandates, the availability of "smart" charging infrastructure, among other factors.

If these optimistic sales volumes were to be realized in the Northeast's fleet, they would represent a substantial increase in electricity demand, on the order of 14,000 GWh for the less aggressive scenarios and 22,000 GWh for the more aggressive scenario. This represents 4 percent and 7 percent, respectively, of total electricity consumption in the NESCAUM region in 2005. If these vehicles were charged exclusively when extra electricity capacity exists, such as nighttime, the additional demand could likely be met without the need for new generating capacity in the region. However, because some of this demand would be served by coal plants, charging when extra capacity exists may not provide the lowest possible carbon intensity value for transportation electricity. The assumptions used in this analysis to characterize the role of electricity as a low carbon transportation fuel are discussed in Section 3.3 of this chapter and in more detail in Chapter 5 and Appendix A.

3.1.2. Biofuels

Our scenarios assume 0.9 to 1.5 billion gallons of advanced ethanol (with carbon intensities of 0 to 48 g/MJ) and 710 to 840 million gallons of advanced biodiesel in 2020 (with carbon intensities of 20 to 47 g/MJ). These volumes are in addition to the 1.75 billion gallons of new and advanced ethanol and 240 million gallons of advanced biodiesel that NESCCAF estimates could be sold in the region due to mandates in the federal Renewable Fuels Standard (RFS2). For comparison, according to industry estimates 460 million gallons of biodiesel and 7.8 billion gallons of corn ethanol were produced in the U.S. in 2007 (National Biodiesel Board 2009; Renewable Fuels

Association 2009). No advanced, low carbon ethanol or biodiesel is currently being produced in large quantities - although a number of promising technologies are under development, such as: production of biodiesel from algae, production of paraffins from wood, conversion of cellulosic feedstocks for ethanol production, and other innovative approaches. Considering the pre-commercial status of these advanced biofuel technologies, the volumes envisioned in the compliance scenarios (and perhaps even the volumes called for under RFS2) are highly optimistic. However, it is plausible that some of the advanced biofuels which are currently under development will be available in significant quantities by 2020.

3.1.3. Other Key Assumptions

In all scenarios presented in this report, we assume an energy economy ratio[19] (EER) of 4.0 for EVs and 2.4 for PHEVs, and we assume that the federal RFS will result in 1.3 billion gallons of cellulosic ethanol (defined as achieving a 60 percent carbon intensity reduction from the gasoline baseline), 300 million gallons of “advanced” ethanol (defined as achieving a 50 percent lower carbon intensity than gasoline), and 200 million gallons of “new” corn ethanol (20 percent lower carbon intensity than gasoline) delivered in the Northeast by 2020.

Numerous additional assumptions bear directly on the design and outcomes of most scenario projections. When evaluating sensitivity to multiple variables, the number of potential scenarios can quickly become impractical to simulate and to interpret. For the purpose of the scenario discussions presented in this chapter, we chose to “lock in” certain assumptions in order to facilitate comparison among scenarios. This should not be taken as a recommendation of a specific policy option. The benefits and drawbacks to each approach are explored in detail in Chapter 4.

[19] The energy economy ratio (EER) is a measure of the energy efficiency of an electric drive vehicle relative to a baseline conventional vehicle. It is defined as the distance an EV will travel divided by the distance a reference vehicle will travel for a given amount of energy. For example, an EV with EER of 4 will travel four times farther than a conventional vehicle using the same amount of energy. A more detailed description of EER is found in Section 3.5.1 of this chapter.

Table 3-1. Summary of Key Assumptions Common to All Scenarios

Decision Item	Default Assumption
Gasoline baseline fuel mix	100% RBOB
Diesel baseline fuel mix	100% ULSD
Distillate oil sulfur content	15 ppm
RFS Cellulosic Ethanol	1.3 billion gallons
RFS “Advanced” Ethanol	300 million gallons
RFS “New” Corn Ethanol	190 million gallons
RFS Biodiesel	240 million gallons
Count RFS fuels toward AFCI reduction?	Yes
Include light-duty diesel in diesel baseline?	Yes
Include nonroad engines in diesel baseline?	Yes
Scenario region for transportation demand	8-State NESCAUM Region
Electric vehicle (EV) Energy Economy Ratio (EER)	4.1
Plug-in hybrid-electric vehicle (PHEV) EER	2.4

3.2. Scenario Descriptions

This section describes three gasoline and two diesel compliance scenarios. Two important points bear repeating here. First, note that where advanced biofuels are envisioned, these fuels could in theory be derived from a variety of different feedstocks, such as woody biomass or municipal solid waste, using different production processes. Any number of combinations of advanced fuels could give an average carbon intensity value equivalent to those illustrated here for a particular biofuel. Secondly, as noted previously, NESCCAF did not study the technical feasibility or market readiness of advanced or emerging biofuel technologies. Rather, our scenario analysis is intended only to illustrate the quantities of various types of fuels that would be required to meet a 10 percent AFCI reduction target.

3.2.1. Baseline

Regulators may choose to define the baseline fuels mix in one of several ways. In order to simplify the discussion and interpretation of the scenarios in this report, and to avoid pre-supposing the outcomes of ongoing policy discussions, NESCCAF opted to assume idealized baseline fuel mixes for both gasoline and diesel. The region’s gasoline has contained increasing percentages of ethanol (almost exclusively produced from corn feedstocks using conventional methods) since the phase-out of M*t*BE in the middle of this decade. Depending on regulators’ approach to selecting a baseline year and defining the composition of the baseline fuel mix, the “gasoline” baseline may in fact include up to 10 percent ethanol by volume. Therefore, depending on the CI value assigned to this ethanol, the gasoline baseline CI could vary with each year. For the purpose of this analysis, NESCCAF assigned baseline ethanol a CI value of 96.7 gCO_2e/MJ, which is equivalent to that of gasoline blendstock (RBOB). A consequence of this assumption is that the precise volume of ethanol in the baseline does not affect the baseline carbon intensity.

For diesel fuel, the Northeast's fuels mix has changed with each recent year as sulfur limits have been phased in, first for highway diesel, then for nonroad diesel, and potentially in the future for fuel oil used for heating. This is significant because low-sulfur diesel has a higher carbon intensity than does conventional diesel fuel. This is mainly due to the energy consumed in the de-sulfurization process. Thus, as with gasoline, the precise year and composition for the baseline fuel will affect the baseline carbon intensity from which reductions are sought. Again, as with the gasoline baseline, NESCCAF opted to model an idealized baseline diesel fuel that meets the ultra-low-sulfur diesel (ULSD) standard currently in place for highway diesel, and to assume that this fuel would be used for all distillate markets in the baseline and scenario years. While this will result in a lower CI value, it will simplify the interpretation of the scenarios; in addition, it may be an advisable policy approach in order to avoid any conflict between important de-sulfurization programs and an LCFS.

The scenarios in this report incorporate several important assumptions about the federal RFS. First, all scenarios in this report assume that the Northeast receives a proportional share, based on population, of the advanced biofuels required nationally under the RFS. If the several types of fuel mandated by the RFS are disproportionately distributed to one region of the county (e.g., if the Northeast were to get more or less than its proportional share of the national supply any one type of biofuel), the result could be to increase or decrease the impact of the RFS on the region's AFCI. Second, we assume that the RFS-mandated advanced biofuels will be commercially available in substantial volumes within the next decade. While biofuel production technologies have made promising advances, it is far from certain that these types of fuels will be commercialized so quickly. Finally, we assume that no additional changes are made to the RFS between its adoption in 2007 and our target scenario year of 2020. Given the above assumptions, NESCCAF estimates the impact of the RFS in the Northeast will be to lower the gasoline AFCI by 3 percent, and the diesel AFCI by 1 percent.

The NESCCAF assumptions for the region's 2005 baseline fuels mix and 2020 business-as-usual projected fuels mix are summarized below in Table 3-2.

Table 3-2. Fuel and Fleet Volumes for Baseline and Business-as-Usual Conditions

	2005 Baseline	**2020 Business-as-Usual**
RBOB (Bgal)	17	18
Ethanol (Bgal)	0.52	2.8
Highway Diesel (Bgal)	4.0	4.5
Nonroad Diesel (Bgal)	1.1	1.1
No.2 Heating Oil (Bgal)	4.1	3.5
Biodiesel (Mgal)	0	240
Light-Duty Vehicles (x10^6)	28	36

3.2.2. Gasoline

We developed three gasoline scenarios. The first, scenario G1, considers aggressive penetration of PHEVs and EVs into the region's light-duty fleet, and assumes that these vehicles will be charged with electricity that has a CI equal to that of the region's average generation mix in 2005. In addition, scenario G1 envisions 900 million gallons of very advanced ethanol, achieving a CI of 0 g/MJ, displacing 600 million gallons of gasoline in the region. The second scenario, G2, is similar to G1 but assumes a lower CI for electricity, equal to that of the projected average grid in 2020, and assumes 1.5 billion gallons of less-advanced ethanol with a CI of 48 g/MJ, displacing 1 billion gallons of gasoline. Note that the ethanol in scenario G2 achieves a carbon intensity that is 50 percent lower than gasoline, consistent with the RFS2 requirement for "advanced" ethanol. Finally, scenario G3 illustrates a 10 percent CI reduction achieved solely through the use of electric-drive vehicles, with a very aggressive deployment of 4 million PHEVs and 2 million EVs, assuming the same CI for electricity as in scenario G2. The key elements of each gasoline scenario are summarized below in Table 3-3. The volumes and CI reduction percentages for each fuel type are presented in Figures 3-3, 3-4, and 3-5 and Tables 3-4, 3-5, and 3-6.

Table 3-3: Summary of Fuel and Vehicle Volumes for Gasoline Compliance Scenarios

Scenario	G1	G2	G3
EV Fleet Penetration	4.4%	4.4%	5.8%
Total Number of EVs (x1000)	1,600	1,600	2,100
PHEV Fleet Penetration	4.4%	4.4%	11%
Total Number of PHEVs (x1000)	1,600	1,600	3,900
Total Electricity Demand from PHEV/EVs (GWh)	14,000	14,000	22,000
Electricity Generation Mix	2005 Average	2020 Average with RPS and RGGI	2020 Average with RPS and RGGI
Total Volume of Advanced Ethanol (billion gallons)	0.9	1.5	-
Advanced Ethanol Carbon Intensity	0 g/MJ	48 g/MJ	-

As formerly noted, the assumed availability in Scenario G1 of 900 million gallons of zero CI ethanol is highly optimistic. NESCCAF's analysis suggests that ethanol produced via cellulosic fermentation of woody biomass can in theory achieve a carbon intensity of near-zero, and that limited production of suitable feedstocks is possible within the Northeast. However, cellulosic conversion technologies have not yet been demonstrated on a commercial scale. Moreover, the volume of zero carbon intensity fuel assumed in Scenario G1 far exceeds the 300 million gallons per year that NESCCAF estimates could be produced from regional woody biomass resources. Other zero-carbon-intensity fuels from inside or outside the region would therefore be necessary to provide the AFCI benefit shown in Scenario G1.

The use of electricity in all three scenarios depends upon the existence of significant numbers of electric-drive vehicles in the 2020 fleet. A vehicle's fleet share in a given year is a function of its sales in prior years and of the turnover rate of the rest of the fleet. For a particular vehicle type to reach a target percentage of the fleet, it would have to be available for sale some number of years before the target year. For all scenarios, we assumed that no significant sales of EVs or PHEVs occur before 2011, and that sales increase linearly from that year until 2020 for each scenario (thus for every scenario, market share in 2011 is equal to one-tenth the 2020 target value). In scenarios G1 and G2, 4.4 percent fleet share in 2020 is the result of sales increasing from 1.2 percent of the market in 2011 to 12 percent of the market in 2020. For Scenario G3, the 6 percent fleet share for EVs assumes that sales increase from 1.6 percent of the market in 2011 to 16 percent of the market in 2020; similarly, the 11 percent fleet share for PHEVs is the result of a sales share increase from 3 percent in 2011 to 30 percent in 2020.

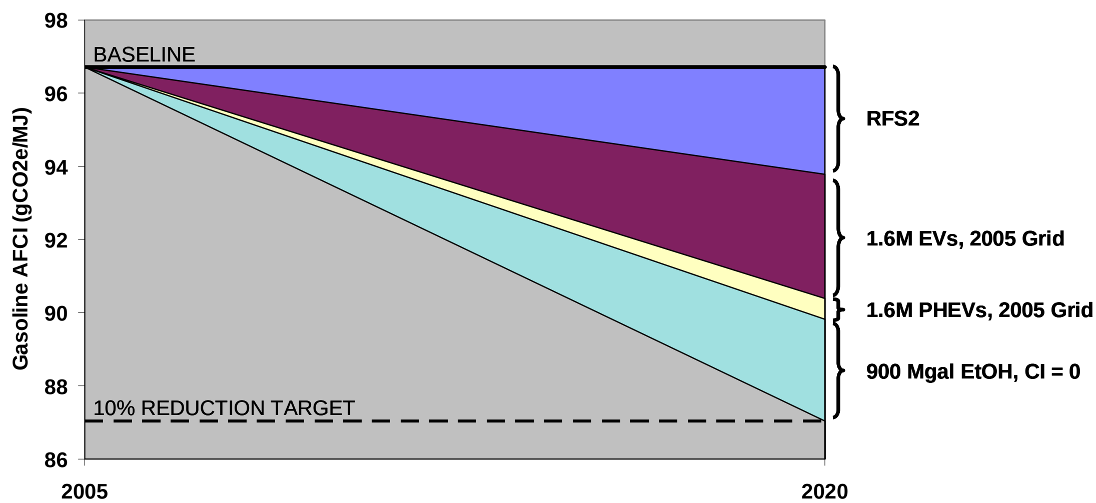


Figure 3-3. Illustration of Fuel Volumes Required for Scenario G1

Table 3-4. Key Assumptions for Scenario G1

Measure	CI Reduction	Key Assumptions
RFS2	3.0%	• Assumes Northeast receives proportional share of federally mandated biofuel volumes: o 1.3 Bgal cellulosic ethanol o 0.3 Bgal "advanced" ethanol o 0.2 Bgal "new" conventional ethanol
1,600,000 EVs 2005 Grid	3.5%	• Assumes 4.4% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 1.2% in 2011 to 12% in 2020 • Assumes Energy Economy Ratio (EER) = 4.0 • Assumes 2005 average generation mix • Total electricity demand = 10,000 GWh
1,600,000 PHEVs 2005 Grid	0.6%	• Assumes 4.4% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 1.2% in 2011 to 12% in 2020 • Assumes Energy Economy Ratio (EER) = 2.4 • Assumes 2005 average generation mix • Total electricity demand = 4,000 GWh
900 Mgal Ethanol, CI = 0.0	2.9%	• Ultra-low-carbon ethanol with zero carbon intensity. • CI is theoretically achievable through cellulosic fermentation of regionally available woody biomass. • 300 million gallons estimated available regional biomass capacity (600 million gallons must come from outside region)

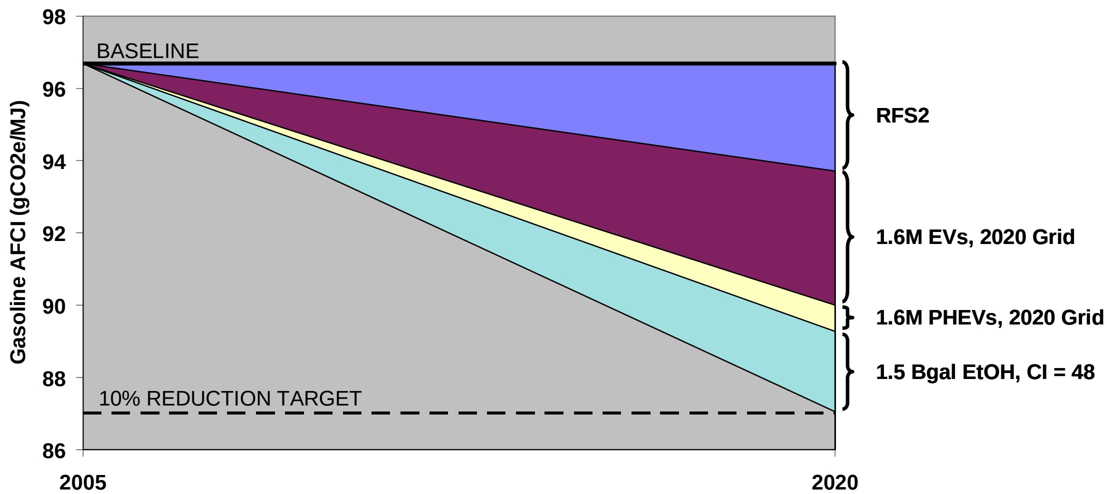


Figure 3-4. Illustration of Fuel Volumes Required for Scenario G2

Table 3-5. Key Assumptions for Scenario G2

Measure	CI Reduction	Key Assumptions
RFS2	3.0%	• Assumes Northeast receives proportional share of federally mandated biofuel volumes: o 1.3 Bgal cellulosic ethanol o 0.3 Bgal "advanced" ethanol o 0.2 Bgal "new" conventional ethanol
1,600,000 EVs 2020 Grid	3.8%	• Assumes 4.4% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 1.2% in 2011 to 12% in 2020 • Assumes Energy Economy Ratio (EER) = 4.0 • Assumes 2020 average generation mix • Total electricity demand = 10,000 GWh
1,600,000 PHEVs 2020 Grid	0.8%	• Assumes 4.4% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 1.2% in 2011 to 12% in 2020 • Assumes Energy Economy Ratio (EER) = 2.4 • Assumes 2020 average generation mix • Total electricity demand = 4,000 GWh
1.5 Bgal Ethanol, CI = 48	2.3%	• CI is 50% lower than for gasoline, equivalent to RFS2 "advanced" biofuel category • Could be from sugarcane, cellulosic, or other feedstocks • 300 million gallons already expected under RFS2 • 300 million gallons from estimated available regional biomass • 600 million gallons comes from outside region

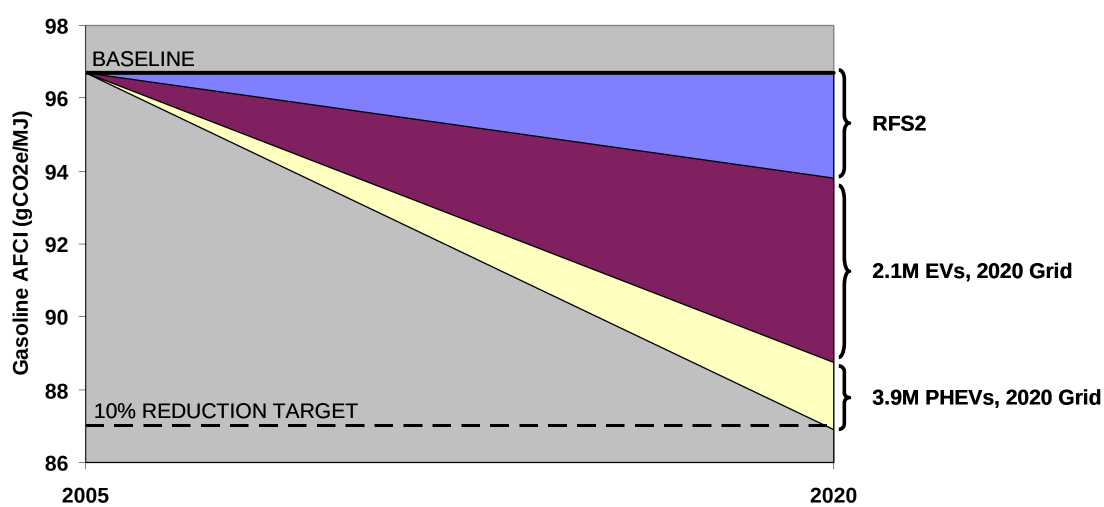


Figure 3-5. Illustration of Fuel Volumes Required in Scenario G3

Table 3-6. Key Assumptions for Scenario G3

Measure	CI Reduction	Key Assumptions
RFS2	3.0%	• Assumes Northeast receives proportional share of federally mandated biofuel volumes: o 1.3 Bgal cellulosic ethanol o 0.3 Bgal "advanced" ethanol o 0.2 Bgal "new" conventional ethanol
2,100,000 EVs 2020 Grid	5.2%	• Assumes 6% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 1.6% in 2011 to 16% in 2020 • Assumes Energy Economy Ratio (EER) = 4.0 • Assumes 2020 average generation mix • Total energy demand = 13,000 GWh
3,900,000 PHEVs 2020 Grid	1.8%	• Assumes 11% of light-duty fleet achieved by increasing market share (annual percentage of light-duty vehicle sales) from 3% in 2011 to 30% in 2020 • Assumes Energy Economy Ratio (EER) = 2.4 • Assumes 2020 average generation mix • Total electricity demand = 9,000 GWh

3.2.3. Diesel

Two hypothetical compliance scenarios are also presented for the diesel baseline. Scenario D1 envisions a 10 percent reduction being achieved solely through the use of advanced biodiesel with a carbon intensity of 20 g/MJ. In Scenario D2, a combination of natural gas and biodiesel is used. Key elements of each diesel scenario are summarized in Table 3-7. The volumes and CI reduction percentages for each fuel type are presented in Figure 3-6 and Figure 3-7.

The diesel scenarios assume that over one billion gallons of advanced biodiesel will be available in 2020 to the Northeast. As with the assumptions for advanced ethanol penetration already presented in the discussion of gasoline scenarios, an expectation of large-scale penetration of low carbon biofuels, while possible, remains very optimistic.

Table 3-7. Summary of Fuel Volumes for Diesel Compliance Scenarios

Scenario	D1	D2
Total Volume of Biodiesel (million gallons)	460 Highway 380 Nonroad	460 Highway 250 Nonroad
Biodiesel Carbon Intensity	20 g/MJ	20 g/MJ
Biodiesel Market Shares	10% Highway 15% Nonroad	10% Highway 10% Nonroad
Total Volume of Natural Gas (mscf)	-	62,000 Highway 26,000 Nonroad
Natural Gas Market Shares	-	10% Highway 10% Nonroad

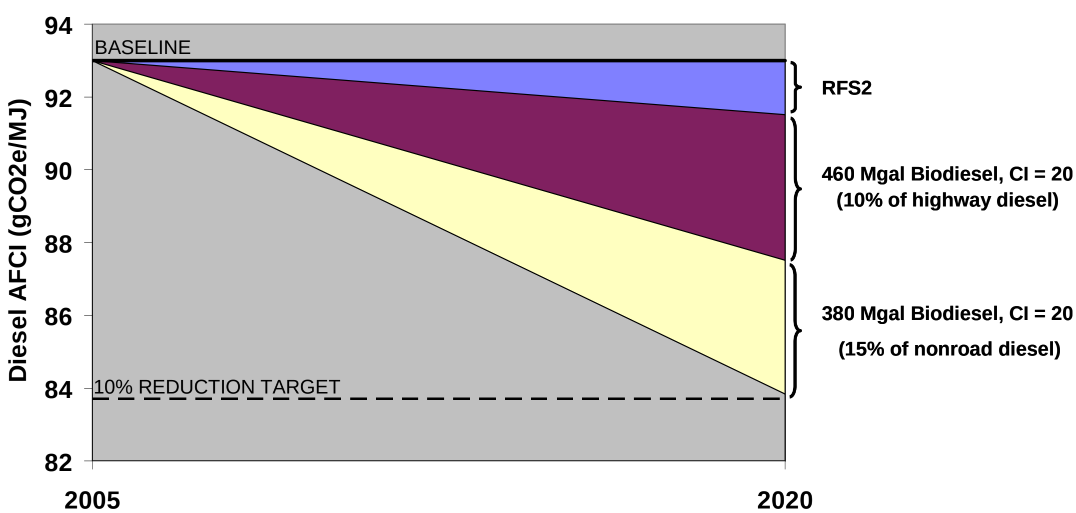


Figure 3-6. Illustration of Fuel Volumes Required for Scenario D1

Table 3-8. Key Assumptions for Scenario D1

Measure	CI Reduction	Key Assumptions
RFS2	1.6%	• Assumes Northeast receives proportional share of federally mandated biofuel volumes: o 240 Mgal of Biodiesel with CI 50% lower than for diesel
460 Mgal Biodiesel, CI = 20 (10% of highway diesel)	4.3%	• Assumes 10% of highway diesel energy demand met with advanced biodiesel • CI is 80% lower than for ULSD • CI is theoretically achievable through conversion of waste materials or other advanced processes • Estimated total neat biodiesel production from regional waste feedstocks = 6.7 Mgal
380 Mgal Biodiesel, CI = 20 (15% of nonroad diesel)	4.0%	• Assumes 15% of nonroad diesel energy demand met with advanced biodiesel • CI is 80% lower than for ULSD • CI is theoretically achievable through conversion of waste materials or other advanced processes • Estimated total neat biodiesel production from regional waste feedstocks = 6.7 Mgal

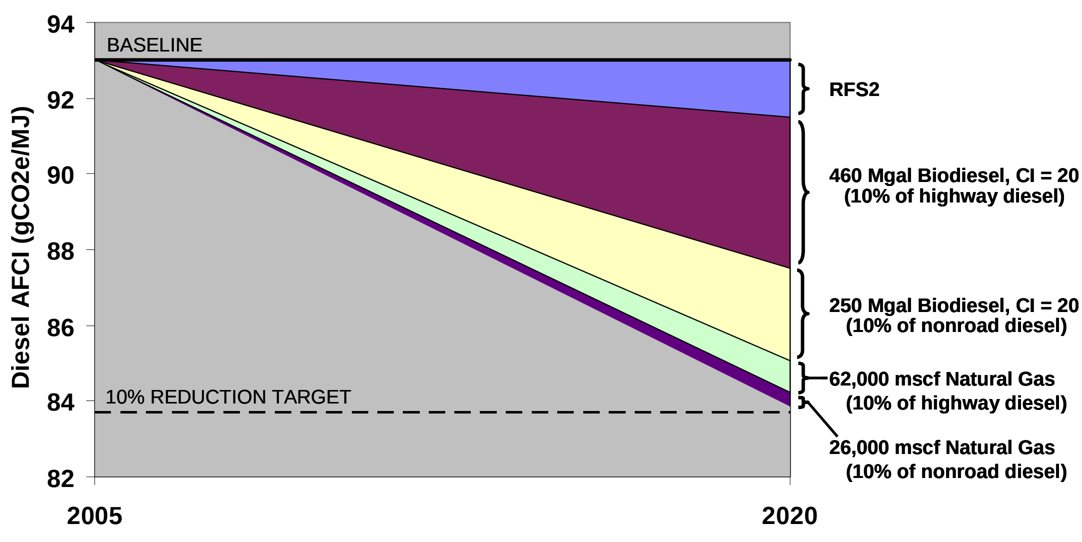


Figure 3-7. Illustration of Fuel Volumes Required for Scenario D2

Table 3-9. Key Assumptions for Scenario D2

Measure	CI Reduction	Key Assumptions
RFS2	1.6%	• Assumes Northeast receives proportional share of federally mandated biofuel volumes: o 240 Mgal of biodiesel with CI 50% lower than for diesel
460 Mgal Biodiesel, CI = 20 (10% of highway diesel)	4.3%	• Assumes 10% of highway diesel energy demand met with advanced biodiesel • CI is 80% lower than for ULSD • CI is theoretically achievable through conversion of waste materials or other advanced processes • Estimated total neat biodiesel production from regional waste feedstocks = 6.7 Mgal
250 Mgal Biodiesel, CI = 20 (10% of nonroad diesel)	2.6%	• Assumes 10% of nonroad diesel energy demand met with advanced biodiesel • CI is 80% lower than for ULSD • CI is theoretically achievable through conversion of waste materials or other advanced processes • Estimated total neat biodiesel production from regional waste feedstocks = 6.7 Mgal
62,000 Mscf Natural Gas (10% of highway diesel)	0.9%	• Assumes 10% of highway diesel energy demand met with natural gas • CI for compressed natural gas = 73.1 gCO_2e/MJ • Would require substantial fleet penetration of heavy-duty natural gas vehicles
26,000 Mscf Natural Gas (10% of nonroad diesel)	0.4%	• Assumes 10% of nonroad diesel energy demand met with natural gas • CI for compressed natural gas = 73.1 gCO_2e/MJ • Would require substantial fleet penetration of nonroad natural gas engines

3.2.4. Overview of Methods

For this analysis, NESCCAF: (1) estimated Northeast-specific lifecycle carbon intensity for selected fuels; (2) projected fuel and energy demand for transportation and home heating in the baseline and future scenario years; and (3) calculated fleet-average carbon intensity under selected scenarios for fleet penetration of alternative vehicle technologies (such as electric and plug-in hybrid-electric vehicles) and use of advanced fuels (such as low carbon ethanol).

To develop illustrative LCFS compliance scenarios, NESCCAF utilized three models: GREET,[20] VISION-NE, and a NESCCAF AFCI Calculator. Brief descriptions of each model follow; more detailed information is provided in Appendix A.

[20] Greenhouse Gases, Regulated Emissions, and Energy in Transportation. Spreadsheet model developed and maintained by Argonne National Laboratory.

The GREET model calculates lifecycle GHG emission factors for numerous conventional and alternative fuels. To facilitate the use of GREET for this project, NESCCAF worked with Life Cycle Associates, LLC to develop a set of Northeast-specific inputs and a specialized GREET Interface Tool (GIT). (See Appendix B for a detailed description of GIT). The results for selected fuel pathways are shown below in Table 3-10. The first two pathways listed, reformulated gasoline blendstock (technically referred to as reformulated blendstock for oxygenate blending (RBOB)) and ultra-low-sulfur diesel (ULSD), represent the primary conventional fuels used in highway gasoline and diesel engines in the baseline year.

Table 3-10. Carbon Intensity (CI) Scores for Selected Fuel Pathways

Fuel Pathway	Carbon Intensity (gCO_2e/MJ)*
Reformulated gasoline blendstock (RBOB)	96.7
Ultra-Low-Sulfur Diesel (ULSD)	93.0
Denatured Corn Ethanol	72.6
Soy Biodiesel	35.1
Compressed Natural Gas	73.1
Liquefied Natural Gas	78.0
Conventional gasoline	92.7
Tar sands RBOB	108
Tar sands ULSD	105
Liquefied petroleum gas (LPG)	86.9
Natural gas for heating	71.1
ULSD for heating	91.2
Woody biomass pellets	19.8
Woody biomass Ethanol: (Fermentation)	-1.7
Woody biomass Ethanol: (Gasification)	11.5
Electricity (100% NG)	181
Electricity (100% Coal)	345
Electricity (100% Renewables)	0
**Does not include effects of indirect Land Use Change*	

The second model used in this analysis, VISION-NE, projects transportation energy demand for the Northeast's vehicle fleet. NESCCAF developed this customized version of Argonne National Laboratory's VISION fleet turnover model for the specific purpose of characterizing the region's transportation energy demand under various scenarios. Finally, because an LCFS requires information about the specific carbon intensity as well as quantity of different types of fuels in the overall fuel mix, we developed an AFCI Calculator Tool that incorporates the GREET carbon intensity values and VISION-NE energy demand projections for different scenarios.

The use of the three tools is illustrated in Figure 3-8, which depicts a three-step calculation. First, the GREET model (via the GREET Interface Tool) calculates lifecycle carbon emission factors for each fuel type or pathway. Second, VISION projects the amount of each fuel required to meet transportation and heating demand in the Northeast. Third, and last, we use NESCCAF's AFCI Calculator to arrive at a weighted average of the carbon intensities of each fuel.

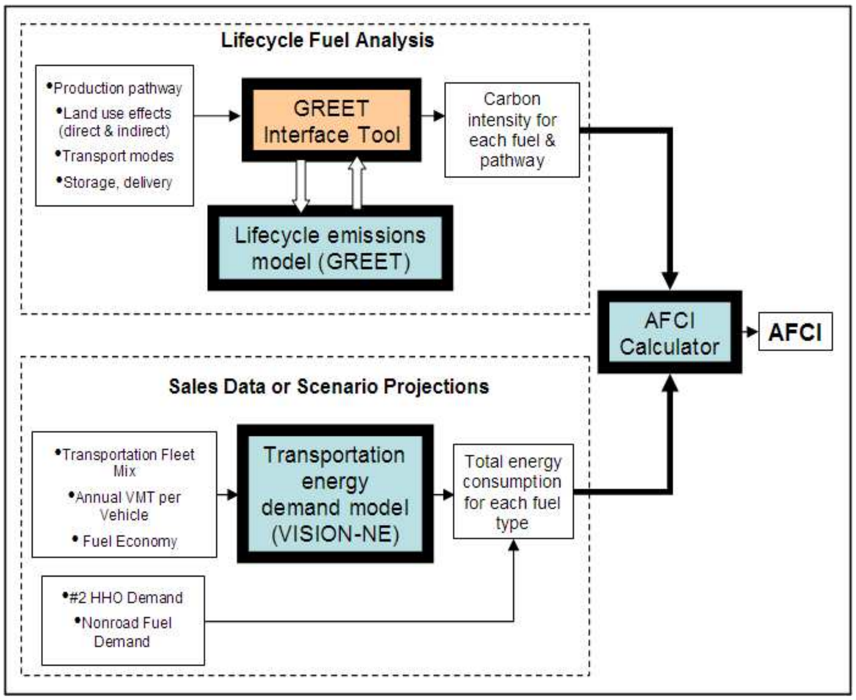


Figure 3-8. Modeling Tools Used in NESCCAF LCFS Scenario Analysis

3.3. Sensitivity of Results to the Carbon Intensity of Biofuels

Recent studies have suggested that when a comprehensive lifecycle assessment is applied to conventional biofuels such as corn-based ethanol, their carbon benefit may be substantially lower than previously thought, and could in fact be negative. At the time of this writing, additional research is being performed to understand the role of land use change on the lifecycle GHG intensity of fuels derived from agricultural and woody biomass feedstocks. The outcome of this research is likely to provide greater certainty about the carbon impacts of certain biofuels in the future.

3.3.1. Ethanol

Uncertainty about the influence of land use change on the lifecycle carbon intensity of certain biofuels has important implications not just for the effectiveness of possible compliance strategies, but also for the baseline AFCI score from which reductions are measured. Corn ethanol has been used throughout the Northeast as a blended oxygenate in commercial gasoline since 2004.[21] If blended ethanol is found to have a carbon intensity that is different from that of gasoline (either lower or higher), the region's baseline gasoline AFCI would be affected for 2004 and subsequent years. This, in turn, could affect the difficulty of meeting a particular AFCI reduction target.

For the scenarios presented in this report, we have assumed that the baseline fuel carbon intensity is equal to that of RBOB at 96.7 gCO_2e/MJ. Any new ethanol introduced to the Northeast's fuel supply would therefore need a lifecycle carbon intensity lower than 96.7 gCO_2e/MJ to make a contribution toward meeting an LCFS. The range of uncertainty regarding the lifecycle carbon intensity of conventional ethanol is currently quite large: some maintain that historical estimates of lifecycle carbon intensity in the neighborhood of 73 gCO_2e/MJ are valid, while others argue that the actual value could be many times that number.

In February 2009, CARB proposed a value of 30 gCO_2e/MJ (CARB 2009) to account for a net *increase* in carbon emissions associated with land use change induced by expanded ethanol feedstock production. This figure would be added to any carbon intensity values for corn ethanol that do not include indirect land use impacts, such as the 73 gCO_2e/MJ figure listed in Table 3-10. CARB's figure is a mid-range estimate, as its research indicated that GHG impacts from land use change could vary from 20 gCO_2e/MJ to 88 gCO_2e/MJ (CARB 2008). Thus, based on the GREET value of 73 g/MJ for direct effects, iLUC could increase corn ethanol's total lifecycle CI to 93–160 gCO_2e/MJ. Importantly, if land use change from corn is at the low end of this range, the total CI for ethanol would be lower than that of RBOB; however, if the land use change impact is found to be higher than 25g/MJ, corn ethanol would have a higher CI than RBOB.

Figure 3-9 illustrates the sensitivity of the gasoline AFCI to the carbon intensity of ethanol, showing the CI for an E10 (10 percent ethanol, 90 percent RBOB) blend under varying assumptions for the CI of ethanol used for blending.

[21] See Appendix C for a discussion of the phase-in of ethanol in the region.

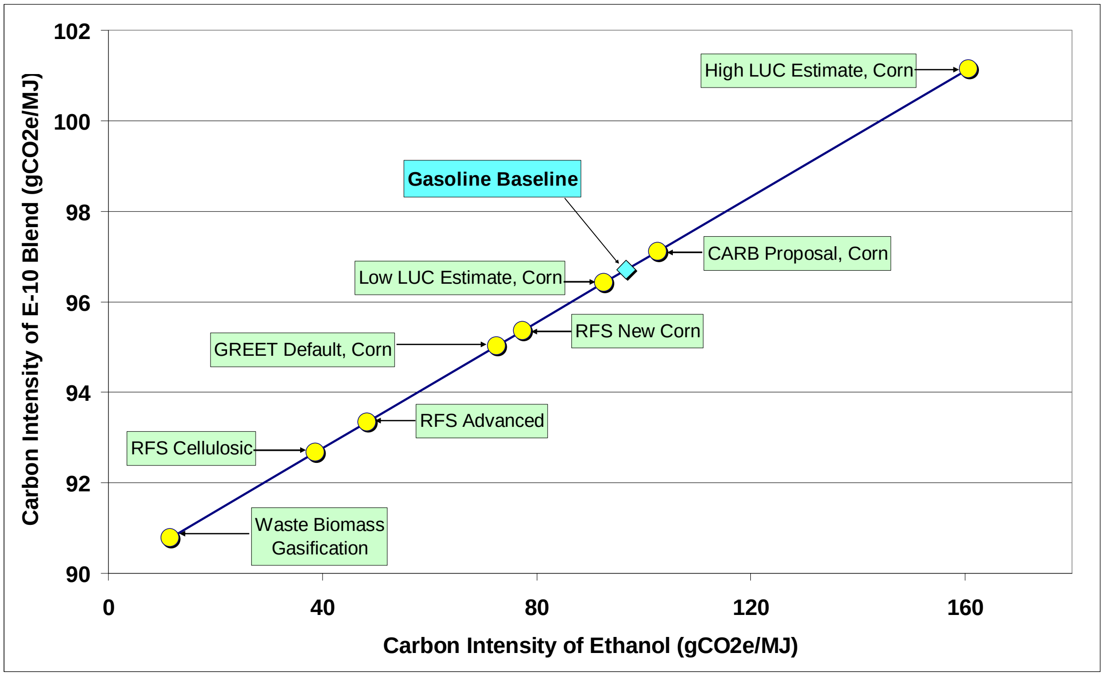


Figure 3-9. Sensitivity of E-10 CI to Ethanol CI

3.3.2. Biodiesel

Until recently, soy biodiesel was considered to be the most likely substitute for diesel fuel in transportation sources. However, as with corn ethanol, an ongoing debate among experts on the effect of indirect land use change has resulted in considerable uncertainty about the true lifecycle carbon intensity of soy biodiesel. As with ethanol and the gasoline AFCI, the usefulness of biodiesel in reducing the diesel AFCI is dependent on the lifecycle carbon intensity of the biodiesel itself. Figure 3-10 below shows the carbon intensity for B20 (20 percent biodiesel, 80 percent ULSD) under varying assumptions for the CI of the biodiesel used for blending.

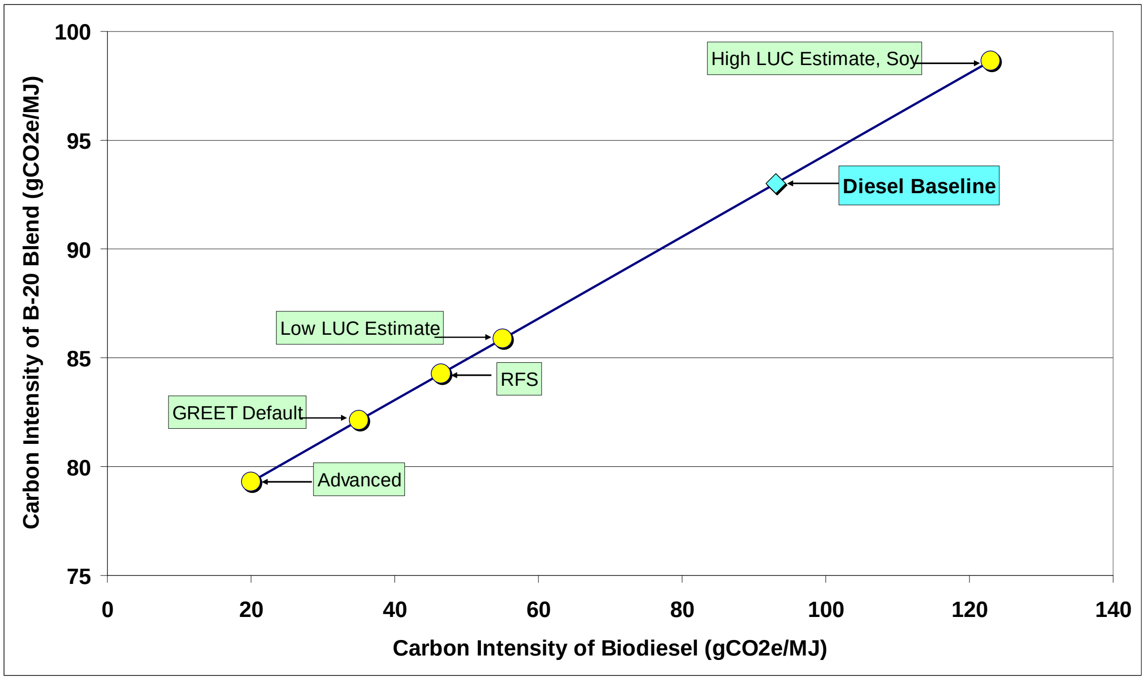


Figure 3-10. Sensitivity of B-20 Carbon Intensity to Biodiesel Carbon Intensity

As discussed in Section 3.2, at the time this analysis was conducted there was not yet consensus with respect to the effect of indirect land-use change on the carbon intensity of crop-based biofuels. On one hand, given that production of soy biodiesel requires more land per unit of fuel energy produced than does corn ethanol, it is possible that any land use change effect that exists for corn would be even more pronounced for soy biodiesel. On the other hand, the co-products of soybean production tend to be of higher value than those for corn, which could lessen or even negate any detriment associated with indirect land-use change caused by soy biodiesel production. To illustrate the scale of the possible AFCI impact if land use change effects are found to be applicable, Figure 3-10 includes "high" and "low" cases for land use change effects. We assumed for this analysis that these effects were equivalent to those found by CARB for corn ethanol (CARB 2009), as discussed in the previous section. We emphasize that these values are not intended to be predictive of any outcome of the current debate or of the actual land use change effect on the carbon intensity of biodiesel. Rather, they are presented to illustrate the potential roles that biodiesel might play in light of the ongoing discussion.

3.4. Electricity as a Low Carbon Fuel

The carbon intensity of electricity used in electric-drive vehicles depends on the mix of generating technologies that provide electricity for battery charging, on the efficiencies of the vehicle itself, and the conventional vehicle that the electric vehicle is displacing. For this analysis, we used CARB's draft Energy Economy Ratios (EER) of

4.0 for EVs and 2.4 for PHEVs.[22] We then calculated the efficiency-adjusted carbon intensity for electricity with two different generation mixes: the 2005 average generation mix and a projected 2020 average generation mix that assumes full implementation of the Regional Greenhouse Gas Initiative (RGGI) and relevant state Renewable Portfolio Standards.[23]

The scenarios presented in this report are intended to illustrate important dynamics at play in the design and implementation of an LCFS – they should not be taken to suggest the readiness of any particular technology. Because the attractiveness of EV/PHEV technology as an LCFS compliance option depends heavily on technologies that have not matured commercially, and on consumer attitudes and behaviors that have not yet been tested, the results presented here are highly uncertain. While NESCCAF's assumptions for EV/PHEV charging behavior and grid mix are plausible, by no means do they represent the only set of plausible assumptions. With advances in vehicle design, which could result in higher EERs than those assumed in this analysis, EVs and PHEVs may deliver a greater CI reduction than is assumed here. If that turns out to be the case, then fewer electric-drive vehicles will be needed in order to meet a given CI reduction target. However, if the fleet penetration rates envisioned in these scenarios turn out not to be feasible due hurdles in technology development, deployment of charging infrastructure, cost, or consumer attitudes, or if sufficient low carbon generating technologies are not available, electric-drive vehicles will be a less effective strategy for LCFS compliance.

3.4.1. Energy Economy Ratio

Electricity at the plug is a very high-quality energy type, ready for immediate and efficient conversion to motive power. On the other hand, liquid transportation fuels are of inherently lower quality since their chemical potential energy must still be converted to useful energy through a process that invariably involves significant losses. Thus, for example, a megajoule of liquid fuel "at the pump" is less useful than a megajoule of electricity "at the plug." This difference in energy quality is reflected in the superior energy economy of electric-drive vehicles compared to liquid-fueled vehicles – an EV will travel a greater distance per unit of energy input than will a comparable gasoline-powered vehicle.

Because the objective of a low carbon fuels program is to displace conventional, high-carbon fuels with low carbon substitutes, it is important to know the amount of gasoline that would be displaced if a consumer were to switch from a conventional vehicle to an EV. If we assume that this consumer's travel demand is fixed (i.e., that s/he desires to travel a set distance regardless of the type of car s/he is using), then the amount of displaced gasoline energy would be equal to the energy consumed by the EV multiplied by the ratio of the EV energy economy (in miles per gasoline-gallon equivalent or mpgge) to the fuel economy of the gasoline vehicle (in miles per gallon).

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[22] These were CARB's most recent draft values at the time NESCCAF conducted its analysis. CARB has since revised these EER values, proposing a single EER of 3.0 for both EVs and PHEVs.

[23] RGGI is a regional cap-and-trade program that caps CO_2 emissions from electricity generation plants larger than 25 MW in ten states. RGGI went into effect in January 2009, and requires a 10 percent reduction in emissions from 2006 levels by 2018.

This ratio has been defined by CARB as the Energy Economy Ratio (EER) (CARB 2009). At the time of this analysis, CARB had published draft EER values of 4.0 for battery-electric vehicles (BEVs) and 2.4 for PHEVs.

NESCCAF adopted these draft EER values for the scenario analyses developed for this report. We further assumed that use of electric-drive vehicles would displace use of average conventional vehicles – therefore the average energy economy of these vehicles would be 4.0 or 2.4 times the fleet average fuel economy as determined by the federal CAFE standards.[24] Because the carbon intensity is a measure of emissions per unit of energy consumed, it follows that the *effective* carbon intensity of electricity used in transportation would be equal to the CI of the grid (see below) divided by the EER. An expanded discussion of the rationale for and implications of the EER is provided in Appendix A.

3.4.2. Carbon Intensity of Electricity for Electric-Drive Vehicles

The carbon intensity of electricity used to charge electric-drive vehicles is dependent on a variety of factors, including the composition of different electricity generating plants (e.g., coal, natural gas, or nuclear) that provide electricity to the grid, and how much and when each of these electricity generation plants are used. At present, most electricity demand serves needs other than electric vehicles. But as these vehicles begin to be deployed, they might begin to change the way that electricity is generated and dispatched. Factors that will determine the extent to which electric vehicles will affect the carbon intensity of the grid include the design of the vehicles (e.g., battery size and charging voltage), how consumers use the vehicles (e.g., how frequently and at what time of day the consumer chooses to plug in), as well as the total number of electric-drive vehicles in the fleet.[25] Because there has been virtually no commercial experience with these vehicle technologies to date, it is very difficult to predict the precise way in which consumers will use PHEVs, and thus the appropriate grid mix that will accompany their use. To illustrate the range of possible values, we have calculated electricity carbon intensity for each major generation type and for the average grid mix in the 2005 baseline year and as projected in 2020. As discussed in Chapter 5, the marginal generating technology or mix for a given charging event is likely to differ from the average mix.

Table 3-11 below shows the current mix of electricity generation in the Northeast, and the projected 2020 generating mix which includes the effects of RGGI and state-specific Renewable Portfolio Standards. NESCCAF generated these grid projections

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[24] In practice, the EER is likely to vary from one vehicle to the next, and possibly even from one user to another for a given vehicle type. While it seems reasonable to assume that an EV in general would displace a conventional vehicle with similar design and performance parameters, it is possible that EVs, particularly those with limited range or cargo capacity, would be purchased as a second or third vehicle for a household and used only for selected purposes, such as short local trips. In this case, the EV would displace gasoline that might be used by a much larger vehicle, resulting in an effective EER that is much higher than average.

[25] See Chapter 5 for a discussion of the impact of charging time and power demand on grid mix, and the ability of the current and projected grid to accommodate substantial fleet penetration of these advanced vehicles.

using the NE-MARKAL model, which is a linear optimization model of the Northeast's energy system.[26]

Table 3-11. Current and Projected Sources of Electricity, NESCAUM Region

Source	2005 GWh	2005 Share	2020 GWh	2020 Share
Coal	54,200	16%	22,500	8%
Nuclear	103,000	31%	52,000	18%
Natural gas	105,000	31%	118,000	41%
Oil	31,900	10%	10,200	4%
Hydro	28,600	9%	20,900	7%
Renewable (non-hydro)	13,200	4%	67,500	23%
Total	335,000	100%	291,000	100%

As discussed above, the generation mix has a large impact on the carbon intensity associated with EVs and PHEVs. As Table 3-11 indicates, 26 percent of Northeast electricity in 2005 was produced with either coal or oil, which are the two most carbon-intense conventional generating fuels, while over 40 percent of total electric generation came from nuclear, hydro-electric and renewable sources, which are zero or low carbon generating technologies.

Figure 3-11 illustrates the sensitivity of electricity carbon intensity to EER and grid mix. The figure shows that all types of electricity will have a CI that is lower than the gasoline baseline when used to charge a vehicle with a 4.0 EER. When used in a vehicle with a 2.4 EER, however, electricity from both coal and oil result in a carbon intensity that is higher than that of gasoline. Even with the more efficient 4.0 EER EV, coal and oil offer only a slight improvement over gasoline, while natural gas, nuclear, and renewables (including hydro and many types of biomass) provide substantially lower CI compared to gasoline. It is clear from Figure 3-11 that shifting the grid mix from high-carbon to low carbon generating fuels, or applying some policy mechanism to ensure that EV/PHEV charging is tied directly to low carbon power, will enhance the effectiveness of electricity as an LCFS compliance option.

[26] Additional information on the NE-MARKAL model can be found at: http://www.nescaum.org/focus-areas/climate-and-energy/documents.

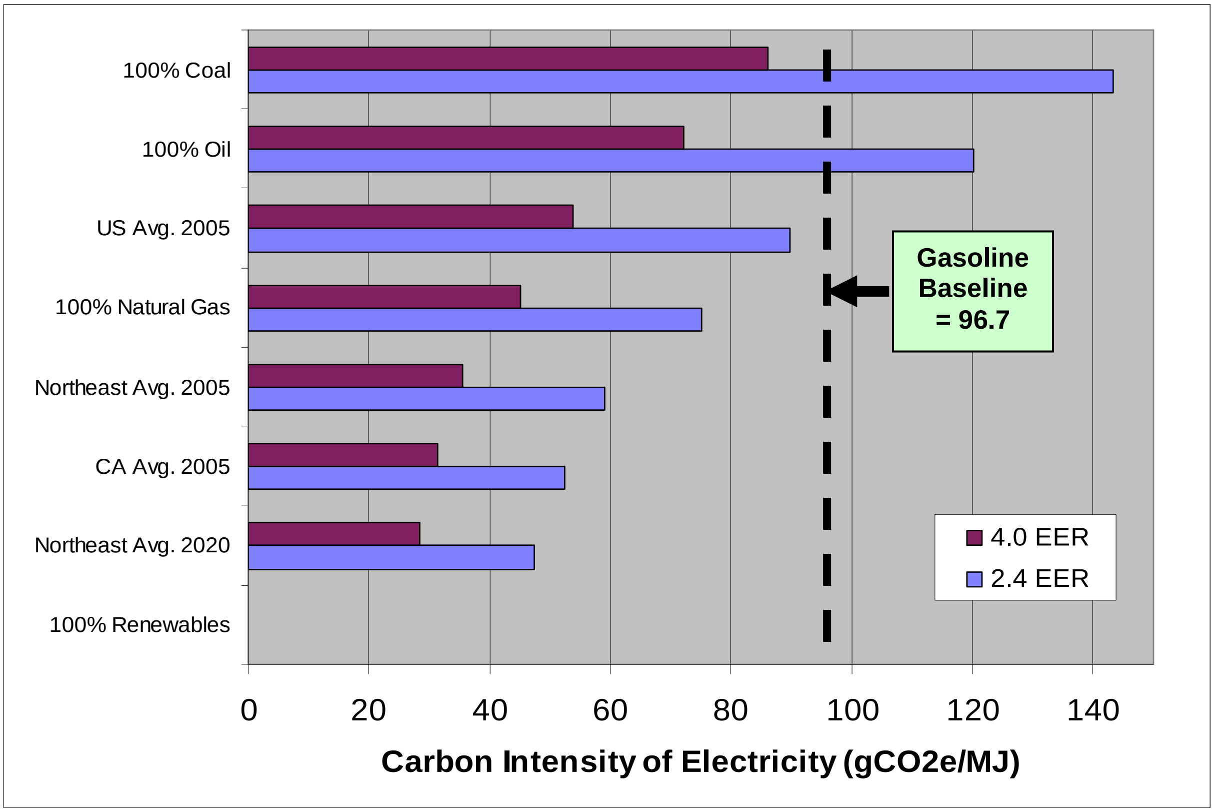

Figure 3-11. Carbon Intensity of Electricity with Different Generation Mixes and Energy Economy Ratios (EER)

3.4.3. Electricity Demand from Electric Vehicles

As mentioned above, the success of electric-drive vehicles as an LCFS compliance option depends not just on vehicle characteristics and driver behavior, but also on the availability of low carbon electricity for battery charging. Scenarios G1 and G2 envision over 3 million electric drive vehicles on the Northeast's roads by 2020, consuming 14,000 GWh.[27] Scenario G3 envisions roughly 6 million vehicles, with a total energy demand of around 22,000 GWh. These demand totals respectively represent around 4 percent and 7 percent of the total electricity demand in the Northeast in 2005. Chapter 5 of this report provides estimates of whether sufficient grid capacity exists to accommodate this demand. As mentioned above, the behavior of individual EV and

[27] VISION-NE calculates the electricity demand per vehicle based on user inputs for EER, and for plug-in hybrid vehicles, their all-electric range (AER). VISION-NE's calculated annual electricity demand per vehicle is 6,200 kWh for EVs and 2,300 kWh for PHEVs. Note that VISION-NE assumes that AER increases with each model year, so the numbers above are the fleet average, which is lower than for new vehicles in a given year.

PHEV owners will be an important factor in determining the capacity of the existing grid to accommodate significant numbers of electric-drive vehicles.

3.5. Conclusions from Scenario Analysis

- In 2005, approximately 17 billion gallons of gasoline, 500 million gallons of ethanol, and 4.0 billion gallons of diesel fuel were used to power light and heavy duty vehicles in the eight NESCAUM member states. In 2020 under a business-as-usual projection, NESCCAF estimates that the region's light and heavy vehicles will require 18 billion gallons of gasoline, 3 billion gallons of ethanol, and 4.5 billion gallons of diesel fuel.
- The federal RFS will require the use of approximately 17 billion gallons of advanced biofuels - as distinguished from conventional corn-ethanol and biodiesel - by 2020 nationwide. If this fuel is assumed to be distributed proportionally on a population basis throughout the United States, the Northeast could expect to receive approximately 2 billion gallons of low carbon biofuels by 2020 as a result of the RFS. If this is the case, the federal RFS by itself will produce a reduction of approximately 3 percent in the average carbon intensity of transportation fuel in the Northeast.
- There are a number of fuels and fuel pathways that could be used to comply with a regional LCFS. In the case of gasoline, a 10 percent reduction in overall carbon intensity could be achieved by introducing 4 billion gallons of advanced ethanol (with an RFS-compliant carbon intensity of 48 gCO_2e/MJ) in the region by 2020. This is in addition to the volume of advanced biofuels required by the Renewable Fuel Standard.
- Alternatively, an equivalent reduction could be achieved by increasing the fleet penetration of plug-in hybrid and all-electric vehicles to approximately 17 percent in the same timeframe (2 million all-electric and 4 million plug-in hybrid vehicles).
- Some combination of the above approaches or the use of advanced fuels that are not yet commercially available could also allow regulated entities to meet the LCFS.

For heavy-duty diesel vehicles, a 10 percent reduction in the carbon intensity of transportation diesel fuel in the 2020 timeframe will depend on the rapid commercialization and large-scale production of substantial quantities of low carbon diesel fuel substitutes. It could be met with the following approaches:

- The introduction of 800 million gallons of advanced biodiesel with a carbon intensity of 20 gCO_2e/MJ in addition to the fuel expected from the Renewable Fuel Standard.
- The introduction of 480 million gallons of advanced biodiesel (20 gCO_2e/MJ) and approximately 35 percent of heavy-duty vehicles operating on natural gas.
- The introduction of advanced fuels that are not yet commercially available.

Reducing the carbon intensity of transportation diesel by 10 percent in the 2020 timeframe could be more difficult than for gasoline, given that there are fewer apparent near-term replacement options for diesel fuel. For example, the light-duty plug-in hybrid and pure electric vehicles that are being developed for near-term commercial deployment could plausibly displace a considerable portion of the light-duty fleet. This study did not evaluate the impact on the carbon intensity of heavy duty vehicle fuel from the introduction electric drive systems for heavy duty vehicles. If commercial development proceeds, this approach could be an important contributor to reducing the carbon intensity of the heavy-duty vehicle fleet.

4. PROGRAM STRUCTURE

This chapter provides an overview of issues affecting the design of an LCFS for the northeast states and makes recommendations concerning specific program elements. The information in the chapter is based on: (1) an evaluation of the fuel supply and distribution network in the Northeast; (2) research into existing federal and state fuels program requirements; (3) a review of the LCFS program structure adopted by the California Air Resources Board; and (4) conversations with industry representatives.

Specifically, this chapter addresses the following program design elements:

1. Potential fuels for inclusion in a Northeast LCFS;
2. Baseline fuel characteristics;
3. Lifecycle fuel carbon tracking mechanisms; and
4. Determining which entities to regulate.

Where applicable, we describe California's LCFS program design to provide context for these issues.

4.1. Determining Regulated Entities

This section discusses which entities could potentially be regulated—that is, which entities would be "regulated parties"—under a Northeast LCFS. Several important factors must be taken into consideration, including: (1) ensuring regulated entities have the information they need to demonstrate compliance and report to regulators; (2) ensuring administrative feasibility; and (3) minimizing the regulatory burden associated with this program. In CARB's *Supporting Documentation for the Draft Regulation for the California Low Carbon Fuel Standard*, CARB states there are potential enforcement differences between the LCFS and current standards for liquid fuels, such as the RFG program. Compliance for the RFG program can be determined systematically through fuel sampling and testing. Unlike the RFG program, the LCFS regulates carbon intensity which – while based on measured properties – cannot be abstracted directly from the fuel or measured by analytical instruments. Therefore, the definition of regulated parties must take into consideration the availability of carbon intensity data and the extent to which the data are verifiable.

For gasoline (and biofuel blends), diesel (and diesel substitutes), CARB has proposed to regulate the producers of the fuel, the importers of fuel, or certain recipients (entities that take on the obligation of being the regulated entity). For other fuels, such as compressed natural gas, other parties are identified. CARB also proposed a provision that prohibits any party from adding or making modifications to transferred fuel unless that party has become the regulated entity under the LCFS, among other requirements (CARB 2009). In the instance that a producer or importer transfers ownership of fuel, the LCFS obligation can be transferred with the fuel if agreed upon by the parties. A key consideration for the northeast states is whether the fuel distribution system in the Northeast is similar enough to California's for the northeast states to regulate the same parties California is proposing to regulate.

4.1.1. Description of Northeast Fuel Distribution Network

Gasoline and diesel fuel sold in the Northeast passes through several facilities between the time it arrives in the region until it reaches retail outlets (gas stations, truck stops, nonroad and heating oil distributors). Approximately 50 percent of fuel arrives as crude oil and is refined in the region. Another 25 percent of fuel arrives as finished product (e.g., RFG, conventional gasoline, high and low sulfur diesel, heating oil). Finished gasoline is often blended with renewable fuels such as ethanol. Another 15 percent of the fuel used in the region is imported as unfinished product (RBOB and CBOB) that is further blended with an oxygenate, such as ethanol, before being sold to retailers in the region. No crude oil is extracted in the region – all of it is imported from different regions of the country or from other countries. This is illustrated by Table 4-1, which shows where crude oil and petroleum products used in the Northeast originate.

Table 4-1. Movement of Crude Oil & Petroleum Products into PADD 1 2005/2006 Annual Average – Millions of Gallons

Product	From PADD 2	From PADD 3	From Canada	From Other Foreign Source	Total
Crude	230.4 (1%)	120.3 (<1%)	3253.3 (13%)	20,530.7 (85%)	24134.7 (100%)
RFG	0	2464.7 (53%)	1153.2 (25%)	1038.7 (22%)	4656.7 (100%)
CG	239.4 (1%)	21,398.0 (80%)	273.2 (1%)	4857.8 (18%)	26768.4 (100%)
RBOB	1.1 (<1%)	1685.3 (42%)	723.7 (18%)	1595.3 (40%)	4005.4 (100%)
CBOB/GTAB	0	31.3 (<1%)	65.9 (1%)	4834.1 (98%)	4931.3 (100%)
HS Diesel & Fuel Oil	53.1 (1%)	3824.5 (60%)	574.6 (9%)	1926.4 30%)	6378.6 (100%)
LS Diesel	84.6 (1%)	7787.5 (79%)	834.6 (8%)	1187.4 (12%)	9894.1 (100%)
Ethanol (2006)	750.7 (60%)	0	6.1 (<1%)	491 (39%)	1247.8 (100%)

Sources: DOE 2006, 2007.

In many states in the Northeast and Mid-Atlantic, the fuel supply network is very different from that in California. Much of the transportation fuel used in California is extracted and/or refined in the state. Some states in the Northeast and Mid-Atlantic are similar to California in that the majority of fuel used in the state is refined in the state. In other states, most or all of the fuel used is not refined in the state. Because of this, the numbers and types of entities regulated in the Northeast and Mid-Atlantic may vary state to state. The Northeast may need to identify different regulated entities than California has, in order to ensure proper lifecycle GHG accounting for transportation fuels.

Many of the regulated entities under the California LCFS are already regulated under federal or California fuel programs. This may also be the case in the Northeast. Many of the northeast entities that may be regulated under a Northeast LCFS will likely be the same entities regulated under either the RFG or RFS programs. Table 4-2 provides numbers for different types of regulated entities in different states under the RFS. These would also likely need to be regulated under a Northeast LCFS.

Table 4-2. Obligated Parties under the Federal Renewable Fuels Standard

State	Refiners*	Importers	Companies
Connecticut	40	31	30
Delaware	12		6
Maine	14	18	11
Massachusetts	17	9	14
New Hampshire	3	8	2
New Jersey	204	84	69
New York	40	29	48
Pennsylvania**	11	7	11
Rhode Island	5	5	8
Vermont	0	5	4

**Refiners include non-renewable fuel blenders who finish gasoline*
***Only includes PA facilities in southeast corner of PA near New Jersey*

Some entities that handle transportation fuel in the Northeast are neither refiners nor importers. An example of such a facility is a terminal or a producer of renewable fuels. In some cases terminal owners own the fuel being transferred through the facility and in other cases terminal owners do not own the fuel handled in the facility. The facilities and entities that handle and process fuels before they reach the consumer include refiners, importers, blenders, and terminals. These are described below and their locations are shown graphically in Figure 4-1.

A **petroleum refinery** is a facility that produces petroleum products from crude oil; the most common products being gasoline, diesel and other distillate fuel oils, kerosene, residual fuel oil, asphalt, and lubricants. The products are produced at the refinery by distillation, cracking, or reforming of unfinished petroleum derivatives. Pursuant to the federal RFS, refiners are identified as **obligated parties**; meaning they must meet the volume obligations for renewable fuels. Under the federal RFS, the refinery definition is expanded to include facilities where blendstocks are combined to produce gasoline or diesel fuel or where blendstocks are added to finished gasoline or diesel fuel. Where the RFS identifies **blenders** as obligated parties, it is referring to these above-described blenders.

An **importer** is a person who imports gasoline, gasoline blending stocks or components, or diesel fuel from a foreign country into the United States. Under the federal RFS, an importer is a person who brings gasoline or renewable fuel into the 48 contiguous states from a foreign country or from an area of the United States that is not subject to the RFS. Importers of gasoline are deemed **obligated parties** under the federal RFS.

An **ethanol blending plant** is a type of refinery at which gasoline is produced solely through the addition of ethanol to gasoline, and at which the quality or quantity of gasoline is not altered in any other manner. These "refineries" are not deemed obligated parties under the federal RFS.

An **oxygenate blending facility** is any facility at which oxygenate is added to gasoline or blendstock, and at which the quality or quantity of gasoline is not altered in any other manner except for the addition of deposit control additives. These facilities are not deemed obligated parties under the federal RFS.

A **bulk gasoline terminal** is any gasoline storage and distribution facility that receives gasoline by pipeline, ship or barge, or cargo tank (i.e., delivery tank truck or railcar). For purposes of the federal National Emissions Standards for Hazardous Air Pollutants (NESHAP), a throughput cutoff of 20,000 gallons per day is used to distinguish the larger **gasoline terminals** from the smaller **bulk gasoline plants**. Typically, **bulk plants** receive a greater proportion of their product or exclusive delivery of their product via cargo tank delivery.

A **loading rack** (sometimes called a "distribution rack") refers to the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill delivery tank trucks.

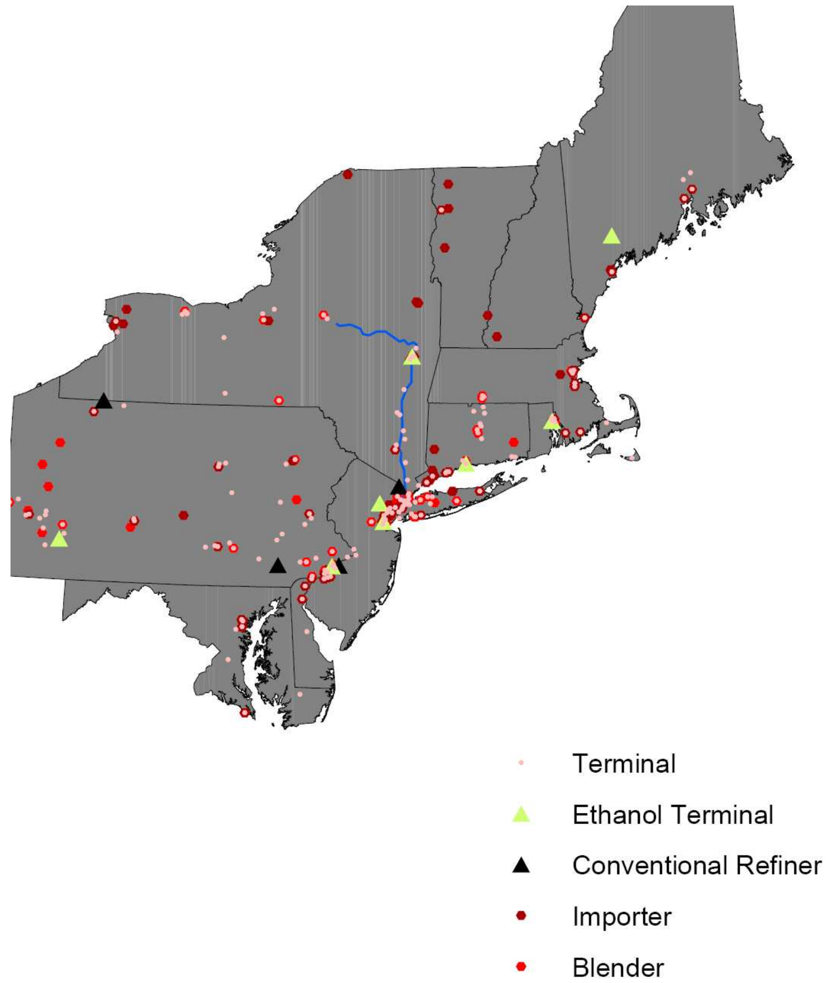

Figure 4-1. Schematic of Northeast Fuel Distribution System

To provide a sense of how many regulated entities there might be under a Northeast LCFS, numbers for different potentially regulated entities are provided: There are approximately 223 distribution racks operated by 145 companies and 203 companies operating 544 refineries and importer facilities in the Northeast. A detailed description of the types of facilities, their locations, and the Northeast's fuel distribution system is provided in Appendix C. Figure 4-1 provides the location for different types of facilities in the Northeast. The map shows a clustering of blenders, importers, and terminals in downstate New York and New Jersey and another concentration of facilities in southern New Jersey and in Pennsylvania.

4.2. Possible Tracking Mechanisms

Whether the regulated entity is the refiner, importer, blender, or terminal, or some combination of these entities, it will be necessary to estimate the carbon intensity of finished products. This requires a mechanism to assign carbon intensities to different types of fuel, along with a mechanism to track the different types of fuels sold. In this section, we discuss possible sources for this type of information and different tracking mechanisms, along with their strengths and shortcomings.

As background, we begin with a brief description of the tracking required under each federal regulation. Further detail is provided in Appendix C to this report. Table 4-3 summarizes the reporting requirements that are already in place under existing federal fuels programs.

Table 4-3. Summary of Reporting Requirements for Existing Federal Fuels Regulations

Regulation	Regulated entities	Requirements
RFS	Refiners, Importers, Blenders (proposed)	Renewable fuel volume required, renewable fuels identification numbers (RINs)
Conventional gasoline	Refiners	Total gallons produced or imported, applicable benzene emissions standard, sulfur content standard.
Reformulated gasoline	Refiners, Importers	Properties of fuel, batch number, date of production, volume of batch, grade of gasoline.
Mobile source air toxics	Importers	Reformulated gasoline toxics emissions performance averaging report, and other requirements.
Diesel fuel	Refiners, Importers	Volume of fuel produced (for each refinery or importer) for different sulfur levels.
Diesel sulfur: nonroad, locomotive, marine diesel fuel	Refiners, Importers	Volume of diesel fuel produced and designated, volume of heating oil produced, sulfur content of fuel.
Gasoline benzene program	Refiners, Importers	Benzene volume percent and volume of RFG, RBOB, and conventional gasoline, separately by batch, produced by the refinery or imported.
Gasoline sulfur	Refiners, Importers of gasoline	Applicable baseline, average standard, adjusted cap standard for selected years.

4.2.1. Renewable Identification Numbers

Under the proposed RFS (EPA 2009), renewable identification numbers or “RINs” are attached to each batch of renewable fuel sold. The RINs automatically transfer with each batch of renewable fuel. RINs are finally separated at the point the renewable fuel is blended with petroleum fuel; at that point they are retained by the final owner of the renewable fuel. Volumes of renewable fuel can be split or merged any number of times while remaining under the ownership of a single party, with no impact on RINs.

Each RIN is generated by the producer or importer of the renewable fuel and uniquely identifies not only a specific batch, but also every gallon in that batch. The RIN consists of a 38-character code. To implement the requirements of the EISA (requiring an increase, over time, in the use of advanced renewable fuels that achieve greater GHG reductions than current corn ethanol), EPA has designated one digit of the RIN to identify the type of fuel – based on the four categories of biofuels specified in the EISA legislation (called the “D” code of the RIN). The four categories of fuel and their corresponding GHG reduction are as follows: (1) renewable fuel that achieves a 20 percent GHG reduction from the baseline fuel; (2) advanced biofuels that achieve a 50 percent GHG reduction from the baseline fuel; (3) cellulosic biofuel that achieves a 60 percent GHG reduction from the baseline fuel; and (4) biomass based diesel that achieves a 50 percent GHG reduction from the baseline fuel. Under the LCFS, however, regulated entities will need to determine the actual carbon intensity of different fuels, rather than just which of these bins it qualifies for. Thus, additional information on lifecycle carbon emissions will be needed. As an example, take a diesel substitute developed from algae that reduces lifecycle GHG emissions by 65 percent. Under the RFS, this fuel would simply be registered as meeting at least a 50 percent GHG reduction standard. Alternatively, corn ethanol produced at existing facilities will be assumed under the RFS to have no effect (zero percent change) on GHG emissions, when in fact this fuel may have higher lifecycle GHG emissions than gasoline. There is no mechanism to account for these variations under the RFS.

To address this problem, CARB has developed lifecycle GHG estimates for different types of fuels and has proposed to allow regulated entities to use these values as default lifecycle GHG values in calculating the carbon intensity score of their fuel. Alternatively, regulated entities can provide supplementary information that, if approved by CARB, would allow for a modification of the default lifecycle GHG estimates. This basic approach can be summarized as follows:

1) Report based on default values;

2) Set conservative default values;

3) Provide look-up tables that regulated entities can use to identify default values;

4) CARB to establish default values using the revised GREET model.

In the case of ethanol, CARB proposed to establish different default values depending on the feedstock, feedstock origin, and processing characteristics of the fuel. Table 4-4 shows the potential default values that could be used. Defaults values would apply except where a producer could provide information showing that his fuel achieves greater GHG reductions.

Table 4-4. Proposed CARB Lookup Table for Carbon Intensity Values for Gasoline

Lookup Table for Carbon Intensity Values for Gasoline and Fuels that Substitute for Gasoline

Fuel	Pathway Description	Carbon Intensity Values (gCO_2e/MJ)		
		Direct Emissions	Land Use or Other Effect	Total
Gasoline	CARBOB – based on the average crude oil delivered to California refineries and average California refinery efficiencies	95.86	0	95.86
	CaRFG-CARBOB and a blend of 100% average Midwestern corn ethanol to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	96.09	---	96.09
	CaRFG-CARBOB and a blend of an 80% Midwestern average corn ethanol and 20% California corn ethanol (dry mill, wet DGS) to meet a 3.5% oxygen content by weight blend (approximately 10% ethanol)	95.85	---	95.85
Ethanol from Corn	Midwest average; 80% Dry Mill; 20% Wet Mill; Dry DGS	69.40	30	99.40
	California average; 80% Midwest Average; 20% California; Dry Mill; Wet DGS; NG	65.66	30	95.66
	California; Dry Mill; Wet DGS; NG	50.70	30	80.70
	Midwest; Dry Mill; Dry DGS, NG	68.40	30	98.40
	Midwest; Wet Mill, 60% NG, 40% coal	75.10	30	105.10
	Midwest; Dry Mill; Wet, DGS	60.10	30	90.10
	California; Dry Mill; Dry DGS, NG	58.90	30	88.90
	Midwest; Dry Mill; Dry DGS; 80% NG; 20% Biomass	63.60	30	93.60
	Midwest; Dry Mill; Wet DGS; 80% NG; 20% Biomass	56.80	30	86.80
	California; Dry Mill; Dry DGS; 80% NG; 20% Biomass	54.20	30	84.20
	California; Dry Mill; Wet DGS; 80% NG; 20% Biomass	47.40	30	77.40
Ethanol from Sugarcane	Brazilian sugarcane using average production processes	27.40	46	73.40
Compressed Natural Gas	California NG via pipeline; compressed in California	67.70	0	67.70
	North American NG delivered via pipeline; compressed in California	68.00	0	68.00
	Landfill gas (bio-methane) cleaned up to pipeline quality NG; compressed in California	11.26	0	11.26
Electricity	California average electricity mix	124.10	0	124.10
	California marginal electricity mix of natural gas and renewable energy sources	104.70	0	104.70
Hydrogen	Compressed H_2 from central reforming of NG	142.20	0	142.20
	Liquid H_2 from central reforming of NG	133.00	0	133.00
	Compressed H_2 from on-site reforming of NG	98.30	0	98.30
	SB 1505 Scenario; Compressed H_2 from on-site reforming with renewable feedstocks	76.10	0	76.10

Source: CARB 2009.

NESCCAF recommends that the northeast states rely on the same concept of default values that CARB has established. The specific values will differ from CARB's given different transport distances for fuels, different feedstocks, and other factors that impact lifecycle fuel emission in the Northeast.

4.2.2. Determining Compliance

According to CARB's most recent LCFS documents, California will measure fuel carbon intensity in grams of CO_2-equivalent emissions per megajoule of energy (gCO_2e/MJ). As part of its LCFS scenario analysis, NESCCAF commissioned the development of an interface tool for the GREET model; we refer to this tool as the Northeast Low Carbon Fuel GREET Interface Tool or "NE-LCFS GREET Interface Tool."

The NE-LCFS GREET Interface Tool enables a user (whether an obligated party, regulated entity, or other stakeholder) to determine the carbon intensity for a given fuel pathway based on specified or default values for key parameters. Because it directly calls upon the GREET model to generate its results, it ensures a consistent methodological approach with other programs that rely on GREET and can be updated to reference future versions of GREET as they are released. While there are some limitations to the use of the current version of GREET for compliance purposes (see Appendix B for a detailed discussion of this issue), GREET remains the most up-to-date and widely used tool for analyzing lifecycle fuel emissions at this time. A detailed description of the NE-LCFS GREET Interface Tool is also presented in Appendix B.

California is proposing to require regulated entities to submit written reports on the number of gallons and MJ equivalent of fuel sold and the carbon intensity of the fuel sold. A weighted average of the carbon intensities of all fuel sold or fuel sold plus credits purchased would need to be calculated and reported by the regulated entity. In person audits of supporting documentation could be required by the states - in addition to review of paper records - for compliance with the LCFS. A similar mechanism could be required in the Northeast.

4.3. Potential Fuels for Inclusion in a Northeast LCFS

4.3.1. Background

As discussed in the introduction to this report, two other fuel programs with direct relevance to the potential implementation of an LCFS in the Northeast and Mid-Atlantic are in development at this time. These are the federal Renewable Fuel Standard and the California LCFS. Both of these programs will regulate transportation fuel. Transportation fuel, as it pertains to the RFS, is defined in EISA as "fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels)"—thus the primary focus of this program is on gasoline and diesel fuel. In addition, EPA has discretionary rulemaking authority to expand the credit and trading aspects of the RFS program to recognize carbon intensity reductions in home heating oil and jet fuel. CARB is proposing to regulate transportation fuels, including fuel used in motor vehicle engines, nonroad vehicles, locomotives, and marine engines. CARB is not proposing to regulate jet fuel or fuel used by ocean-going vessels as part of the California LCFS. While the federal RFS program does not address the carbon intensity of petroleum based fuels (e.g., it makes no distinction between fuels produced from high carbon sources, such as tar sands, and those produced from conventional crude oil) California is proposing to establish separate baseline AFCI values for conventional petroleum fuels derived from non-conventional crude oil.[28] In neither program is No. 4 or No. 6 fuel oil being considered for regulation.

Table 4-5 compares the different types of petroleum products sold in California, the United States, and the Northeast in 2005, in terms of their percentage market share.

Table 4-5. Prime Supplier Sales Volumes of Petroleum Products (2005) Percent Allocation of Six Principal Products

Product	NESCAUM States	California	United States
Conventional and Reformulated Gasoline	56.0	63.3	60.7
No. 2 Fuel Oil	14.5	0.6	4.1
Diesel Fuel	11.5	15.8	21.6
Residual Fuel Oil	9.9	5.1	3.8
Kerosene Jet Fuel	8.1	15.2	9.8
Sum of 6 Products	100.0	100.0	100.0

Source: DOE 2006.

Table 4-5 indicates that the proportions of conventional and reformulated gasoline sold nationally and in California and the Northeast are relatively comparable. The same can be said of diesel fuel and kerosene jet fuel, though the relative volume of these products sold as a proportion of all petroleum products varies more from region to region than does gasoline. No. 2 fuel oil, used largely for boiler fuel and space heating in buildings, on the other hand, represents a much larger share of fuel sold in the Northeast compared to California and the U.S. as a whole. A total of 14.5 percent of all petroleum fuel sold in the Northeast is used for space heating. In fact, the Northeast uses a proportionately much higher volume of No. 2 and residual fuel oil generally for both electricity generation and space heating than does the rest of the country. The remainder of this chapter describes the different types of fuels shown in Table 4-5. Table 4-6 is more detailed and provides a rationale for including or excluding different categories of fuel from a Northeast LCFS program.

4.3.2. Conventional and Reformulated Gasoline

A primary objective of an LCFS is to reduce GHG emissions from the transportation sector. Approximately 27 percent of anthropogenic GHG emissions in the Northeast result from the combustion of gasoline (both conventional and reformulated gasoline) in automobiles. An additional 0.5 percent is created by the combustion of gasoline in nonroad machines such as lawn and garden equipment and various types of commercial and industrial equipment. Gasoline sales by volume make up approximately 56 percent of all petroleum sold in the Northeast region. Given the importance of reducing carbon emissions from the transportation sector and the substantial efforts being made to reduce GHG emissions from motor vehicles, reducing the carbon intensity of

[28] CARB defines non-conventional crude oil as crude oil produced by a process other than primary, secondary, or tertiary oil recovery, including crude oil produced from oil sands, heavy oil, and oil shale.

gasoline provides an additional means of reducing overall GHG emissions from the transportation sector. Consistent with the CARB and EPA programs, NESCAUM recommends that both conventional and reformulated gasoline be included in a Northeast LCFS. Gasoline used in nonroad applications should also be included in an LCFS. Because it is identical to the gasoline used by highway vehicles, it would be very difficult, as a practical matter to separate the supply of gasoline intended for nonroad applications from the supply intended for highway use.

4.3.3. Transportation Diesel Fuel and No. 2 Heating Oil

In this section, the term distillate fuel is used to refer to both diesel fuel used in transportation sources (No. 1-D) and fuel used for space heating (No. 2-D). Both of these fuels are included in the same ASTM specification (D-975)[29] and thus have similar characteristics. However, there are differences in the fuels. These differences include the cetane number (highway diesel has a higher cetane number), flash point (highway diesel has a lower flashpoint); and other requirements. The most notable difference in highway and No. 2 diesel is the allowable sulfur level for the fuels. The federal government (EPA) regulates the sulfur limit for highway diesel fuel (which is currently set at 15 parts per million) and states regulate the sulfur limit of No. 2 fuel used for space heating. The allowable level of sulfur in No. 2 fuel is approximately 2,500 parts per million in most of the Northeast.

Diesel fuel used in highway and nonroad sources

Table 4-6 shows that approximately 45 percent of the distillate fuel used in the Northeast in 2005 was for transportation (diesel fuel). The majority of diesel fuel was used in highway trucks, with nonroad sources such as construction equipment, locomotives, and marine engines accounting for approximately 14 percent of total consumption. CARB is proposing to include diesel fuel used in both highway and nonroad equipment in its LCFS program. As part of the Renewable Fuel Standard requirements of EISA, specified volumes of low carbon fuels must be introduced into the nation's diesel fuel supply for the transportation sector. Given the contribution of diesel fuel to overall transportation-related GHG emissions and given the inclusion of diesel fuel in current CARB and EPA proposals, NESCCAF recommends that any northeast state LCFS include highway and nonroad diesel fuel. This would mean that nonroad, locomotive, marine, industrial, and commercial diesel fuel uses would be covered; in fact most distillate fuel use by the industrial and commercial sectors would be covered since transportation sources are largely responsible for diesel use in these sectors. Two exceptions would be bunker fuel (fuel used in the main engines of ocean going vessels) and aviation fuel. The reason for excluding bunker fuel is that it is regulated by an international organization – the International Maritime Organization (IMO). Aviation fuel is likely excluded due to the need to maintain standardized fuel across the country for aircraft.

Table 4-6 shows the array of principal sector end uses for two types of diesel fuels (low and high sulfur) and for No. 2 fuel oil. High sulfur diesel fuel is defined as fuel with

[29] ASTM International (originally known as the American Society for Testing and Materials) is an international standards organization that develops and publishes technical standards.

sulfur content up to 3000 parts per million (ppm), while low sulfur diesel fuel is defined as fuel with sulfur content up to 500 ppm. Since the baseline data from EIA are from 2005, these figures do not reflect sales of the newer ultra low sulfur diesel fuel that is already being required for use by highway vehicles and that will be required for nonroad equipment beginning in 2010.

Table 4-6. NESCAUM Region Consumption of Fuels by End Use (2005) (Millions of Gallons)

Sector End Use	No. 2 Fuel Oil	Low Sulfur Diesel Fuel	High Sulfur Diesel Fuel	Residual Fuel Oil	Gasoline
Highway	0	3166.0	-	0	16,494
Nonroad	0	-	172.7	0	-
Locomotive	0	0	150.9	0	-
Marine	0	0	133.0	1015.0	-
Home Heating	3515.7	0	0	0	-
Farm	13.5	-	52.6	0	-
Electric Power	77.2	0	0	2452.9	-
Industrial	100.0	16.8	12.8	338.1	239
Commercial	960.1	105.9	36.7	653.4	25
Total Usage	4666.5	3288.7	558.7	4459.4	16,758

Source: DOE 2005.

Table 4-6 also shows the amount of residual fuel which is used in marine vessels (bunker fuel) and for electric power generation. Gasoline is also shown for reference.

No. 2 fuel oil used in space heating applications

As indicated in Table 4-6, the use of No. 2 fuel oil for space heating in homes and in some commercial and industrial buildings represents 55 percent of total distillate fuel use in the Northeast (4.6 billion gallons per year)—as already noted, this exceeds the amount of distillate fuel used for highway transportation (3.2 billion gallons per year). In contrast, California's use of No. 2 distillate fuel oil in thermal applications (0.02 billion gallons per year) represents an extremely small fraction of its total distillate use. Transportation uses account for 69 percent (3.0 billion gallons per year) of distillate fuel use in California. In California and other regions of the country distillate fuel is not widely used for residential space heating; California is also not proposing to regulate No. 2 fuel oil as part of its LCFS.

There are a number of reasons why the northeast states might consider including No. 2 fuel oil in an LCFS. First, the region has a unique opportunity to substitute regionally available low carbon fuels – such as woody biomass and electricity – for No. 2 fuel oil in home heating applications. Other substitutes for No. 2 fuel oil could be used to lower the average carbon intensity of fuels used for space heating, such as heat pumps, natural gas, and advanced biofuels, even though these might not be produced in the region. Further, the replacement of inefficient oil burning furnaces with modern, higher efficiency wood burning furnaces, such as pellet stoves, would reduce carbon emissions in the region. From an economic standpoint, the use of available woody biomass feedstocks would assist the contracting northeast paper industry and could help alleviate the cost burden on low-income households when heating oil prices rise. The use of woody biomass and electricity as substitutes, combined with increased natural gas use for space heating, provides near-term low carbon fuel options for the Northeast.

Furthermore, some low carbon fuel feedstocks are better suited for use in furnaces than they are for use in the internal combustion engines used to power trucks, buses, and nonroad equipment. For example, woody biomass can be used directly in thermal applications (assuming conversion from oil burning furnaces to wood or pellet stoves). Biodiesel can also be used more easily in oil burning furnaces than in highway diesel engines. This is because the performance of highway diesel engines is more susceptible to adverse effects from variations in fuel quality, compared to furnaces.

Heating oil is refined at and imported to the same facilities that refine and import gasoline and highway and nonroad diesel and both fuels are typically sold at the same retail outlets. Maintaining the same requirements for diesel fuel and home heating oil has long been a goal of fuel providers and regulators in the Northeast. Fuel distributors maintain that achieving parity between highway and nonroad fuel in terms of fuel quality and specifications is critical because handling different grades and sulfur levels requires extra tanks and otherwise increases the complexity of the distribution system.

Finally, because heating and transportation fuels share the same supply network, it would be possible for refiners to direct high-carbon distillate fuels—such as distillate produced from tar sands-derived bitumen—into the heating oil market if the carbon intensity of heating oil is not regulated. Fuel derived from tar sands currently makes up approximately 0.5 percent of the Northeast's distillate fuel supply. In the long term, the use of tar sands-derived crude will depend on numerous factors affecting the western Canadian oil industry.[30] If a larger fraction of No. 2 fuel oil used for thermal heating were to be comprised largely of tar sands-derived fuel, then the average carbon intensity of the region's fuel oil supply could rise significantly. Thus, it may make sense for the northeast states to regulate the carbon intensity of No. 2 fuel oil along with transportation distillate over the long term.

If states choose to include heating fuel within the LCFS, they might include the entire home heating sector or limit the program to No. 2 oil. Another key decision is whether to allow "switching" where an end user would replace an existing heater with an alternative technology.[31] Finally, states can choose whether to allow credits from heating

[30] Further expansion of production of crude derived from tar sands will largely depend on the market price of a barrel of oil. When prices were higher in 2008 ($140+ per barrel), expansion of production appeared viable (Whitten, 2008). With prices falling below $50 per barrel later in 2008, prospects became considerably less viable. The industry needs a minimum sustained price in the $85 to $100 per barrel range in order to support expansion (Patel, 2008).

[31] In theory, there are four possible ways to reduce the CI for a given fuel type: 1) reduce the GHG emissions associated with upstream processing for an existing fuel; 2) blend with a low-GHG fuel that is

fuels to count toward compliance with the transportation diesel carbon intensity (CI) reduction requirements.

Including a comprehensive, sector-wide heating component in the LCFS could provide significant GHG reductions while encouraging development of regional low carbon feedstocks. However, it would be substantially more complicated to design and implement compared to a transportation-only program. On the other hand, if the LCFS includes highway diesel but excludes No. 2 heating oil, "leakage" of high-carbon fuels into the heating sector could negate any benefits achieved from transportation fuels.

- Sector-wide vs. distillate-only

  A sector-wide standard would maximize the opportunity for GHG reductions, particularly since business-as-usual increases in CI are plausible not only for No. 2 oil but also for propane and kerosene, each of which could be produced from tar sand feedstocks. There would also be an increased CI for natural gas, as future supply shifts more heavily to imported LNG. However, including the entire heating sector would substantially increase the number of regulated entities from those covered under a transportation-only LCFS. In addition, it could require separate baseline CI for each major fuel category, further complicating program design and implementation.

- Switching

  Switching would allow regulated entities maximum flexibility in choosing a compliance strategy, and could enable incentives for regional biomass conversion. However, it would complicate program administration in several ways: First, switching would require tracking and enforcement at the household level in order to verify that a low carbon fuel actually displaces a high-carbon fuel.[32] Second, the efficiencies of competing technologies should arguably be accounted for in CI calculations, which would require additional compliance and enforcement efforts.[33] Finally, if the heating component of the program were limited to No. 2 fuel as recommended above, the inclusion of a switching option could be seen as unfair, as competing fuels (e.g., natural gas) might be eligible for LCFS credit but would not be penalized if their CI were to increase.

  Note that states could opt for a compromise approach, allowing switching only to selected fuels, for example from No. 2 fuel oil to wood pellets.

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compatible with the existing end-use technology; 3) switch the end-use technology to accommodate an alternative fuel; and 4) improve the efficiency of the end-use technology.

[32] Note that for transportation, the two fuel categories (gasoline and diesel) serve distinct market segments and together represent approximately 100 percent of baseline energy demand, so any alternative must by definition displace one or the other. Thus we can assume, for example, that any biodiesel sold at the wholesale level is bound to displace diesel fuel. Conversely for home heating, we can't know if, for example, wood pellets sold by a wholesaler are ultimately going to an existing wood user or will displace No. 2 oil, natural gas, or some other fuel, unless we track each fuel type to the point of end use.

[33] For example, should boiler modernization be allowed to generate credit even if no fuel switch occurs? If so, should we consider building efficiency measures such as attic insulation or replacement windows?

- Interaction with Diesel CI

  States could set a single baseline CI that includes both distillate fuel categories (transportation diesel and No. 2 heating oil) or they could set a distinct baseline for each category. A single baseline would allow maximum compliance flexibility and might be simpler to administer.[34] On the other hand, separate baselines would enable states more control in setting the stringency for each fuel type. For example, states could choose a lower reduction target, or even a simple not-to-exceed limit for heating oil, while setting a more aggressive target for the transportation sector.[35]

Residual fuel

Approximately 14 percent of all liquid fuel used in the Northeast is residual fuel (see Table 4-6). Of this fraction, more than half (55 percent) of residual fuel is used for electricity generation and 22 percent is used for commercial and industrial heating. Another 23 percent is used to fuel large ocean-going vessels. On a per capita basis, residual fuel consumption in the Northeast (at 105 gallons per person per year in 2005) is much greater than in California (39 gallons per person per year) or in the U.S. as a whole (35 gallons per person per year). This is largely because the Northeast is the only region of the U.S. that uses significant quantities of residual fuel for electricity generation. GHG emissions from the use of residual fuel for electricity generation will be subject to other policies and programs targeted to the electricity sector, including the Northeast Regional Greenhouse Gas Initiative and state-imposed renewable portfolio standards. These programs are designed to reduce overall electric-sector GHG emissions in the Northeast and increase the share of electricity produced from low carbon renewable resources instead of conventional fossil fuels, like residual oil.

The remainder of the residual fuel used in the northeast states (commercial and industrial heating applications and bunker fuel for ocean-going vessels) would remain unregulated and could remain a source of significant and possibly growing GHG emissions. However, NESCCAF does not recommend including residual fuel in a first generation LCFS for two reasons: first, it is difficult to track residual fuel and second, states have limited authority to regulate ocean-going vessels. Regulators should, however, consider including residual fuels at a later date, after an LCFS program is successfully established and initial implementation issues have been resolved. If the residual fuel market in the Northeast remains unregulated indefinitely while a carbon standard is imposed on other types of fuels, it could increasingly become a "dumping ground" for the region's high carbon fuels.

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[34] To the extent that No. 2 oil is supplied by parties that would already be regulated entities under the transportation LCFS, this might be the simplest and most effective approach, as it would simply require already-regulated entities to control CI across their entire product line as opposed to just a subset. If significant volumes of No. 2 oil are sold by parties that would not otherwise be regulated for carbon intensity (e.g., if a wholesale terminal deals exclusively in heating oil and carries no diesel), the single-baseline approach might be less compelling from the standpoint of administrative complexity.

[35] Note that one option is not inherently more stringent than another, as states can opt for more or less stringent targets in either case.

Different fuel characteristics provide further grounds for excluding residual fuel from a first generation LCFS. Residual fuel, which is made up of the fraction of crude oil that remains after the lighter, more valuable fractions have been distilled off, has a much higher viscosity than distillate oil. In fact, it is so viscous that it has to be heated in order to be used. Due to its high viscosity and high sulfur content, residual fuel also requires special processes for storing and pumping; at low temperatures it can cause damage to fuel lines, furnaces, and related equipment that were designed with lighter fuels in mind. Residual fuel is usually transported by barge and tanker truck, unlike distillate fuel which is transported mainly by pipeline.

In sum, NESCCAF recommends that gasoline and diesel used in highway and nonroad engines and machines—including marine engines and locomotives—be included in a Northeast LCFS. For the reasons discussed above, we recommend that residual fuel not be initially included in a Northeast LCFS.

4.4. Determining Baseline Fuel Characteristics

Making a determination about baseline fuel characteristics is an important step in the implementation of an LCFS. First, by specifying baseline fuel characteristics, regulators will set the market for future carbon intensity reductions in northeastern fuel. The composition of fuel sold in the Northeast has changed significantly over the past five years in a number of ways, including with respect to ethanol content and fuel sulfur levels. Importantly, the widespread phase-out of methyl *tertiary*-butyl ether (M*t*BE) between 2000 and 2006 led to the introduction of gasoline with 10 percent ethanol by volume. M*t*BE has different life-cycle carbon characteristics than ethanol. Additional issues to be considered include how many baseline fuels there should be and how they should be defined. Finally, the federal RFS requires the introduction of 36 billion gallons of renewable fuel nationwide by 2022, 15 billion gallons of which can be corn ethanol. Selecting a baseline fuel is an important issue in how the LCFS meshes with this federal regulation.

As with other issues related to program structure, the northeast states can look to EPA and CARB proposals for handling baseline issues in the context of the federal RFS and California LCFS. This section discusses considerations relevant for defining baseline fuel characteristics for a Northeast LCFS.

4.4.1. Number of baseline fuels

CARB has proposed to establish separate baselines for gasoline and diesel. The reason these two separate baselines are being considered is because diesel fuel and gasoline have different carbon intensities on a per energy unit basis. CARB has considered creating one baseline that combines the characteristics of gasoline and diesel fuel. However, this approach would have had the effect of providing an incentive for fuel providers to increase sales of diesel fuel relative to gasoline, since gasoline has a higher AFCI than diesel. Thus, a fuel provider could achieve average carbon intensity reductions simply by switching more production to diesel fuel. NESCCAF recommends that the Northeast states likewise establish separate baselines for diesel and gasoline.

4.4.2. Gasoline

Properties of Baseline Gasoline

A number of assumptions about baseline gasoline fuel properties were made in the discussion of possible compliance scenarios in Chapter 3. The basis for these assumptions and potential modifications are discussed below.

Ethanol Content of Baseline Gasoline

NESCCAF's scenario analysis assumed that RFG in the region contained no ethanol – consistent with the fuel used in the region prior to 2005. While this assumption was made for the scenario analysis, this baseline does not need to be selected for a regulatory program. Table 4-7 shows that by 2006 nearly all of the M*t*BE in reformulated gasoline had been replaced with 10 percent ethanol by volume. Approximately 60 percent of gasoline sold in the Northeast is RFG, thus the average ethanol content of all gasoline (conventional and reformulated) sold in the region in 2006 was 6 percent.

Table 4-7. Volumes of Oxygenates Added to Reformulated Gasoline in the NESCAUM Region

(Millions of Gallons)

State	2003		2004		2005		2006	
	M*t*BE	**Et-OH**	**M*t*BE**	**Et-OH**	**M*t*BE**	**Et-OH**	**M*t*BE**	**Et-OH**
CT	146.0	21	0.9	155	0.6	162	0.3	157
ME	0	0	0	0	0	0	0	0
MA	293.4	1	324.5	8	254.1	10	1.1	20
NH	57.5	0	57.2	0	53.0	0	0.1	0
NJ	483.8	1	501.5	6	481.7	7	0.9	15
NY	325.5	23	0.6	295	1.6	328	0.6	714
RI	47.9	1	56.5	8	49.7	10	0.2	20
VT	0	0	0	0	0	0	0	0
Total	**1354.1**	**47**	**941.2**	**472**	**840.7**	**517**	**3.2**	**926**

Sources: DOE 2007, EPA 2008.

Choosing an earlier year as a baseline year for the LCFS means that only a small amount of ethanol is included in the baseline average fuel since M*t*BE was still in use in much of the Northeast prior to 2006. In fact, six of the region's eight states still were allowing the use of M*t*BE in 2005; thus a baseline fuel carbon intensity calculated from 2005 fuel data will not account for the broad-based introduction of ethanol after 2005.

Federal RFS requirements, which require that 12 billion gallons of ethanol be introduced into the U.S. gasoline supply by 2010, will likely mean that ethanol will be present in even larger quantities in future years. In that case, the use of 2005 as the baseline year will result in further undercounting or over-counting of baseline carbon intensity, depending on the carbon intensity assigned to corn-based ethanol (if ethanol is assumed to have the same carbon intensity as gasoline, of course, the choice of baseline year has much less effect on the calculation). As discussed in Chapter 3, at the moment there is much discussion and substantial uncertainty about the carbon intensity of corn ethanol, particularly with respect to accounting for upstream fuel-cycle impacts and indirect effects on land use. CARB established the baseline year for the California LCFS at 2010. The northeast states will need to make a determination about the inclusion of ethanol in the baseline fuel prior to selecting a baseline fuel year.

Assuming fuel characteristics from 2005, the resulting baseline fuel AFCI is 96.7. Choosing a baseline gasoline that includes 10 percent ethanol by volume (which occurred after the phase out of M*t*BE) increases the baseline fuel AFCI because of the higher carbon intensity of ethanol fuel.

In the NESCCAF scenario analysis presented in Chapter 3, the baseline AFCI for gasoline is slightly different from the proposed CARB baseline AFCI, not only because of differing ethanol content of the two types of gasoline, but also because the carbon intensity of Northeast RBOB is slightly higher than the equivalent fuel in California (CARBOB). The NESCCAF carbon intensity values used in the analysis account for differences in transport and refining processes for the fuel. The northeast states could choose to use the Northeast-specific carbon intensity value developed by Lifecycle Associates, or the states could choose to use the same value that CARB is proposing to use. For the purpose of carbon accounting, it would be more accurate to use the Northeast-specific value for the baseline gasoline.

Sulfur content of baseline gasoline fuel

Fuel sulfur content can affect lifecycle GHG emissions because the additional refining needed to lower sulfur levels increases the amount of fuel processing needed, which in turn generates higher GHG emissions. For purposes of this analysis, NESCCAF assumed baseline gasoline sulfur content of 30 ppm, consistent with federal requirements. In addition, choosing an average value for refining efficiency (discussed below) means that differences in sulfur are not accounted for under the LCFS.

Refining Efficiency

Calculations of lifecycle carbon emissions for conventional fuels include an upstream component plus direct carbon emissions from combustion of the fuel. Upstream emissions include emissions associated with extraction, refining, and transport of feedstocks. The GREET model attributes roughly 20 percent of carbon emissions associated with the use of gasoline and diesel to upstream processes while 80 percent of lifecycle carbon emissions are estimated to come from the actual combustion of the fuel. It may be possible to reduce upstream emissions by making the petroleum refining process more efficient. This raises the question of whether changes in refinery efficiency should be taken into account when calculating lifecycle carbon intensity for purposes of implementing an LCFS.

CARB has proposed to assign a default value for refining efficiency in the implementation of its program. This makes sense for a few reasons related to how fuels are purchased and distributed. In addition, upstream emissions are likely to be covered as part of a program to reduce GHG emissions from major stationary sources, including refineries and industrial facilities.

However, taking this approach will mean that any carbon reductions resulting from upstream improvements in refining efficiency would not be counted in an LCFS. A more detailed discussion of refining efficiency and other assumptions that are central to the development of fuel carbon intensity factors is presented in Appendix B. NESCCAF recommends that states in the Northeast follow CARB's approach and assume a default value for refining efficiency for purposes of LCFS implementation. We believe this approach is more practical and that the regulation of refinery emissions is better suited to a regulatory program tailored to stationary sources.

4.4.3. Diesel

Four issues related to calculating the baseline lifecycle carbon intensity of diesel fuel are discussed in this section: (1) whether to establish separate baselines for diesel and gasoline; (2) whether and how to credit diesel vehicle efficiency; (3) assumptions about fleet type as opposed to fuel type; and (4) assumptions about the penetration of alternative fuels in the baseline diesel calculation.

Separate diesel baseline

CARB has proposed establishing two baselines: one for gasoline and one for diesel. There are a number of reasons to take this approach. First, two baselines would create incentives for the development of low carbon fuels suitable for both diesel and gasoline engines. In addition, air quality and public health officials are concerned about the potential for an increase in the number of light-duty diesel vehicles because of health data showing that particulate matter (PM) from diesel vehicles is a carcinogen and can result in significant non-cancer health effects. A policy designed to reduce GHG emissions that had the effect of simultaneously increasing diesel PM emissions would therefore be considered problematic; rather, fuel policies should provide both public health and environmental benefits. Finally, there is significant uncertainty among experts about how potent a greenhouse forcing agent black carbon is. Given this uncertainty, creating an incentive for the introduction of diesel vehicles at this time may not be an appropriate strategy.

As already noted, the use of a single baseline that combines diesel and gasoline characteristics creates an incentive for fuel providers to shift production to diesel fuel, which has a lower lifecycle carbon intensity. The use of separate baselines avoids this problem and is therefore the approach that California appears to be taking.

The carbon intensity of low sulfur diesel (500 ppm cap) is different from the carbon intensity for ultra low sulfur diesel (15 ppm cap). This is due to different energy requirements for refining the two different fuels. CARB has proposed to designate ultra low sulfur diesel fuel as the baseline diesel fuel. NESCCAF recommends that the northeast states also use ultra low sulfur diesel fuel as the baseline diesel fuel, given that this fuel is now required in highway sources and will soon be required in nonroad diesel engines as well.

Alternative Fuel Assumptions in the Diesel Baseline

NESCCAF did not estimate the amount of alternative fuels used in 2005 as part of its baseline diesel analysis. Alternatives to conventional diesel fuel include compressed natural gas (CNG), liquid natural gas (LNG), and others. Excluding alternative fuels from the baseline will raise the diesel baseline AFCI slightly, since natural gas and other alternative fuels have a lower carbon intensity than diesel fuel. However, given the fact that most fuel providers sell only diesel, and not both diesel and alternative fuels, NESCCAF opted to exclude the alternative fuels. Including them would have penalized providers of diesel fuel in the sense that they would have a lower baseline had alternative fuels been included. In any case, the amount of alternative fuels currently used on an annual basis is small in the Northeast.

Sulfur Content of Baseline Diesel Fuel

NESCCAF assumed a sulfur content of 15 ppm for baseline on-highway diesel fuel and 500 ppm for nonroad diesel fuel.[36] The allowed sulfur content of heating oil in the region ranges between 2,000 and 20,000 ppm. The majority of the heating oil used in the region is regulated at approximately 2,500 ppm. An agreement reached in the Northeast on regulating No. 2 fuel oil sulfur content states that No. 2 fuel oil sulfur content must be no higher than 500 ppm by 2018.[37]

4.4.4. Increases in Carbon Intensity of Baseline Fuels Due to Tar Sands and Other Non-Conventional Sources

Presently, fuels derived from Canadian tar sands play a relatively minor role in supplying the northeastern market. Finished petroleum products, imported from Canada into the Northeast, are largely if not exclusively supplied by refiners in the Atlantic Canadian Provinces and derived from conventional sources of crude oil. Overall, Canadian refiners supply approximately 4 percent of Northeast demand for gasoline and light distillates.

A single northeast refiner processes western Canadian crude oil; United Refining in Warren, Pennsylvania. United's refining capacity represents about 4 percent of the total refining capacity in the region. In 2006, about half of United's crude slate was heavy crude oil. Of this amount, approximately 60 percent of the heavy crude was derived from conventional sources and the other 40 percent from Canadian tar sands. Overall, United supplies approximately 1 percent of Northeast's demand for gasoline and light distillates, primarily serving retail markets in western Pennsylvania and western New York.

United is adding a delayed coker to its refining operations in order to process a higher percentage of heavy crude oil. Its near term goal is to process approximately 80 percent heavy crude, both from conventional and tar sands sources. In the longer term, the plan is to process heavy crude as the exclusive feedstock. Thus, in the long term, the market share of finished products in our region derived from heavy Canadian crude and processed in the region will double, from the current half-percent to about 1 percent (i.e., United's total market share). The split between conventional heavy crude and tar sands

[36] Current federal regulations limit highway diesel sulfur to 15 ppm phasing in between 2007 and 2010 (EPA, 2001). Prior to 2007, the limit was 500 ppm. Federal regulations limit nonroad diesel fuel sulfur content to 500 ppm by 2007 and the allowable sulfur content drops to 15 ppm in 2010 (EPA, 2004). For locomotive and marine engines, fuel sulfur content is required to be 15 ppm beginning in 2012 (EPA, 2007).

[37] The northeastern states have agreed to require reductions in the sulfur content of No. 2 fuel oil.

derived crude will depend on numerous factors affecting the western Canadian oil industry.

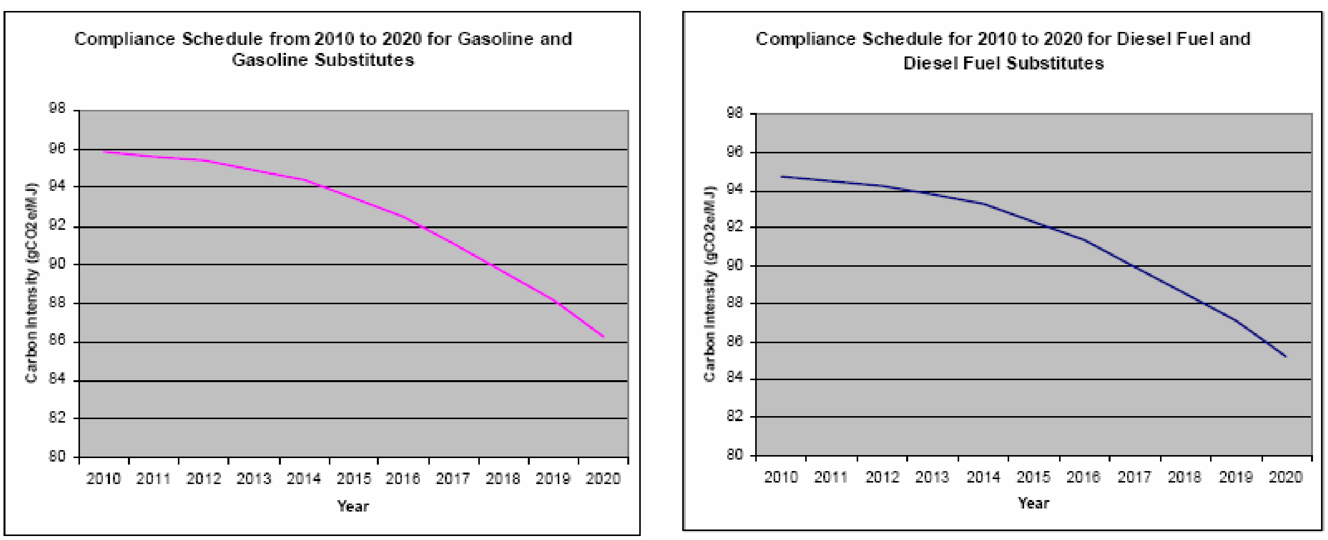
CARB is proposing to establish a separate carbon intensity value for unconventional fuels. This will allow for more accurate carbon accounting of the baseline fuel. A Northeast LCFS should also establish a separate carbon intensity number for unconventional fuels.

4.4.5. Carbon Intensity Values for Northeast Fuels

The NESCCAF scenario analysis presented in Chapter 3, and described in Appendix B, states that Northeast-specific carbon intensity values were developed by Lifecycle Associates. This analysis took into account the Northeast's fuel feedstocks, transport distances, modes of transport, Northeast-specific fuels, such as woody biomass, and refining process. Some of the carbon intensity values used in the scenario analysis differ from the values being used by California and some are the same. The Northeast-specific values could be used as part of the Northeast LCFS, or the states could choose to use the values California has developed. The decision will rest, in part, on ease of implementation of the program.

4.5. Timeframe for introduction of the Low Carbon Fuel Standard

California has proposed to design its LCFS to achieve a 10 percent reduction in the average carbon intensity of transportation fuel by 2020. CARB's March 2009 LCFS ISOR provides the following proposed compliance schedule.



Source: CARB 2009.

Figure 4-2. CARB's Proposed LCFS Compliance Schedule

Figure 4-2 shows CARB's proposed phase-in schedule for an LCFS program. The proposed schedule would require modest reductions in transportation fuel carbon intensities between 2010 and 2014 (1.3 percent reduction for both gasoline and diesel). Larger reductions are required in 2015 to 2020. This approach presumably allows time for the development of advanced biofuels. This approach also delays much of the carbon intensity reduction requirement until the later years of program implementation. The advantage of this approach is that regulated entities will have time in the early years of the program to develop strategies to meet the standard. The drawback, however, is that this approach could diminish incentives for firms to act early to accelerate the development and introduction of new low carbon fuels. The phase-in schedule ultimately chosen for California's program will reflect expert opinion on the likely timeframe for development of advanced biofuels and low carbon fuels.

For the purposes of the analysis described in Chapter 3 of this report, NESCCAF assumed a linear phase-in trajectory between 2010 and 2020 designed to achieve the same 10 percent overall carbon intensity reduction in the same timeframe as California has proposed. If possible, the Northeast and Mid-Atlantic should choose the same phase-in schedules state to state (within our two regions), given the fungible nature of the transportation fuel market.

4.6. Incorporating Non-Liquid Fuels into an LCFS

Some of the fuels that offer the greatest, near term potential to reduce GHG emissions from the transportation and thermal heating sectors are not liquid fuels and cannot be blended with conventional fuels. These alternatives are: electricity, natural gas, and woody biomass. Electricity could be used to power plug-in hybrid and battery electric vehicles, while woody biomass and natural gas could be used directly as a substitute for No. 2 fuel oil in heating applications. This section discusses mechanisms to incorporate these important fuels into a Northeast LCFS.

4.6.1. Electricity

Electricity used to power plug-in hybrid and battery electric vehicles is an important potential source of low carbon fuel in the Northeast. The generating technologies used to produce electricity in the Northeast emit relatively low CO_2 on a gram/MJ basis as compared to other regions of the U.S. or the U.S as a whole. This is because the Northeast's electricity supply mix includes a relatively high proportion of nuclear, natural gas, and hydro power. As a result, the use of electric plug-in hybrids and battery electric vehicles has the potential to reduce carbon emissions from vehicles significantly in our region. In addition, the RPS and RGGI programs, when implemented, will further reduce the carbon intensity of the region's electricity.

Since electricity is not a liquid fuel and as such cannot be blended with conventional gasoline or diesel, several significant challenges exist to incorporating electricity into an LCFS. These include the need to establish a mechanism to measure the use of electricity in vehicles; a means of providing credits to utilities that generate electricity for use in plug-in hybrid and battery electric vehicles; and an agency or organization to coordinate the sale and purchase of electricity credits. A method for estimating the amount of electricity use in battery electric or plug-in hybrid vehicles will need to be developed. In the near term, electricity use could be estimated based on electric vehicle and plug-in hybrid vehicles registered in the state, combined with an average assumed VMT and electricity use per VMT. While this would only provide an approximate estimation of the electricity used - due to the variability in vehicle miles traveled, recharging behavior, driving behavior, and other factors - it would allow for a credit trading program to be started. In later years, more advanced measurements of vehicle electricity use through the vehicle on-board diagnostic (OBD) systems, smart metering, and other approaches could be used to improve electricity use estimation in motor vehicles.

There are a few models that could be used to develop a northeast electricity credit trading mechanism. States in the region are currently evaluating other regulatory programs that have established trading programs as potential models for the LCFS. This process is ongoing. As part of a credit trading program, credits will need to be quantified and approved prior to being traded. A number of different entities, including state agencies and private companies, could participate in aspects of such a system.

4.7. Chapter Summary

California's LCFS regulatory documents provide a potential template for a northeast state LCFS program structure. Recommendations from NESCCAF's evaluation of the California program documents and the fuel distribution system in the Northeast include:

- The northeast states should include gasoline fuel used in highway and nonroad sources in the LCFS. In addition, diesel fuel used in highway and nonroad applications should be included, with the exception of ocean going vessel fuel (bunker) for which standards are set by an international organization (the International Maritime Organization) and aviation fuel.
- Given the large volumes of No. 2 fuel oil consumed in the Northeast for thermal applications in the residential, commercial, and industrial sectors, an evaluation should be conducted regarding inclusion of No. 2 fuel in a Northeast LCFS.
- There is substantial potential for non-liquid fuels to partially replace the traditional, petroleum-based fuels as one of the key strategies for reducing average carbon intensity of the fuel supply. In the transportation sector, vehicles may be powered by electricity in hybrid or fully electric applications. Natural gas may also have an increased role in powering vehicles. An LCFS program must include means to encourage penetration of these alternative energy sources into sectors where their potential has yet to be fully exploited.
- One of the initial steps in setting goals for reduction in fuel carbon intensity is to establish a baseline condition. The northeast states need to evaluate the inclusion of ethanol in the baseline gasoline fuel or excluding ethanol for the baseline gasoline.

- The northeast states should evaluate whether or not to include the Renewable Fuel Standard in a business as usual case of the LCFS and specifically whether or not to require GHG reductions above and beyond what the RFS will deliver in the Northeast. Requiring additional GHG reductions will get us closer to our GHG reduction goals, but will greatly increase the volumes of fuel needed to comply with the LCFS.
- The northeast and mid-Atlantic states need to determine on a state by state basis which entities should be regulated in order to ensure inclusion of imported finished and unfinished fuels into the region in an LCFS program.
- Given that the Northeast's fuel distribution system is highly integrated, elements of a low carbon fuel standard in our region should be the same from state to state – such as stringency of the standard.
- The northeast states should commit to utilizing the same lifecycle GHG calculation method as California and EPA to maintain consistency for regulated entities.

5. ANALYSIS OF REGIONAL SUPPLY OF LOW CARBON FUELS

This chapter presents results from a NESCCAF analysis of the supply of low carbon fuel that could be produced from resources located in the Northeast. Specifically, NESCCAF evaluated the potential supply of feedstocks from the region, as well as the status of the technologies available to convert these feedstocks into low carbon fuels. Electricity can also be considered a low carbon fuel, because the technologies needed to use electricity in vehicles (i.e., plug-in hybrid vehicles) are currently commercially available. So, electricity is also evaluated in this chapter.

This chapter is organized as follows: Section 5.1 provides an overview of key considerations and assumptions. Section 5.2 summarizes NESCCAF's findings on the availability of woody, waste-based, and agricultural biomass feedstocks in the eight NESCAUM states and Pennsylvania.[38] Section 5.3 evaluates the technologies available for converting biofeedstocks into low carbon fuels in the near-term and the long-term. Section 5.4 explores the use of electricity as a low carbon transportation fuel for electric drive vehicles and their impacts on grid capacity and infrastructure needs.

5.1. Overview of Analysis

Securing an adequate supply of low carbon fuels is a critical component of effective implementation of an LCFS. Recent scientific research on the potential lifecycle GHG emissions associated with forest and agricultural biofuel feedstocks finds that lifecycle GHG emissions for these fuels may be significant when additional lands are cleared. This is usually in response to growing global demand for food and fuel. Thus, to achieve the GHG goals of a low carbon fuel standard, it is important to promote the use of low carbon fuels that are less likely to induce substantial land use change (Searchinger *et al.* 2008).

While combustion of woody biomass does generate emissions of carbon dioxide, the carbon emissions generated during combustion are simply a release of the carbon originally stored by the tree or plant during the process of photosynthesis. Wood is a store of carbon, often referred to as a "carbon sink." For biomass combustion to consistently achieve low levels of net CO_2 emissions, forest ecosystems should be managed and harvested such manners that sustain the store of terrestrial carbon over time. Management practices which remove more carbon than is accumulated by the ecosystem will eventually deplete the carbon stock, diminishing or possibly eliminating climate benefits on a long-term basis. In some forest and agricultural ecosystems, the store of carbon may actually be enhanced through careful harvest practices. In other ecosystems, it may be preferable from both a carbon sequestration standpoint and ecological health standpoint to reduce or eliminate harvests, or change agricultural practices (i.e., intensive fertilizer use). Producing woody and agricultural fuels that provide climate benefits will require effective forest management and land use policies ensuring that biomass resources are not exploited beyond their ability to maintain or increase long-term carbon storage capacity.

[38] Maryland and Delaware are also included in the assessment of waste-based biomass and electricity.

In addition, careful measurement and monitoring of carbon stores will be required at regular intervals to ensure sustainable management.

To address the concerns about indirect land use change, this analysis focuses on the potential for producing fuels from locally sourced feedstocks which are not being used for existing markets, and waste feedstocks such as municipal solid waste. The assumption is that these feedstocks are less likely to create additional market pressures that result in greater land use change and carbon loss than do feedstocks sourced from national and international commodity markets.

Table 5-1 below provides a summary of potential quantities of low carbon fuels that could be produced, using conservative estimates of feedstock availability, from resources found in the Northeast. While these quantities are relatively modest relative to the region's overall need for fuels, locally grown feedstocks and in-region fuel production can generate substantial regional economic benefits, especially in instances where locally produced fuels displace imported fuels. It is worth noting, however, that a regional LCFS would require fuels and feedstocks produced outside the region as well as those sourced within the region.

Table 5-1. Potential Low Carbon Fuel Production from Likely Available Regional Resources, 2010 and 2020

Quantities of Low Carbon Fuel	2010	2020
Electricity (MW)	849	1,524
Thermal energy (no. of average homes heated)	400,000	1,000,000
Liquid fuels (million gallons)		
Biodiesel[39]	6.6	6.7
Cellulosic ethanol	--	440

Another key consideration in the implementation of an LCFS is the rate of technological innovation of fuels and related technologies. Concerns about environmental degradation, climate change, national security, long-term petroleum supply adequacy and price volatility are all contributing to a growing consensus that a profound transformation of current energy systems is needed. In response, a variety of federal and state government initiatives—including direct subsidies, policy incentives, and volumetric fuel mandates—have been introduced to advance new biofuel technologies and related research, development, and deployment (RD&D) efforts. Expectations are that this research will result in "advanced" or "second-generation" biofuels that have lower production energy and cost requirements than first-generation biofuels, such as corn ethanol. While there are uncertainties about the timing of advanced biofuels and related

[39] Biodiesel for home heating uses B5 (fuel blend including five percent biodiesel). Based on this analysis, the region could likely produce approximately 131 million gallons of B5 in 2010 and 134 million gallons of B5 in 2020.

technologies, experts in the cellulosic ethanol industry hope to have full-scale commercial production within five years. Similarly, General Motors and Toyota have announced plans to bring plug-in vehicles to market by 2010.

Because of the innovation underway in the biofuels and related energy industries, we examine the potential supply of low carbon fuels in two phases—those low carbon fuels that can be produced with existing technologies in the near-term, and those that may be produced with advanced technologies in the future. First, we assume that existing fuels and technologies will continue to dominate the marketplace over the next five plus years, while new fuels and technologies continue development towards commercial viability. Then, we evaluate the potential supply of low carbon fuels available by 2020, based on best available current projections of the likely characteristics of advanced biofuels and technologies. Obviously, the long-term projections are subject to a significantly higher degree of uncertainty than the near-term estimates.

Finally, we note that there are valid concerns over the potential for negative environmental tradeoffs associated with an increased production of forest and agricultural feedstocks from the region. Given the high population density in the Northeast, the region places high priority on other "ecosystem services"—aesthetics, open space, watershed protection, wildlife habitat, and recreation—provided by forests and agricultural lands. Poor land management practices have, in many cases, resulted in significant damages to forest and agricultural ecosystems and associated amenities.[40] For example, a 2007 study found that nitrogen loadings resulting from increased corn cultivation in the upper Midwest are worsening already-hypoxic conditions of the 'dead zone' in the northern Gulf of Mexico (Donner and Kucharik 2008).

As mentioned earlier, recent studies of the lifecycle GHG impacts of biofuels have raised the prospect that increased global demand for biofuels will create market effects and subsequent land use changes. In some cases these land use changes may result in releases of GHG emissions that may equal or even exceed GHG reductions associated with biofuels' displacement of fossil fuels (Searchinger *et al.* 2008). Because renewable fuel policies could cause secondary impacts in markets for agricultural and forest products potentially increasing GHG emissions, estimates of biomass in this analysis include only resources of woody, agricultural, and waste-based biomass that are in addition to biomass sold into existing markets. While this approach to estimating biomass availability does not guarantee avoidance of all market impacts, it is likely to reduce the risk of inducing them.

An original analysis of the environmental sustainability of regional forest, agricultural, and waste-based biomass resources, electricity, and low carbon fuels derived from regional feedstocks was not possible within the scope of this study. Instead, this analysis is based on relatively conservative screening-level assumptions about feedstock sustainability, technological innovation, and market transformation. The use of a conservative approach is not to suggest these estimates are appropriate levels for feedstock supply and regional fuel production in support of regional LCFS implementation. Rather, the intent is to provide policymakers and stakeholders with a

[40] During the period from 1600 to 1909, forest land area in the Northeast fell by nearly 50 percent, from 97 million to 48 million acres (Irland 1999).

first-order estimate for low carbon fuels sourced from within the region which can serve as the basis for discussion of sustainability issues.

5.2. Estimates of Regional Feedstocks for Low Carbon Fuels

5.2.1. Woody Biomass

The Northeast is one of the most densely forested regions in the United States, with over 70 percent of land covered by forest, equivalent to about 70 million acres (Irland 1999). Because of this, woody biomass is one of the region's few indigenous sources of fuel and one of its most significant renewable energy resources. This analysis considers the potential supply of woody biomass from the northeastern region[41] for potential conversion into both solid and liquid low carbon fuels, based on existing technologies and projections of future fuels and technologies.

All estimates of woody biomass supply in the Northeast are derived from data and original analysis provided by Integrated Natural Resource Solutions LLC (INRS 2008).[42] Estimates of the region's woody biomass supply rely primarily on INRS's analysis of publicly available data from a variety of sources, including the U.S. Department of Agriculture Forest Service's *Forest Inventory Analysis* and *Timber Products Output* databases, the Resource Planning Act Assessment, state- and region-specific reports on biomass generation, sawmill production, timber harvesting activity, and wood waste generation.[43]

It is important to note that woody biomass is an aggregate description that represents numerous categories of biomass types. Not all woody biomass is appropriate for every end-use or technology. Each type of biomass fuel has unique characteristics, including moisture content and Btu content (British thermal units, a measure of heat content). For example, because of relatively high soil content, forest residues are not suitable for cellulosic ethanol production but are generally appropriate for biomass combustion in electricity generation units.[44]

This analysis provides estimates of woody biomass supply by category type and associates each type with appropriate uses and technologies. Categories of woody biomass considered in this analysis include: forest residues, sawmill residues, secondary mill residues, net forest growth, and urban wood residues. Appendix D to this report contains detailed descriptions of data and methods used to generate estimates for each of these biomass categories.

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[41] States included in this analysis of woody biomass resources include the six New England states, and the mid-Atlantic states of New Jersey, New York, and Pennsylvania. Estimates of woody biomass for Maryland and Delaware were not available in time for this analysis.
[42] INRS, LLC is a forestry and natural resource consulting and research firm located in Portland, Maine. For more information, see: www.inrsllc.com.
[43] A description of underlying data and assumptions in INRS' analysis of woody biomass availability can be found in *Appendix D* to this chapter.
[44] Forest residues include the otherwise unused portion of a tree harvested for sawlogs, veneer, pulpwood, or other roundwood product after the most valuable portion of the tree, the straight, lower section, is harvested for lumber, paper or pulp markets.

Table 5-2 below describes estimated quantities of woody biomass available in the region, both in terms of "maximum" and "likely" availability.[45] This analysis assumes that only a fraction of the maximum availability of each category (from 10 percent to 40 percent) would likely be available, due to a host of environmental, social, and economic factors. On average, this analysis conservatively assumes that 15 percent of maximum biomass would be likely available for use under an LCFS. This translates into slightly over 5 million dry tons out of a maximum of nearly 33 million dry tons equivalent. The most significant category of woody biomass resources is new forest growth, which includes (but is not limited to) lower-grade wood not currently being used in markets.

Table 5-2. Total Woody Biomass Resources by Category, Maximum and Likely Availability

Region	Forest Residue	Sawmill Residues	Secondary Mill Residues	Urban Wood Residues	Net Forest Growth	Total
	Green Tons*	Green Tons*	Dry Tons	Dry Tons	Green Tons*	Dry Ton Equivalent*
Estimated Maximum Availability						
New England	7,400,000	2,990,000	140,000	1,640,000	3,870,000	9,765,600
Mid-Atlantic	4,600,000	4,390,000	330,000	4,590,000	23,640,000	23,192,800
Maximum Total	**12,000,000**	**7,380,000**	**470,000**	**6,230,000**	**27,510,000**	**32,958,400**
Estimated Likely Availability						
Availability Factor	20%	20%	40%	20%	10%	
New England	1,480,000	598,000	28,000	328,000	387,000	1,736,400
Mid-Atlantic	920,000	878,000	66,000	918,000	2,364,000	3,314,720
Likely Total	**2,400,000**	**1,476,000**	**94,000**	**1,246,000**	**2,751,000**	**5,051,120**
*For the dry ton equivalent totals, green tons have been converted to dry tons using a factor of 0.56.						

Interestingly, as shown in Table 5-3 below, the geographic distribution of available woody biomass resources is highly concentrated in two states—New York and Pennsylvania. While New England has significant quantities of woody biomass, much of these resources is already being deployed in existing markets (e.g., for sawtimber, pulp and paper). Because current market conditions limit the distances over which it is economically viable to transport woody biomass to about 50 miles, this geographic concentration could have important implications for the development of low carbon fuel production facilities and related infrastructure.

[45] Estimated quantities are quoted in either green tons or dry tons to reflect how each category of biomass is typically sold in the marketplace. For example, forest residues are sold into the market as green tons for a variety of uses, such as wood chips for electricity generation.

Table 5-3. Maximum Woody Biomass Available, by State

State	Dry Ton Equivalent
Connecticut	1,072,000
Massachusetts	1,698,000
Rhode Island	193,000
Vermont	2,488,000
Maine	2,288,000
New Hampshire	2,761,000
New York	12,561,000
New Jersey	1,980,000
Pennsylvania	11,689,000
Maximum Availability	36,730,000
Likely Availability	5+ million dry tons

Source: INRS 2008.

5.2.2. Agricultural Biomass

Land use patterns in the Northeast have shifted substantially over the last two centuries. As the Midwest opened up to agricultural production in the late 19th and early 20th centuries, agriculture in the Northeast became comparatively less competitive. Over the last century, many of the Northeast's farms were abandoned and have since reverted back to forest. Other agricultural lands have been converted into exurban and suburban development. As a result, the Northeast is no longer a major agricultural producer in comparison to the Midwest, the South, and California. However, agriculture still does play a relatively important role in the economies of some northeastern states—New York, Pennsylvania, Vermont, and Maryland in particular.[46] In addition, some northeastern states are exploring the use of agricultural residues for bioenergy products. For example, research is currently underway in New York and other states to test the viability of fast-growing energy crops (e.g., willow, hybrid poplar) on marginal pasture and croplands (Volk *et al.* 2004).

Table 5-4 below shows estimates of maximum and likely availability of agricultural biomass from energy crops in the northeastern states, based on an analysis conducted for the Northeast Biomass Research Program (Xenergy 2003).[47] This analysis assumes the likely availability of agricultural biomass for low carbon fuel production to be 50 percent of the maximum. Since the scope of agricultural lands in the northeastern states is modest relative to lands covered by forest, the likely availability of agricultural resources of 1.6 million dry tons per year is a less than one-third of the region's likely woody biomass availability.

[46] According to the US Department of Agriculture, agricultural employment and income still play a significant role in New York, Pennsylvania, Vermont, and Maryland in particular. For more information about the role of the agricultural sector in individual states, see: http://www.ers.usda.gov/StateFacts/.
[47] This analysis includes all of the New England and mid-Atlantic states.

Table 5-4. Total Agricultural Biomass Resources by Region, Maximum and Likely Availability

Maximum Availability	**Dry Tons**
New England	449,200
Mid-Atlantic	2,829,200
Total	**3,278,400**
Likely Availability	**50% of Maximum**
New England	224,600
Mid-Atlantic	1,414,600
Total	**1,639,200**

Source: Xenergy analysis (2003) for NRBP.

5.2.3. Waste-based Biomass

The Northeast is one of the most densely populated regions of the U.S., so the volumes of waste generated within a fairly limited geographic region are substantial. Municipal solid wastes (MSW) have long been an input for energy production in the region—there are currently 40 waste-to-energy facilities in the Northeast. These plants have the capacity to manage almost 43,000 tons per day of MSW and produce 1,085 MW of electricity (Integrated Waste Services Association 2007).

Because waste-based biomass does not raise the same concerns about indirect land use change caused by market-induced effects as virgin biomass feedstocks do, this analysis includes consideration of waste-based biomass as a possible feedstock for low carbon fuel production. It is important to note that the many of the northeastern states have waste reduction policies that generally aim to reduce the quantities of waste generated, and to recycle as much as possible thereafter.[48] However, this analysis assumes that some wastes will continue to be generated regardless of waste reduction policies. To determine the possible contribution of waste-based resources to the potential production of low carbon fuels, this analysis includes only that portion of the waste stream which is not a candidate for additional source reduction and/or recycling efforts.

Based on these screening assumptions, waste-based biomass considered in this analysis is defined as refuse that is organic and becomes available after primary use and all economically and environmentally beneficial options for disposal, such as reuse or recycling, have been exhausted. Using this definition, we considered the organic portion of municipal solid waste (MSW), including: yard waste, food waste, paper waste, wood from construction and demolition (C&D) debris, used cooking oils, and biosolids from wastewater treatment facilities and livestock. We analyzed the energy potential for each waste-based biomass source while considering a suite of technologies for transforming

[48] For example, Massachusetts is updating its solid waste master plan to consider options for reducing waste and increasing recycling (see: http://www.mass.gov/dep/public/hearings/smwpmtgs.htm#about.

waste-based biomass to electricity, ethanol, or other fuels for transportation and thermal uses.

Waste-based biomass is a unique source for the region because population density translates directly into waste density. The Northeast as a whole produces almost 63 million tons of MSW annually, about 16 percent of the national waste stream (Simmons *et al.* 2006). Much of this waste is already being collected and partially sorted for disposal. Because these wastes are often exported long distances by truck for disposal, local conversion to a useful energy source could significantly reduce the lifecycle greenhouse gas emissions associated with its use.[49]

Estimates of quantities of waste-based feedstocks in the region were based on a number of sources. Because most wastes are population-dependent (i.e., the magnitude of the waste stream is highly correlated with population), feedstock quantities were estimated on a per capita basis using population data from the U.S. Census Bureau's website.[50] Quantities of various categories of waste-based biomass were then extrapolated into the future using the U.S. Census Bureau's population projections for the northeastern states and per capita waste quantities (U.S. Census Bureau 2008).[51]

Table 5-5 below provides estimates of waste-based biomass by different types of resources, including MSW, waste oils, wastewater treatment facility (WWTF) solids, livestock wastes, and wastewater biogas. Municipal solid waste is the most dominant category, with likely availability of over 20 million dry tons in 2010, and 20.7 million tons in 2020.

Table 5-5. Total Waste-based Biomass Resources by Resource Type, Maximum and Likely Availability

	Units	Maximum Availability		Likely Availability	
		2010	2020	2010	2020
MSW	**Tons**	66,492,294	67,576,482	20,390,809	20,723,277
Waste Oil	**Tons**	251,000	25,100	257,000	25,700
Other Wastes (WWTF Solids)	**Tons**	10,430,126	10,590,876	5,215,063	5,295,438
Other Wastes (Livestock Waste)	**Tons**	1,450,415	1,470,707	725,208	735,354
Other Wastes (WWTF Biogas)	**Cubic feet**	55,785,179	56,565,669	27,892,590	28,282,835

[49] Appendix D to this chapter includes an example of a lifecycle analysis specific to MSW that examines the average distances waste is transported out of the northeast states, but also quantifies the carbon storage, sequestration, and avoided energy usage associated with burial in a landfill, reclamation to avoid use of virgin materials, and recovery of energy contained in the organic matter in the waste.

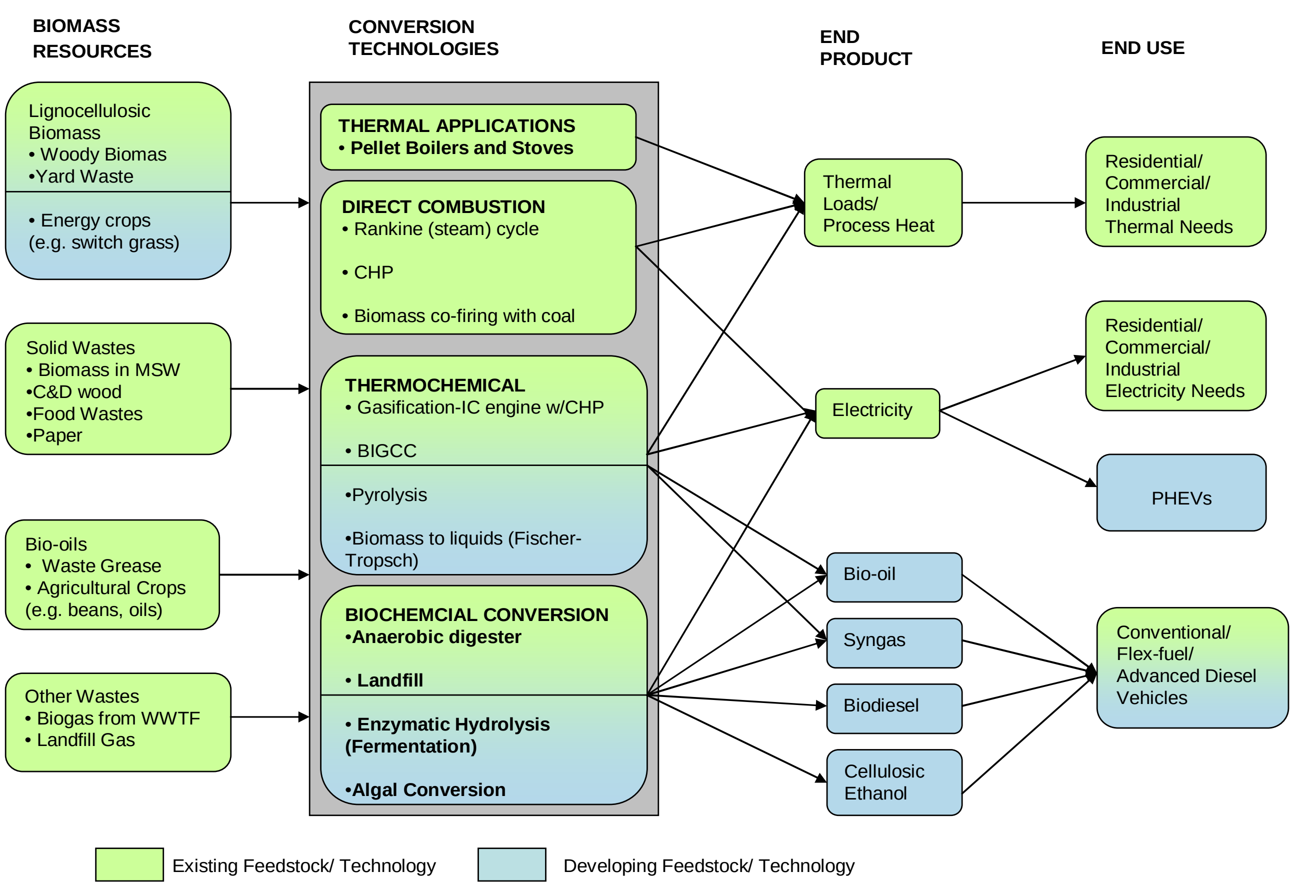
[50] Note that this methodology may be less accurate for the livestock and grease categories of biowaste.

[51] More detail on the data and methods used to generate estimates of waste-based biomass quantities can be found in Appendix D.

5.3. Biomass Technology Assessment

This analysis makes an important distinction between technologies that are currently available in the commercial marketplace for converting biomass to a low carbon fuels, such as thermal energy and electricity, and more advanced technologies that are currently under development but not yet commercially viable. We assume that in the near-term (i.e., within 5 years), technologies that are currently commercially available will dominate the market for converting biomass to low carbon fuels.

In Figure 5-1 below, pathways for numerous types of biomass resources are depicted, showing their conversion via numerous technologies into a variety of end-products. Typical conversion pathways for existing technologies are depicted in green. Over the long-term (i.e., 10 to 15 years), this analysis assumes that advanced technologies which are currently under development will be commercially viable over that timeframe, and will therefore be relatively competitive with existing technologies. Conversion pathways for these advanced technologies are shaded in blue.



Source: Adapted from Rutgers University (2007).

Figure 5-1. Existing and Advanced Biomass Conversion Technologies

5.3.1. Existing Biomass Conversion Technologies

Estimates in this analysis reflect that in 2010, the most likely technologies to be employed will be used to convert available biomass to thermal energy and/or electricity. These conversion processes involve well-proven and commercialized technologies, viable economics, a relatively well-developed supply infrastructure and – in the case of electricity – renewable energy policies that supports the deployment of these technologies.

Table 5-6 below displays each of the existing biomass conversion technologies considered in this analysis, the types of biomass resources best suited to each technology, end-products (e.g., thermal energy), size range, and technology efficiency (i.e., rate of resource use). Each of these technologies is described in greater detail below.

Table 5-6. Existing Biomass Conversion Technologies[52]

Conversion Technology	Direct Combustion for Electricity		Thermal	
	Combined Heat and Power	**Large-Scale Electricity/ Waste-to-Energy**	**Institutional Thermal**	**Residential Thermal**
Biomass Types	• Forest residues • Urban wood • Sawmill residues • Ag. residues	• Forest residues • Urban wood • Sawmill residues • Ag. residues • MSW • WW/Ag. solids	• Sawmill residues • New forest growth (roundwood)	• Sawmill residues • New forest growth (roundwood)
Products	Electricity and thermal energy (process heat)	Electricity	Thermal energy (heat)	Thermal energy (heat)
Size range	500 kW to 60 MW	5MW to 50MW	25 to 1500 horsepower	0 to 350,000 Btu thermal input
Efficiency	40 to 80 percent, depending on technology and heat captured	Roughly 30 percent, varying slightly with size, technology, and configuration	60 to 90 percent	40 to 80 percent[53]
Resource Use/Rate of Conversion	Varies, depending on technology and heat captured	13,400 green tons of woody biomass per MW (7,444 dry tons per MW); 1400 green tons of MSW per MW	40 to 19,000 tons of wood chips per year; average facility is approximately 600 tons per year	6 tons of pellets per home[54]

Direct Combustion

Direct combustion of biomass for electricity production is a mature technology that includes many stand-alone grid power applications. It is also one of the few renewable electricity technologies well-suited to baseload electricity generation. Biomass resources best suited for direct combustion include: roundwood from new forest growth, sawmill residues, forest residues, urban wood residues, and some municipal solid wastes. Agricultural residues can be used in direct combustion as well, but due to their limited availability in the region, they are not typical inputs for large biomass energy plants.

[52] Sources used for information on feedstocks and conversion factors for each technology type include INRS 2008; Rutgers University 2007*;* and Antares 2008.
[53] This range does not include the efficiency of outdoor wood boilers (OWBs), which have efficiencies closer to 25 to 30 percent. These technologies have become popular in the Northeast due to high prices for home heating oil, but older versions of OWB technologies are being discouraged by state policies due to their high levels of air pollution.
[54] Based on an assumption of an average 2,000 sq. ft. home in New England (INRS 2008). Actual pellet use will vary depending on home size, location, quality of building shell, and other factors.

Biomass combined heat and power (CHP) systems are another form of direct combustion. These systems have the advantage of greater efficiency than stand-alone biomass electric units, due to the capture of both electricity and heat. They also have a long history of use in the forest industry, where pulp mills or sawmills have used their residues to generate electricity and process heat. Biomass CHP is now moving beyond the forest industry, and is especially attractive to industries with high heat and electricity demand.[55] Because a combustion technology is used, biomass CHP can take a variety of biomass types, including forest residues, new forest growth, sawmill residues, and urban wood residues.

Institutional and Residential Thermal

Institutional scale thermal energy systems are also a well-proven technology. Biomass thermal technologies have been installed at a number of facilities in the Northeast, including schools and other public institutions as well as for use in the forest products industry. New technologies are coming to market, facilitating the use of wood pellets for institutional and commercial scale thermal applications. These technologies hold substantial promise over more conventional methods. New advancements allow for the installation of thermal biomass systems at locations previously considered challenging, because pellets provide an opportunity for easier storage. A drawback of this method includes the air pollution profiles associated with some of these technologies. This is especially true with units that fall below current size thresholds for regulatory emissions limits.[56] Emissions of fine particulate matter are of special concern, given their potential for creating adverse impacts on sensitive populations.[57]

Anaerobic Digestion

Anaerobic digestion of biomass feedstocks is a well-developed process that is in wide use in food waste digesters, wastewater treatment plants, and on livestock farms. Landfill gas (i.e., methane) is the product of natural anaerobic digestion, and many landfills employ technology to capture the methane gas for use in power generation. Electric power production and CHP are common applications for the use of landfill gas.

5.3.2. Advanced Biomass Conversion Technologies

Over the long-term (2015 to 2020) timeframe, this analysis assumes that advanced biomass conversion technologies, including gasification, pyrolysis, enzymatic hydrolysis, and algae-derived fuels will become commercially viable. Table 5-7 displays some of the more promising advanced biomass conversion technologies that are currently under development.

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[55] For example, a large Anheuser Busch brewery in Merrimack, NH recently announced that it is evaluating biomass to meet the facility's sizeable electricity and thermal needs.
[56] NESCAUM is currently working with its states to identify the best available combustion technologies and emissions controls and to address market barriers that limit their presence in the marketplace.
[57] Potential emissions from these units are described in more detail in a 2009 NESCAUM study on wood combustion (*in progress*).

Table 5-7. Advanced Biomass Conversion Technologies under Development[58]

	Thermochemical Conversion		Biochemical Conversion	
	Gasification	Pyrolysis	Enzymatic Hydrolysis	Transesterification
Biomass Types	Wide range of feedstocks	Wide range of feedstocks	• Ag. residues • "Pre-treated" woody feedstocks and some solid waste	• Vegetable oils • Waste cooking oils • Algae
Products	"Syngas"	Bio-oil for combustion or conversion into transportation fuel	Cellulosic ethanol	Biodiesel
Probable size range at commercial scale	Varies widely, depending on technology and application	n/a	20 million gallons per year	n/a
Efficiency	As high as 75 percent, depending on technology and application	Possibly as high as 75 percent (intermediate product	n/a	n/a
Resource Use	Variable	Variable	80 to 100 gallons per dry ton	7.65 pounds oil per gallon biodiesel[59]

[58] Sources for conversion factors for advanced biofuels include INRS 2007, Rutgers University 2007, and Radich 1998.

Thermochemical Conversion: Gasification and Pyrolysis

Some gasification and pyrolysis technologies are currently commercially available, including gasification applications that use wood residues from MSW and C&D debris in power production. In the near future, commercial gasification applications may also be used to produce liquid transportation fuels. This created fuel, after cleaning and depending on the amount of heat and type of technology for infiltrating oxygen, may be used as a substitute for fuel or natural gas in existing boilers. It may also be further refined to be blended with, or used to replace, petroleum-based fuels.

Biomass integrated gasification combined cycle technology (BIGCC) utilizes both a gas and a steam turbine to increase the efficiency of producing electricity from biomass gasification. BIGCC technologies are developed, but thus far have limited commercial deployment due to heavy resource and infrastructure needs. The production of Fischer-Tropsch transportation fuels from the gas produced in gasification requires an oxygen-blown gasifier, a tar cracker, and considerable cleaning and refining.

Small-scale gasification for use with an internal combustion engine or a reciprocating engine is in limited use, but under development. This type of gasification is not as efficient as a BIGCC, but has the potential for more localized implementation.

Pyrolysis produces oils that can be used in power generation or, with significant upgrading, transportation fuels.

Biochemical Conversion: Enzymatic Hydrolysis

Dilute acid hydrolysis for biofuels is a future technology that is attractive for its ability to process a wide range of biomass feedstocks and convert them into a number of fuels suitable for transportation. These include MeTHF, a gasoline additive or replacement, and methyl- or ethyl-levulinate, which can be used as additives or replacements for diesel fuel or heating oil.

Cellulosic ethanol production, in particular technologies deploying enzymatic hydrolysis, is undergoing extensive research and development. Cellulosic ethanol could be developed from a range of feedstocks, including the organic portion of MSW and C&D debris. While pilot wood-to-ethanol facilities are under development in New York and Maine, and early commercial sites are under development outside of the region, we assume that cellulosic ethanol (or other biomass-based transportation fuels) will not be fully commercialized in the region within five years.

Modifications may be made to typical engines to use a blend of gasoline that contains 15 percent ethanol, and flexible fuel vehicles (FFVs) that allow the use of E85, or 85 percent ethanol fuel.

Transecterification

Conversion of lipid-containing feedstocks to biodiesel using transecterification is a mature technology. Most inputs, however, are virgin vegetable oils from food crops, such as canola, soy beans, sunflower, and palm, which are not currently produced in significant quantities in the Northeast. Although not usually produced at the commercial level, used cooking oils (yellow grease) may be used in place of diesel in a retrofit vehicle or be refined and converted to biodiesel.

Significant research is underway in the conversion of algal feedstocks into biodiesel. Algae, which are high in lipid content, are converted into biodiesel in one of two processes. Photosynthetic processes require light and a nutrient source that might be provided by waste streams such as municipal wastewater. Heterotrophic processes using fermentation require an alcohol (Spiro and Stigliani 2003).[60] Experimentation is currently underway at the University of New Hampshire and other places to use waste sugars in heterotrophic processes for fermentation (Aulisio 2009).

5.3.3. Summary of Woody, Agricultural, and Waste-based Biomass and Fuel Assessment

To summarize the assessment of biomass resources available for the production of low carbon fuels in the Northeast, Table 5-8 provides estimates of both "maximum" availability of woody, agricultural, and waste-based biomass categories, and the "likely" availability for those same resources. Note that the estimates of both maximum and likely biomass availability in the region are not inclusive of resources currently used in existing markets. In other words, all else being equal, this analysis assumes that these resources are less likely to create significant new pressure on national and international markets for biomass resources.

Table 5-8. Total Biomass Resources in the Northeast, Maximum and Likely Availability[61]

Type of Resource	Maximum Availability	Likely Availability
Woody biomass (dry tons)	33,463,889	5,021,667
Agricultural biomass (dry tons)	3,278,400	1,639,200
Municipal solid waste (dry tons)	66,492,294	20,390,809
Agr. and wastewater solids (dry tons)	11,880,541	5,940,271
Total Solid Biomass(dry tons)	**115,115,124**	**32,991,947**
Wastewater biogas (cubic ft.)	55,785,179	27,892,590
Waste oils (tons)	317,358	31,736

In addition, estimates of likely resource availability, while not reflecting any formal analysis of sustainability issues or market supply and demand, are relatively conservative percentages of the maximum availability. This is done to reflect the fact that a variety of factors, including (but not limited to) environmental concerns, market conditions, and landowner preferences, will substantially limit actual quantities of resources available for the production of low carbon fuels in the region.

[60] Heterotrophic organisms exist in environments without oxygen and therefore require simple organic molecules to obtain energy (Spiro and Stigliani 2003).

[61] States included in this assessment are the six New England states, New York, New Jersey, and Pennsylvania. Figures represent estimated resource availability on an annual basis.

Based on the application of these conservative percentages, likely availability for woody biomass resources are estimated to be 15 percent of maximum availability. With agricultural biomass and wastewater biogas, the likely availability is about 50 percent of maximum availability, and for waste oils, likely availability is estimated to be only 10 percent of maximum availability.[62]

A key insight from these estimates is that waste-based resources are by far the largest biomass resource available in the Northeast, totaling over 26 million dry tons between MSW and agricultural and wastewater solids. This is in comparison to about 6.6 million dry tons of woody and agricultural biomass combined. These substantial quantities of waste-based biomass are due primarily to the Northeast's large, dense population, which generates significant waste volumes even after removing from consideration those wastes that are candidates for reduction and recycling.[63] Another notable result is that the estimated likely availability of waste oils, which are also a function of population density, is very low. This reflects the fact that these wastes are used in many existing markets and that bioenergy applications will need to compete in the market for these resources.

Table 5-9 below shows the estimated volumes of low carbon fuel that could be produced using regional resources in the near-term (i.e., 2010) and the longer-term (i.e., 2020), based on assumptions about rate of conversion in Tables 5-5 and 5-6, respectively. Note that these estimates do not try to project future market conditions. Instead, they consider only the likely availability of resources and the most likely conversion pathway for each resource category, based on current practices and best expert judgment about future practices. Future competition for biomass resources, new public policies, the rate of technological development, and other factors will play a large role in determining the ultimate use of biomass and resulting volumes of low carbon fuels.

Table 5-9. Estimated Low Carbon Fuel Production from Likely Available Regional Resources, 2010 and 2020

Quantities of Low Carbon Fuel	2010	2020
Electricity (MW)	849	1,524
Thermal energy (no. of average homes heated)	400,000	1,000,000
Liquid fuels (million gallons)		
100% biodiesel	6.6	6.7
Cellulosic ethanol	--	440

Note that these volume figures are not mutually exclusive, meaning that the volumes of electricity, thermal energy, and liquid fuels shown below could all be

[62] There are numerous competing markets for waste oils, such as cosmetics and animal food products, so the likely availability of waste oils for bioenergy is estimated to be as low as 10 percent.
[63] The population of New England and the Mid-Atlantic together is estimated to be 97 million people in 2010 (U.S. Census Bureau 2008).

produced simultaneously from estimated available resources. So, by 2010, low carbon fuel production using only resources from the region could include nearly 850 MW of electricity, the thermal energy equivalent to heating 400,000 residences, and nearly 7 million gallons of biodiesel (equivalent to approximately 130 million gallons of B5).

Over the longer-term, more resources could become available to energy applications, thus the volumes of low carbon electricity and thermal energy are assumed to more or less double by 2020. The doubling results in 1,500 MW of electricity and thermal energy to heat approximately one million residences, respectively. Also, while liquid fuel production from regional resources would be very low by 2010, by 2020 there could be an estimated 440 million gallons of cellulosic ethanol produced if advanced fuel technologies gain commercial viability.

While these estimates of low carbon fuel quantities are relatively modest in proportion to the possible goals of a regional LCFS, this analysis is limited only to regional feedstocks. Implementation of a regional LCFS in the Northeast would certainly result in some feedstocks and low carbon fuels being imported from outside the region. In addition, these fuel quantities are based on relatively conservative estimates of likely feedstock availability. Depending on a variety of factors, including competing markets, environmental sustainability, and technological and policy changes, regional feedstocks could support substantially higher quantities of low carbon fuel production in the future.

5.4. Electricity

This analysis also considers electricity as a potential low carbon fuel for transportation when the electricity is used to operate light-duty, plug-in hybrid electric vehicles (PHEVs). Various components of PHEV technology are under development, but with improved battery storage for electricity and greater potential all-electric ranges (AERs), PHEVs could meet average daily travel needs for an increasing number of consumers. PHEVs are expected to be commercially available by 2010 from a number of vehicle manufacturers, and will be rechargeable at home or at the workplace.

Because electricity demand varies on a daily and seasonal basis, not all electric power production facilities operate all the time. Instead, the electric grid is carefully managed to meet demand with the most inexpensive electricity available at any given time. During times when electricity demand is lower, the system provides “baseload” generation, which draws from sources including coal, nuclear, run-of-river hydropower, and some renewable resources (wind and solar).

With RGGI and renewable energy requirements in place in most states in the Northeast, new sources of less carbon-intensive electricity should become more cost-competitive relative to traditional fossil-based resources. During peak hours, more expensive sources of power are called upon, including natural gas-fired combined cycle, some higher cost coal generation, natural gas turbines and diesel generators. Some of these sources designed to meet peak demand generate high levels of criteria air pollutants. Moreover, the capacity of the electricity grids in New England, New York, and the mid-Atlantic states are being increasingly challenged to meet growing demand during peak periods while also maintaining high levels of reliability. Therefore, it is important to consider when PHEVs are most likely to be charged by consumers to determine which types of generation sources are being used to meet electricity demand.

This analysis evaluates, in a very general sense, the effects on the Northeast's electric power system of new demand for electricity to power PHEVs. Depending on the number of PHEVs that enter the marketplace, the all-electric traveling range of the vehicles, the duration of vehicle charging time, and time of initial charge, incremental electricity demand from PHEVs may be met with existing generation and/or construction and dispatch of new generation resources.

To get a broad sense of the impacts of PHEVs on grid capacity, this analysis uses a very simple approach based on an examination of the typical annual load profile of each of the three electricity grids serving the Northeast.[64] This approach includes how electricity demand typically breaks out into peak and non-peak demand over the course of an average year, and which kind of generation resource is typically used to serve demand over the course of the average peak and non-peak day.[65]

Based on PHEV penetration levels from EPRI and NRDC (EPRI/NRDC 2007) and the NE-Vision model, penetration of PHEVs in 2020 was assumed to fall between about 2.3 million vehicles on the low-end and 7.2 million vehicles on the high-end for New England, New York, New Jersey, Pennsylvania, Maryland, and Delaware. Table 5-9 below shows the extra electricity capacity remaining (shown with a "+" symbol), or new capacity that would be required to meet additional electricity demand (shown with a "-" symbol), under different charging scenarios that combine vehicle numbers, charging time, charging duration, and vehicle technology (i.e., electric range of the vehicle).

As shown in the estimates of capacity in Table 5-10, most of the PHEV charging scenarios represented in this analysis could theoretically be met with existing generation resources. The exceptions to this are all PHEV charging scenarios with an initial charging time of 5 p.m. According to this analysis, new generation capacity would be required for all scenarios of vehicles charging at this time. Even if the number of PHEVs is on the low-end, those vehicles charge more slowly (i.e., 6 hours), and have a shorter electric range (i.e., 20 miles).

Since PHEVs in these scenarios will be competing for peak generation resources throughout most of the region, charging vehicles at 5 p.m. would likely require additional capacity to meet demand while maintaining the same level of reliability, all else being equal. However, there are significant efforts underway in the Northeast to reduce demand for electricity with substantial new investments in energy efficiency. Depending on whether these energy efficiency measures reduce demand during peak or other times will determine how they benefit the grid at different times of the day and throughout the year.

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[64] The three electricity grids included in this analysis are: ISO-New England, New York ISO, and the mid-Atlantic portion of the PJM grid. The combined capacity of these two grids plus the mid-Atlantic portion of the PJM grid is equal to 151,090 MW.

[65] A more detailed description of the methodology used in this analysis and underlying data can be found in Appendix D.

Table 5-10. Effects on Northeastern Grid Capacity of PHEV Charging Scenarios (in MW)

PHEV Charging Scenario			2010		2020	
Time of Initial Charge	Charge Duration	All-Electric Range	PHEV Penetration Level			
			Low	High	Low	High
9 a.m.	2-hour	20 mile	+29,366	+15,804	+33,187	+17,349
		40 mile	+18,202	+8,916	+30,625	+9,304
	6-hour	20 mile	+33,590	+29,070	+38,120	+32,841
		40 mile	+32,859	+26,774	+37,266	+30,159
5 p.m.	2-hour	20 mile	-5,185	-18,746	-5,983	-21,821
		40 mile	-16,349	-25,635	-8,544	-29,865
	6-hour	20 mile	-961	-5,481	-1,050	-6,329
		40 mile	-1,692	-7,777	-1,904	-9,011
12 a.m.	2-hour	20 mile	+41,047	+27,486	+46,566	+30,728
		40 mile	+29,833	+20,597	+44,004	+22,683
	6-hour	20 mile	+45,271	+40,751	+51,499	+46,219
		40 mile	+44,540	+38,455	+50,645	+43,538

To read the contents of the above table, a "+" symbol indicates available capacity in that amount for a given PHEV charging scenario, whereas a "-" symbol indicates a lack of capacity for a given charging scenario.

Note that a key limitation of this simplified approach to analyzing the impacts of PHEVs on the electric power system is that it does not consider the geographic location of electricity demand. This would require more sophisticated dispatch modeling. Dispatch modeling, while relatively resource-intensive, would provide a geographic dimension to identify the location of where new demand from PHEVs would occur, which in turn would suggest where new electricity capacity may be required. Obviously, electricity can only be supplied where generation is connected to infrastructure—transmission and distribution resources—that deliver electricity. Therefore, the physical location of where PHEVs are charged will have important implications for electricity transmission and distribution systems as well as grid capacity.

Additional transmission and distribution investments may be required if commuters to cities such as New York or Boston charge their PHEVs during the day. This is because substantial transmission constraints currently exist in greater Boston, New York City/Long Island, and the northeastern portion of New Jersey (Potomac Economics 2008). For example, in 2007, major interfaces in the New York City load pocket were congested 20 percent of the time, and constraints in New York City and Long Island along with local load pockets were substantial enough to raise prices in these zones (Potomac Economics 2008). In the case of the PJM Mid-Atlantic, northern New Jersey incurred over $200 million in congestion costs in 2007 (PJM Interconnection 2008). The constraints in Boston require less immediate attention, but could cause concern in a high-penetration PHEV scenario.

There are a range of options to influence when PHEV users charge their vehicles. Real-time metering and "cost at time of use" billing could compel some consumers to charge when there is less demand on the grid. Charging stations at major places of employment and in cities could provide incentives for consumers to charge when they arrive at work rather than when they arrive home, and timers placed in vehicles or wall sockets could be used to make charging late at night easier. Over time, investment in smart grid technologies could eventually lead to “vehicle-to-grid” (V2G) technologies that would allow consumers to charge PHEV batteries at low demand times and then sell stored electricity back to the grid during peak demand times.

5.5. Chapter Summary

Waste-based biomass is the region’s most significant resource by far, with a likely availability of 26 million tons of organic municipal solid waste plus agricultural wastes and wastewater solids under conservative estimates. In addition, nearly 30 million cubic feet of biogas will likely be available in the Northeast in 2020. These materials could be converted into over 484 MW of electricity.

More than 6 million tons of woody and agricultural biomass are likely available in the Northeast for thermal applications under conservative estimates. This biomass could be used to heat one million homes in 2020, displacing 660 million gallons of heating oil and lowering the carbon intensity of fuels used in diesel and thermal applications by 4.5 percent.

Nearly 7 million gallons of neat biodiesel could be produced from over 30,000 tons of likely available waste cooking oils in 2020 (assuming only the use of 10 percent of maximum available “yellow” grease). This is enough for 134 million gallons of B5 biodiesel blend.

Approximately 7 million dry tons of woody biomass are likely available for use in electric generation, with the potential to generate over 5 GWh per year. This represents more than one-third of total non-hydro renewable generation in 2005, and 8 percent of the total non-hydro renewables expected by 2020. This resource could earn credit towards Renewable Portfolio Standards in many states. Full implementation of RPS and RGGI by 2020 is expected to reduce the carbon intensity of electricity used in electric vehicles by 20 gCO_2e/MJ.

Regionally produced low carbon resources such as electricity, municipal solid waste, and woody biomass may have lower lifecycle carbon emissions, taking into account land-use changes, than do crop-based biomass resources from agricultural areas outside the region.

Key uncertainties apply to these estimates of available biomass resources—actual biomass availability will vary depending on key factors such as economic competition for resources, environmental concerns, landowner preferences, and public policies.

Because electric vehicles (EVs) have very efficient drivetrains compared to internal combustion engines, electricity is also a promising low carbon fuel for transportation applications. This is especially true in the Northeast, where new policies are in place to reduce the GHG intensity of electricity, including the Regional Greenhouse Gas Initiative (RGGI) and renewable energy standards.

Provided that PHEVs are charged when extra grid capacity and where appropriate transmission infrastructure exist, the Northeast’s electricity grids could support up to

7 million advanced PHEVs by 2020. This would represent over 20 percent of the light-duty fleet, and would require extremely aggressive market penetration beginning early in the next decade. This number of PHEVs could displace 2.2 billion gallons of gasoline annually.

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Chapter 3

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Appendix A: Scenario Analysis Appendix

Appendix A: Scenario Analysis Appendix

There were three distinct components to the scenario modeling exercise, each of which required the use of a particular modeling tool. The use of the three tools is illustrated schematically in Figure A-1, and each tool is described in summary below.

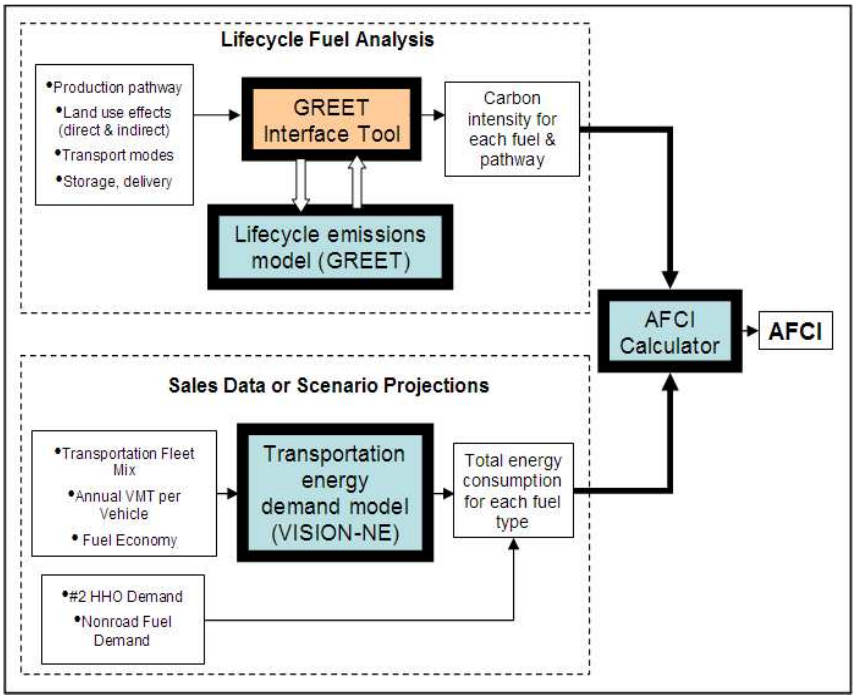

Figure A-1. AFCI Calculation Flowchart

A.1. GREET

First, we had to develop a lifecycle CI score for each potential fuel pathway as delivered and consumed in the northeast region. For this, we formed (with the assistance of subcontractor Life Cycle Associates) a set of Northeast-specific input parameters and a specialized interface tool for the GREET model. With these, we were able to run GREET to calculate Northeast-specific CI scores for each selected fuel pathway. Because the Interface Tool was designed to enable convenient operation of the GREET model specifically for the purpose of determining CI as defined under an LCFS, it is well suited for future use by stakeholders to model additional pathway scenarios. It could also be expanded upon further, for use in a regulatory context. A full description of the Interface Tool and input parameters are provided in Appendix B.

A.1.1 VISION-NE

In order to assess the potential to displace specified amounts of the projected energy demand with low carbon alternatives, we first needed to estimate the region-wide demand for transportation and home heating energy under a base-case scenario. Estimates of home heating energy demand were based on projections developed by the Energy Information Administration (EIA) and published in its Annual Energy Outlook (AEO) report. While AEO also includes projections of transportation energy demand, we required a more detailed profile of the fleet mix in order to assess certain technology-specific low carbon compliance options. The VISION model, developed by Argonne National Laboratory, is designed to generate detailed characterizations of future fleets, and to project the energy impacts for specified fleet penetrations of alternative vehicles and fuels. We developed a customized version of the VISION model, VISION-NE, in order to specifically characterize the Northeast's fleet, and made numerous additional changes to facilitate the consideration of issues particular to a low carbon fuels program.

Our approach to developing VISION-NE was to rely on the default VISION data and methodologies, and modify only where we had state/region-specific data or when there was other clear justification to do so. The primary modification was the replacement of national fleet population data with region-specific numbers, as described below. Key VISION default assumptions are summarized in Table A-1. Interested readers may refer to the VISION-NE spreadsheet, where all changes to the original VISION have been documented with color-coded worksheet tabs and the Excel Comments feature.

VISION projects future vehicle sales and energy consumption based on its stock profile. We obtained registry data on vehicle populations in six of the eight NESCAUM states for the baseline year of 2005. We then estimated the fleet populations in the remaining two states and added them together to arrive at a stock estimate for each vehicle category in the baseline year. Next, we applied the VISION-default growth rates for vehicle stock to our baseline year "seed" values, resulting in a projection of the Northeast's vehicle stock for each year from our 2005 baseline to the target year of 2020. VISION calculates new vehicle sales, VMT, and energy demand projections based on its vehicle stock data. Thus, modifying the key "seed" vehicle stock values was sufficient to adjust VISION's energy demand outputs to reflect the Northeast's fleet.

NESCCAF made numerous other adjustments to the core VISION model, and incorporated a number of post-processing calculators into the spreadsheet for ease of use. All changes and additions are highlighted and documented within the spreadsheet itself, which is available for download free of charge from the NESCCAF website, www.nesccaf.org.

Significant modifications to the core VISION model include:

- Extraction of fuel energy density values (by default hardwired for higher-heating values) and the addition of a LHV/HHV toggle to enable users to choose between HHV and LHV.
- Adjustment of light-duty vehicle fuel economy values to reflect changes to federal CAFE standards in the 2007 EISA.

- Adjustment of default ethanol volumes to reflect Northeast-specific sales data following the regional phase-out of M*t*BE.
- Optional manual override of VISION defaults for EV and PHEV fuel economy, PHEV all-electric range, and E85 VMT shares for flex-fuel vehicles.
- User-selectable vehicle stock profiles to enable analysis of a specified state or region.

Significant additional features include:

- Shortcuts to enable convenient modeling of specific policies such as California LEV/ZEV and federal RFS;
- Demand projections for nonroad gasoline, nonroad diesel, and No. 2 heating oil; option to include or exclude from baseline AFCI;
- Tar sands option enabling user to specify penetration of tar sands-based gasoline or diesel in both baseline and target years;
- Shortcuts for convenient modeling of user-specified penetration rates for biodiesel and CNG in highway, nonroad, and thermal applications, as well as wood pellets and electricity in thermal applications;
- "EV Calculator" to determine the CI for electricity based on vehicle technology and generation mix;
- Carbon intensity data for various fuel pathways, based on outputs from GREET as generated using the NE-GREET Interface Tool;
- "AFCI calculator" that incorporates energy demand and fuel pathway-specific carbon intensity values to arrive at the average fuel carbon intensity for a given scenario.

Table A-1. Key default assumptions in VISION-NE

	#	VISION Default	notes
Average PHEV All-Electric Range (AER)	22	No	Based on ARB ZEV ISOR Table 4.2. Increases linearly from 0 in 2010.
PHEV Electric VMT %	34%	Yes	Computed from AER per SAEJ1711
Baseline ethanol content	7.4%	No	Based on EIA volume sales data
Baseline ethanol CI	96.7 gCO_2e/MJ	No	Equivalent to gasoline CI
Baseline LDV MPG	CAFÉ	No	Per AEO 2008, based on 2007 EISA
2020 LT market share	52.9%	No	Per AEO 2008, based on 2007 EISA
LDV VMT Growth Rate	0.81%	Yes	

A.1.2 Integrated AFCI Calculator

Because an LCFS requires the determination of an average AFCI score, based on the fractions and individual CI ratings of every fuel type, we developed an AFCI calculator to incorporate the outputs of the GREET and VISION-NE modeling. We integrated this tool into the VISION-NE model for ease of use; however, it can be used as a stand-alone calculator, if desired, by providing alternative inputs for the CI scores and total demand volumes of individual fuel pathways. A screenshot of the Gasoline AFCI section of the AFCI Calculator interface is shown in Figure A-2. Note that values for CI and fuel volumes shown in this figure are examples representing one scenario. All CI values and volumes can be adjusted to model different scenarios using the main VISION-NE interface.

2020 GASOLINE					
	Baseline AFCI	**96.7**		Scenario AFCI	**96.7**
	Total Fuel Energy (mmBtu)	**2.40E+09**		AFCI Reduction	**0.0%**
Fuel	**Energy Density (BTU per gal, gge, or kwh)**	**Carbon Intensity (g/MJ)**	**Volume (Bgal or GWh)**	**Energy (mmBtu)**	**Energy Share**
LD Gasoline	113,602	96.7	18.7	2.13E+09	88.7%
LD Oilsand Gasoline	113,602	108	0.0	0	0%
HD Gasoline	113,602	96.7	0.399	4.53E+07	1.9%
HD Oilsand Gasoline	113,602	108	0.0	0	0%
LD CNG	113,602	73.1	0.0	6.13E+02	0%
Electricity for BEVs	3,412	28.4	0.0	0	0%
Electricity for PHEVs	3,412	47.4	0.0	0	0%
Baseline Ethanol	76,330	96.7	1.42	1.09E+08	4.5%
Advanced Ethanol	76,330	20.0	0.0	0	0%
RFS Cellulosic Ethanol	76,330	38.7	0.0	0	0%
RFS "Advanced" Ethanol	76,330	48.4	0.0	0	0%
RFS "New Conventional" Ethanol	76,330	77.4	0.0	0	0%
Nonroad gasoline	113,602	96.7	1.04	1.18E+08	4.9%

Figure A-2. AFCI Calculator gasoline interface with example values

As Figure A-2 illustrates, the AFCI calculator combines the total demand and carbon intensity for each fuel pathway, to arrive at the weighted average, or AFCI value, for a given scenario. Energy demand projections for most fuel types are provided by the main VISION model. The projections are based on fleet characteristics and penetration rates of specific vehicle and fuel technologies in the scenario year. This includes baseline ethanol, for which the user may select either the default value (based on regional sales data as described above), a region-wide E10 blend, or specify any other volume. The user may also choose the carbon intensity of baseline ethanol from a range of options. Volumes of tar sands-derived fuels are determined by the user-input tar sands share for both gasoline and diesel, and do not depend directly on the fleet profile. Similarly, the

RFS ethanol types automatically displace gasoline when the user selects the RFS toggle. A third category of ethanol may be modeled by entering the volume and CI values directly into the AFCI calculator sheet. Finally, the AFCI calculator adds nonroad fuel to the total by drawing demand estimates from the nonroad worksheet and database within VISION-NE.

A.1.3 Supplemental Analyses

In addition to these three main steps, several aspects of the scenario's analysis required additional post-processing or other special treatment. For example, the carbon intensity for electricity as used in BEVs and PHEVs is a function of both the electrical grid and the relative efficiency of the vehicle itself. We developed an EV calculator to facilitate analysis of EV-specific scenarios. Supplemental analyses were also required to estimate the impact of the federal RFS on baseline biofuel volumes in the Northeast, and to project the electrical grid characteristics in the 2020 target year assuming implementation of state-specific renewable portfolio standards (RPS) and of the Regional Greenhouse Gas Initiative (RGGI) for the power sector. These supplemental analyses are described in more detail below.

A.1.4 Electric-Drive Vehicles

The carbon intensity of electricity as used in electric-drive vehicles is a function of vehicle characteristics, driver behavior, and the mix of generating technologies employed. GREET generates GHG emission factors for a given generation mix, reflecting the emissions associated with the production and transmission of electrical power up to the point of delivery (the "plug"). While GREET's calculation methodology is the same for electricity and liquid fuels, comparison of upstream emissions at the point of delivery is not especially meaningful due to the difference in quality of each energy type. Therefore, an adjustment is needed in order to compare carbon intensity values for each fuel pathway on an equivalent basis.

Electricity at the plug is a very high-quality energy type, ready for immediate and efficient conversion to motive power. On the other hand, liquid transportation fuels are of inherently lower quality since their chemical potential energy must still be converted to useful energy through a process that invariably involves significant losses. Thus, a BTU of liquid fuel "at the pump" is less useful than a BTU of electricity "at the plug." This difference in energy quality is reflected in the superior energy economy of electric-drive vehicles compared to liquid-fueled vehicles – an EV will travel a greater distance per unit of energy than a comparable gasoline-powered vehicle. It should be noted that this difference does not necessarily suggest an inherent efficiency benefit for EVs on a lifecycle basis (although many EVs are indeed more efficient than comparable gasoline-powered vehicles). Rather, it reflects the fact that the thermodynamic losses associated with energy conversion have already occurred by the time electricity is consumed at the plug, whereas they have yet to occur for liquid fuel at the time of retail purchase.

For conventional power plants, the difference in energy quality and the precise location of thermodynamic losses may seem academic. It is tempting to consider the power plant-EV pathway as a single system, where only the CI of the input fuel would be of interest and no vehicle efficiency adjustment would be necessary. However, electric vehicles are fundamentally different from conventional fuel-vehicle systems in that the fuel source is separated from the end-use technology. Whereas an internal combustion engine can operate only on fuels with very specific properties, electricity for an EV can be generated using a wide range of fuels, technologies, and distribution pathways, some of which may be much less carbon intensive than others. It is because electric-drive vehicles can run on low carbon electricity, coupled with their efficient design, that they represent a potentially attractive LCFS compliance pathway.

A.1.4.1 Energy Economy Ratio

The difference in energy quality means that a transportation consumer of electricity would get more utility (i.e., travel a greater distance) than a gasoline consumer for the same amount of energy. Because the value of electricity in a low carbon fuels program is to displace conventional fuels with low carbon substitutes, it is important to know the amount of gasoline that would be displaced if a consumer were to switch from a conventional vehicle to an EV. If we assume that this consumer's travel demand is fixed (i.e., that she desires to travel a set distance regardless of the type of car she is using), then the amount of displaced gasoline energy would be equal to the energy consumed by the EV multiplied by the ratio of the EV energy economy (in miles per gasoline-gallon equivalent or mpgge) to the fuel economy of the gasoline vehicle (in miles per gallon). This ratio has been defined by CARB as the Energy Economy Ratio (EER). CARB has proposed to use an EER of 4.0 for battery-electric vehicles (BEVs) and 2.4 for PHEVs (for hybrid vehicles, the EER only applies when operating in all-electric mode).

NESCCAF has adopted CARB's EER values for the scenario analyses developed for this report.[66] We further assumed that use of electric-drive vehicles would displace use of average conventional vehicles – therefore the average energy economy of these vehicles would be 4.0 or 2.4 times the fleet average fuel economy as determined by the federal CAFE standards. Because the carbon intensity is a measure of emissions per unit of energy consumed, it follows that the *effective* carbon intensity of electricity used in transportation would be equal to the CI of the grid (see below) divided by the EER.

A.1.4.2 Grid Mix

As discussed above, the carbon intensity of electricity depends heavily on the fuels and technologies used for power generation. We used the Northeast GREET Interface Tool to develop carbon intensity values for each grid profile. Figure 3-12 in Chapter 3 compares the CI of electricity for a number of grid profiles, assuming EER values of 4.0 for EVs and 2.4 for PHEVs.

The mix of generating technologies used to provide electricity to EVs and PHEVs will depend on numerous factors, including vehicle design, driver behavior, and the

[66] In practice, the EER is likely to vary from one vehicle to the next, and possibly even from one user to another for a given vehicle type. While it seems reasonable to assume that an EV in general would displace a conventional vehicle with similar design and performance parameters, it is possible that EVs, particularly those with limited range or cargo capacity, would be purchased as a second or third vehicle for a household and used only for selected purposes, such as short local trips. In this case, the EV would displace gasoline that might be used by a much larger vehicle, resulting in an effective EER that is much higher than average.

number of electric-drive vehicles in the fleet at a given time. Chapter 5 includes a discussion of the challenges inherent in identifying the appropriate grid mix to assume for EV and PHEV charging.

GREET enables the user to characterize the grid mix by specifying the contribution of six technology categories: Oil, Natural Gas, Coal, Nuclear, Biomass, and "Other". GREET then calculates the carbon intensity of each generation technology and provides an average based on the user-specified grid shares. NESCCAF used GREET to evaluate the carbon intensity for each individual generator type and four grid mixes: the GREET-default U.S. and California average mixes, and average northeast generation mix in 2005 and as projected for 2020. Both northeast grid mixes were obtained by NESCCAF using the MARKAL model; the 2020 projection includes effects of RGGI and full implementation of Renewable Portfolio Standards (RPS) in each state as appropriate.

A.1.5 Renewable Fuel Standard

NESCCAF needed to project the impact of the federal Renewable Fuel Standard, recently modified by the Energy Independence and Security Act of 2007 (EISA). While the RFS sets very specific volume requirements for several categories of low carbon fuel, it does not specify where within the U.S. these volumes are to be sold. Thus, the Northeast could receive greater or lesser shares than the national average of each fuel type. NESCCAF did not attempt to predict the likely regional deployment profile for these RFS-mandated biofuels. Rather, we assumed in our scenario projections that RFS volumes were supplied to the Northeast in proportion to the region's share of national fuel demand, which we found to be 12 percent. Thus, we assume that the federal RFS will result in 1.3 billion gallons of cellulosic ethanol (achieving a 60 percent reduction in carbon intensity compared to the gasoline baseline), 300 million gallons of "advanced" ethanol (50 percent lower carbon intensity), and 200 million gallons of "new" corn ethanol (20 percent lower carbon intensity) delivered in the Northeast by 2020.

A.1.6 Thermal and nonroad demand projections

The VISION model considers only energy demand associated with highway vehicles. However, NESCCAF desired to evaluate the potential to include fuel used in nonroad equipment (e.g., construction equipment, lawnmowers, etc) as well as home heating oil within the scope of a regional LCFS. We therefore needed to estimate the baseline and future-year energy demand for these liquid fuels. We relied on the EPA NONROAD model to develop baseline and scenario year estimates for nonroad land-based equipment. We used EIA's Annual Energy Outlook to estimate regional demand for No. 2 heating oil and distillate fuel used in marine and locomotive applications. Our baseline inventory effort is described in detail in Appendix C.

Appendix B: Report by Life Cycle Associates, LLC: Requirements for Developing a Low Carbon Fuel Standard for Northeast States

LCA-6006-4P.2009
April 2009

Requirements for Developing a Low Carbon Fuel Standard for Northeast States

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1 Introduction

A Low-Carbon Fuel Standard (LCFS) regulates entities as well as unregulated fuel producers selling into the transportation fuel market based on specific global warming intensities (GWI) for a variety of transportation fuels. The GWI will be based on individual fuel production pathways, reflecting specific input parameters, transport distances and emission factors. Regulated entities will need to use these GWI values to calculate their overall Average Fuel Carbon Intensity to demonstrate compliance with LCFS.

Fuel Cycle models such as GREET (from Argonne National Laboratory[1]) have been used to determine the greenhouse gas (GHG) emissions from fuels for a variety of fuels pathways. GREET involves a wide variety of inputs to determine the GHG emissions from a variety of conventional and alternative fueled pathways. Entering appropriate data to the GREET model requires careful attention to many parameters such as fuel conversion efficiency, resource mix, transportation distance and other factors.

Implementers of an LCFS will need to perform these calculations to assess the potential for GHG reductions, analyze the GWI of specific fuel pathways, and develop compliance calculators. These calculations will include a number of determinations about system boundaries, fuel categorization, co-products, and other inputs. Calculating the GWI associated with an array of assumptions becomes increasingly complex.

1.1 Objective

The objective of this project is to provide NESCCAF with a robust, easy-to-use modeling tool for assessing the GWI for a wide range of fuels and scenarios and to use this tool to calculate the GWI (in g CO_2 /MJ fuel) for transport fuels in Northeast states under an LCFS. This analysis includes characterization of all fuel pathways considered, including determination of system boundaries, co-product credits, regional transportation distances and modes and electricity generation mixes.

1.2 Low Carbon Fuel Standard (LCFS) Logistical and Analytical Requirements

Implementing an LCFS in the Northeast States will involve many of the steps currently occurring in the rulemaking process for the California LCFS.[2] The Northeast states can therefore save considerable time and effort by building upon, rather than duplicating, the California effort. Many of the analytical tasks are comparable for both California and the Northeast states, including:

- Develop life cycle analysis protocols for low carbon fuels
- Assess vehicle fuel economy adjustments for alternative fueled vehicles
- Develop certification tool for fuel providers
- Determine certification, labeling, and other implementation requirements

These topics have received considerable examination under the California LCFS and the Northeast states can likely exploit these prior efforts.

[1]Source GREET model information: http://www.transportation.anl.gov/software/GREET/
[2] Source LCFS details and documentation: http://www.arb.ca.gov/fuels/lcfs/lcfs.htm).

Several other analytical questions are location and context dependent. These include, but are not limited to:

- Develop life cycle analysis of regional baseline
- Develop regional default values for individual factors and fuel ratings
- Analyze fuel pathways that may not be considered in California
- Issues relating to a multi-state versus single-state initiative

To help the Northeast States develop the necessary tools and procedures for an LCFS, Life Cycle Associates examined the analysis requirements for a regional LCFS and developed a spreadsheet tool to interface with the GREET model to input data for a variety of fuel pathways that are relevant for the Northeast states. The Northeast specific parameters and analysis tool are documented in this report.

This report provides no documentation on the GREET model or fuel pathways. A detailed description of fuel pathways can be found on the California ARB's web page for the LCFS[3]. The GREET model is documented with several reports and presentation by Argonne National Laboratory[4]. The 1999 documentation provides the most comprehensive explanation of the model Wang 1999). Subsequent reports and publications detail the inputs for new data and pathways.

1.3 Report Contents

The contents of this report are outlined in the following sections:

1 Introduction
2 Life Cycle Definition
3 Life Cycle Input Parameters
4 Analysis Tools
5 Results and Discussion

1.4 Project Deliverables

Project deliverables are shown according to report section below in Table 1.1.

[3] www.arb.ca.gov/fuels/lcfs/lcfs.htm
[4] http://www.transportation.anl.gov/modeling_simulation/GREET/index.html

Table 1.1. Project Deliverables and Report Section.

Deliverable	Report Sections
1. Documentation of input parameters required for assessment of lifecycle GWI for transportation fuels consumed in the Northeast region.	3.1, 3.2, 3.3, 3.4
2. Description and discussion of key differences in GWI values for baseline fuels consumed in the Northeast as compared to the California and transportation fuel markets.	5
3. Discussion of implications for the GWI of natural-gas-based fuel pathways of the northeast region's distinct mix of liquefied natural gas (LNG) and conventional pipeline gas.	3.2.2
4. Input configuration file to populate the GREET model with northeast-specific parameters for the 2005 baseline fuels mix, run the model and extract results.	4
5. Identify fuel pathway and parameter default values for low-carbon alternative fuels that are likely to differ for the Northeast market from those assigned in California. Provide guidance about modifying these parameters in GREET.	3, 3.6
6. Create a wood pellets for home heating fuel pathway tab in Interface Tool file for modeling the GWI of pellets produced from forestry residue, lumber mill residue and farmed trees.	3.5
7. Description and discussion of key issues that distinguish regionally-produced forest residue-based fuels	3.4, 3.5

2 Life Cycle Definition

This study supports calculations of the life cycle of fuels in support of a low carbon fuel standard. The life cycle components include the well to tank (WTT) and tank to wheel (TTW) components. The WTT phase includes the upstream or fuel cycle emissions. The TTW phase includes the emissions from the vehicle including fuel carbon converted to CO_2 as well as N_2O and CH_4 emissions generated by the combustion process. The terms WTT and TTW are also applied to the fuel cycle and fuel combustion phase for wood fuel pellets.

2.1 System Boundary Life Cycle Inputs Parameters

The system boundaries for the LCFS are likely to encompass regional and process specific parameters. Parameters needed for analysis of Northeast (NE) fuels include specific transportation distances, resource mixes (including electricity), and fuel processing inputs and efficiencies and emission factors. This study provides calculations of GHG emissions using the GREET model. The use of the GREET model also enables the calculation of criteria pollutant emissions, which are not examined here. The life cycle analysis requirements for both the NE LCFS and the CA LCFS differ from the average results that are defaults in the GREET model.

2.2 LCFS Analysis Requirements

This section briefly discusses the state of life cycle model development and the need for a pathway-specific model Interface Tool.

Fuel cycle assessment tools such as GREET and LEM were designed to analyze average production pathways for a very wide range of fuels and vehicles on an average basis. Modifying these spreadsheets to represent specific fuel pathways is a laborious, hard-to-verify, error-prone task. For example, GREET provides estimates of the GWI for ethanol produced from several different feedstocks, but several key assumptions are exogenous to the model and must be computed off-sheet if different values are to be used. Moreover, such changes would not be readily visible to anyone reviewing the spreadsheet.

Due to this orientation toward average pathways, GREET allows only a single specification of each fuel type which is applied globally throughout the model. For example, a resource mix can be selected to calculate emissions for the electricity grid, but these values are then applied everywhere electricity is required. There is no way to specify, for example, use of the Midwest grid for corn production from the more natural gas intensive California grid for ethanol conversion. These types of customizations are simply beyond the design parameters for the model.

The LCFS requires pathway-specific LCA tools which address the process-specific factors for individual fuel providers as well as the energy resource conditions and environmental factors that pertain to where the fuel is used. Several features are required by LCFS stakeholders that are beyond the design parameters of fuel cycle models such GREET and LEM, including:

1. Data entry sheets tailored to specific fuel types and pathways that organize all key inputs in one place
2. Ability to specify different fuel and electricity emissions factors for distinct phases of the production pathway (e.g. Midwest electricity for corn production and California electricity for biorefining)
3. Ability to incorporate economic and land use change data into the GWI analysis.
4. Separation between the specific pathway for a fuel being certified (e.g. diesel from a specific refinery), and other uses of that fuel type elsewhere in the model (e.g. generic diesel used for transportation of inputs)
5. Ability to specify the pre-computed GWI of blendstocks, e.g. purchased ethanol
6. Database of default GWI values for various parameters and blendstocks
7. Tracking of emissions by airshed, rather than simply “urban” vs. “total”
8. Reporting tools that generate certifiable data summaries, as well as digital data that can be transmitted to upstream entities for their own calculations

These features will need to be either layered on top of an existing fuel cycle model, or integrated with one. In order to analyze the GWI for fuel scenarios in the NE states, an Interface Tool interacts with GREET to calculate the emissions for a variety of fuel pathways. The approach for addressing the analysis issues and limitations are discussed below.

2.3 Modeling Requirements

2.3.1. Life Cycle Criteria

Life cycle criteria used to compare fuel pathways include the fuel cycle or WTT energy and greenhouse emissions and combustion emissions (TTW), which are presented in distinct categories.

For transportation fuels, the GWI is calculated with the functional unit of 1 megajoule (MJ) of fuel energy on a lower heating value (LHV) basis. The GWI includes both the WTT and TTW components. Combustion emissions include the fossil carbon in fuel (expressed as CO_2) and vehicle methane (CH_4) and nitrous oxide (N_2O) emissions. Note that the vehicle CH_4 and N_2O emissions are also expressed on a per MJ basis. Even though vehicles are regulated on a per mile basis, the energy specific representation correlates as well to actual emissions as mileage specific estimates (Unnasch 2005). An example of the GWI values calculated for RFG is shown in Table 2.1. The WTT energy indicates that 293,867 Btu of total energy are required to produce 1 mmBtu of fuel.

Table 2.1. GWI Results for RFG.

RFG GWI Results	GHG Emissions
WTT energy (Btu/mmBtu)	293,867
CH_4 (g/mmBtu)	110.015
N_2O (g/mmBtu)	2.097
CO_2 (g/mmBtu)	21,221
WTT GHG Emissions (g/mmBtu)	24,597
Fossil Carbon Content of Fuel (g/mmBtu)	74,030
Vehicle CH_4 and N_2O Emissions	2,610
Total WTT + Carbon in fuel + Vehicle emissions (g/MJ)	101,236
Total WTT + carbon in fuel (g/MJ)	**96.0**

The GWI calculations in Table 2.2 show the fossil carbon separately from biogenic carbon in fuel for corn based ethanol. The definition of GWI used here does not include the biogenic carbon in the WTT phase or the TTW phase as the net impact of biogenic carbon is zero. Carbon in fuel derived from biogenic sources (crop or biomass sources) is omitted because it was recently removed from atmosphere during feedstock cultivation. This distinction between biogenic carbon and fossil carbon does not account for increases in atmospheric carbon uptake due to increases in feedstock production or any impacts associated with land use conversion. GREET assigns a 195 g CO_2/bu burden for corn-based fuel pathways (ethanol and butanol), -112,500 g CO_2/ton for farmed trees ethanol and -48,500 g CO_2/ton for herbaceous biomass-based ethanol. These values are exogenous default inputs in GREET. Land use conversion and other potential multi-media impacts for alternative and conventional fuel pathways in GREET could be considered separately, outside of the life cycle model and added into the fuel cycle results; these impacts are not considered in this analysis as useful results in these areas are still emerging and not yet available. Section 3.7 briefly discusses the issues associated with direct and indirect land-use conversion.

This approach is simplest since biogenic carbon is not always consistently identified in fuel cycle models, even though these models treat the net WTW emissions with zero CO_2 emissions for biogenic carbon. The calculations are simpler without tracking the negative value associated with carbon uptake from the atmosphere. Charts showing negative GHG emission results are also confusing. In order to track biogenic carbon, Table 2.2 shows these emissions as a negative value during fuel production and a positive value during vehicle operation in a separate column. The total of fossil plus biogenic carbon corresponds to the accounting method used in the GREET model with the same overall GWI results as fossil carbon only method, because emission credits are given to the biogenic carbon in WTT results in GREET. The WTT results in the total column shows the comparable WTT results in the GREET model. The table shows that both accounting methods yield the same WTT results, as they both assume that biogenic carbon does not contribute to climate change or to a fuel pathway's GWI.

Table 2.2. GWI Results for anhydrous ethanol.

Anhydrous EtOH (E100)	**GWI with Fossil Carbon**	**Biogenic Carbon in Fuel**	**Total**
WTT Energy (Btu/mmBtu)	1,518,865		
CH_4 (g/mmBtu)	126.164		126.164
N_2O (g/mmBtu)	47.980		47.980
CO_2 (g/mmBtu)	57,746	-74,925	-17,179
WTT GHG Emissions (g/mmBtu)	75,198	-74,925	273
Fossil Carbon Content of Fuel (g/mmBtu)	0	74,925	74,925
Total WTT + Carbon in Fuel (g/mmBtu)	75,198	0	75,198
Total WTT + Carbon in Fuel (g/MJ)	**71.3**	**0**	**71.3**

The GWI can be adjusted based on the energy economy ratio (EER) for specific vehicle propulsion technologies to facilitate comparison of fuels used in vehicles with significantly different fuel economies. EERs are not applied in this report.

The Interface Tool also calculates the GWI for home heating fuels. This calculation includes both the WTT component from GREET and "TTW" or fuel combustion component[5]. The combustion component includes the fuel carbon as well as the CH_4 and N_2O emissions from combustion. For home heating fuels, the functional unit is MJ of heat in the fuel on an LHV basis with the assumption that 1 MJ provides the same level of heat and comparable fuel consumption for different fuels. The LHV is a better metric of heat available for home heating than the HHV because most heating appliances do not recover heat from the condensation of water vapor. Some furnaces are equipped with condensing heat exchangers which are more efficient than conventional and older designs. The GWI can be adjusted for the efficiency of the home heating appliance as more data become available.

The Pellet Fuels Institute[6] provides a comparison of the energy costs and efficiencies for different fuels showing the cost and combustion efficiency on a higher heating value basis. Note that most metrics of home heating fuel in the U.S. are on a higher heating value basis. Therefore,

[5] The end use for home heating fuels is also examined here with the TTW component referring to the fuel's end use.
[6] http://www.pelletheat.org/3/residential/compareFuel.cfm

any adjustments for fuel efficiency would need to convert higher heating value efficiency to lower heating value efficiency.

2.3.2. GREET Model Inputs

Inputs to the GREET model (or any LCA model) include energy (consumption factors and process efficiencies) and chemical/material inputs to each stage of the fuel pathway, yield factors for production processes, regional resource mix, transportation modes and distances, equipment emission factors, co-product yields and method for calculating co-product credits. Most of these input parameters are regional and/or process specific in nature and must be specified for each individual fuel pathway scenario.

2.4 Fuel Pathways

The fuel pathways modeled in the Interface Tool and considered in this report are shown below in Table 2.3. These pathways include petroleum fuels, traditional biofuels imported from the Midwest, and alternative fuels produced in the Northeast. The tool also enables the calculation of blended fuels based on separate calculations and inputs for the blending components. The tool was also configured to determine the GWI of home heating fuels including home heating oil, natural gas, and wood pellets.

2.5 Northeast Average Energy and Emission Inputs

The transportation distances, resource mix, and other fuel cycle parameters for baseline gasoline and diesel, electricity, and other fuels used in the Northeast will differ from the U.S. average or the values used for California's LCFS. These data are consolidated and organized for input to the GREET model in the Northeast GREET Interface file, provided to NESCCAF. The LCFS analysis for California accounts for the transportation distances and modes for fuel delivery; a similar analysis is conducted for fuel delivery to the Northeast. The GREET Interface can readily populate the same GREET model used for the California LCFS analysis.

2.6 Modeling Approach

The GREET user Interface Tool enables the calculation of process specific fuel cycle calculations. Life Cycle Associates' Peek/Poke technique populates the GREET model with new inputs using a simple Visual Basic macro. The macro plugs in the new data and extracts the model results. The tool includes an organized user interface for both process specific and average process fuel pathways. The tool first "pokes", or inserts, the user input data into GREET via the macro for each model scenario. The results are then "peeked" from the GREET model.

Table 2.3. Fuel Pathways Considered.

Feedstock/ Blendstock	Fuel	Fuel Type	Description
Crude Oil	Reformulated Gasoline Blendstock for Oxygenate Blending (RBOB)	Conventional Petroleum Blendstock	RBOB is blended with denatured ethanol to yield RFG
Crude Oil	Ethanol Denaturant	Conventional Petroleum Blendstock	Conventional gasoline or RBOB used to denature ethanol
Crude Oil	Ultra-Low Sulfur Diesel (ULSD)	Conventional Petroleum Fuel/Blendstock	ULSD for use in the NE
Crude Oil	Conventional Diesel	Conventional Petroleum Fuel	Conventional diesel used for transport of other fuels
RBOB, Denatured Ethanol	Reformulated Gasoline (RFG)	Blended Fuel	RFG for light duty vehicle use in the NE
ULSD, FAME/NERD	Biodiesel Blends	Blended Fuel	Low to high level biodiesel blends of ULSD and FAME or NERD
Natural Gas	Compressed Natural Gas (CNG)	NG-Based Fuel	CNG from North American or non-North American NG
Natural Gas	Liquefied Natural Gas (LNG)	NG-Based Fuel	Non-North American NG imported by ocean tanker
Corn	Ethanol	Alternative Fuel	Ethanol produced from Midwest corn through fermentation
Farmed Trees	Ethanol	Alternative Fuel	Ethanol produced from farmed trees through fermentation
Forestry Residue	Ethanol	Alternative Fuel	Ethanol produced from forestry residue through fermentation
Forestry Residue	Ethanol	Alternative Fuel	Ethanol produced from forestry residue through gasification
Soybeans	Biodiesel/Renewable Diesel (FAME/NERD)	Alternative Fuel	Esterified (FAME) or non-ester renewable diesel (NERD)[1]
Power Generation Feedstocks[2]	Electricity	Energy Carrier	NE electricity generation mix
Crude Oil	Ultra-Low Sulfur Diesel (ULSD)	Home Heating Oil	ULSD for use in the NE
Natural Gas	Natural gas	Home Heating Fuel	North American natural gas
Forestry Residue/ Lumber Mill Residue/ Farmed Trees	Wood Pellets	Home Heating Solid Fuel	Wood pellets used for home heating

[1]FAME = fatty acid methyl ester, referred to as biodiesel; NERD = non-ester renewable diesel, referred to as renewable diesel.
[2]Electricity generation feedstocks include residual oil, natural gas, coal, nuclear, biomass and renewables (solar, wind, geothermal and hydro).

Table 2.4 summarizes the Interface Tool approach for key analysis issues and Table 2.5 summarizes the basic functionality of the tool. The tool solves many of the issues related to process specific fuel cycle analysis by allowing the calculation of regional specific parameters for each fuel pathways.

Table 2.4. GREET Interface Tool Treatment of Key Input Categories.

Fuel Cycle Parameters	**Fuel Cycle Tool Approach**
Process Specific Inputs	Organize key parameterized process inputs for fuel pathways in fuel input sheets
Regional Electricity Mix	Select separate electricity mix for feedstock and refining phases from a list or specify individual fuel generation shares
Transportation Distance	Transport distances and mode shares organized in intuitive matrix format for most fuels; petroleum transport is similarly organized with three input categories: share of product (e.g., % of crude from Alaska), mode share (e.g., share of Alaskan crude transported by pipeline), and distance (e.g., 4,000 miles).
NE Petroleum	Specify inputs for all petroleum refinery products in one input sheet
Ethanol Energy Input	Thermal process energy (Btu/gal) and electrical power (kWh/gal) inputs instead of a modeling ethanol production with fuel shares and a total energy input
Ethanol Co-Product Treatment	Specify the DGS yield, share of DGS dried to yield DDGS, energy input for drying, share of DDGS combusted as process fuel, co-product displacement ratios and DDGS share consumed by new feed markets
Biodiesel Inputs	Similarly to ethanol, energy and electricity for soy oil extraction are input in their respective units (Btu/lb and kWh/lb); energy inputs for biodiesel and renewable diesel (I and II) production
Biodiesel Co-Product Treatment	Select the method for calculating co-product credits for biodiesel and renewable diesel (I and II) and specify products displaced by co-products when using displacement method
Biofuel Sustainability Credit	Exogenous input parameter allows GHG credit (or burden) to be assigned to corn ethanol or soy biodiesel for feedstock cultivation

Table 2.5. Summary of GREET Interface Tool Functionality.

Model Calculations and Features	**Fuel Cycle Tool Approach**
Blended Fuels	Calculate separate life cycle results for each blending component, including all distribution steps, and inserts the results into the "RFG" and "BD Blends" sheet to determine blended fuel results
Self documentation	Input sheets for each pathway provide documentation of key assumptions and "Defaults" sheet documents average default fuel pathway inputs
Life Cycle Results	Extract life cycle energy and emission results for each fuel pathway are extracted and present in the relevant fuel input sheet
GHG Emissions	Determine fuel cycle GHG emissions as a sum as WTT emissions and combustion emissions, consisting of fossil carbon in fuel and vehicle methane (CH_4) and nitrous oxide (N_2O) emissions.

3 Life Cycle Input Parameters

All of the input parameters for Northeast petroleum-based fuels and the Northeast-specific parameters (parameter values that differ from GREET default values) for the remaining fuel pathways shown in Table 2.3 are presented in this section. It should be noted that default values are referred to many times in the following sections and there are two primary types of default values. GREET default values, colored yellow in the GREET Interface Tool input sheets, are default values from an unmodified version of GREET 1.8b. Defaults in the GREET interface fuel input sheets (colored light red) and in the "Defaults" tab are the default input values configured to represent fuels used in the Northeast U.S. These values are regional in nature and differ from the CA-specific pathways (CARBOB, CA ULSD input sheets), which have CA-specific input parameters.

Each fuel pathway is documented in a tab of the Northeast GREET Interface Tool. The tool identifies the key inputs to the fuel pathway and allows for a simple overview of the inputs to GREET. Certain regional and process specific calculations are also possible with the tool. Most significantly, the electricity resource mix is specified separately for feedstock production and fuel refining. The tool aggregates the results using the GREET model separately and then sums these together for a complete fuel pathway.

3.1 Electricity Mix

The electricity generation mix is represented by a set of fuel share inputs that determine the carbon intensity of electricity used throughout the fuel pathway and it varies significantly among the different generation mixes. A variety of assumptions on generation resource mix can be applied to life cycle analysis including:

- Regional or U.S. average
- Marginal – referring to an assessment of the resource mix for permanent and sustainable load growth
- Dispatch based attribution – based on measuring or modeling the response of the system load to a short term increment of load

The assumed transmission loss is 8.1% and the natural gas-fired generation efficiency inputs have been adjusted down slightly from the GREET default values to reflect industry best estimates—see Table 3.2. Generation efficiencies for residual oil, coal, biomass and the nuclear input parameters are based on the CA LCFS values, which may better reflect real world generation efficiencies than the GREET defaults.

The main electricity mixes pertinent to fuels used in the Northeast are the U.S. average, Midwest average, NE U.S. average and NE U.S. marginal mixes. The GREET model includes the U.S., NE U.S. and CA average electricity mixes (included in the user interface).

This report calculates the electricity pathway using the Northeast marginal electricity mix shown below in Table 3.1, which has a dominant coal (51.6%) component and significant natural gas (33.5%) share. The marginal resources are assumed to be the same as the average without nuclear or residual oil fired power. These resources would not grow in response to a growing electricity demand associated with new fuels. The GREET values for residual oil and nuclear shares are set to zero and the remaining electricity fuel shares renormalized to 100%. Other assessments of the distribution between coal, natural gas, biomass, and non combustion renewables could also be envisioned given the constraints of the RGGI program and other measures to reduce GHG emissions. The Interface Tool facilitates quick and easy assessment of different electricity mixes used in a fuel pathway, even when different mixes for feedstock production and fuel production are desired. Table 3.1 shows the electricity mixes used in this report and built into the Interface Tool and their sources.

Table 3.1. Electricity Generation Mixes Used in Analysis.

Source	**GREET 1.8b**			**Modified GREET 1.8b[1]**	**Modified GREET 1.8b[2]**	**eGRID**
Electricity Mix:	U.S. Average	NE Average	CA Average	CA marginal	NE marginal	IL Average (SERC Region)
Residual oil	2.7%	6.6%	0.1%	0.0%	0.0%	1.5%
Natural gas	18.9%	20.9%	43.1%	78.7%	33.5%	11.8%
Coal	50.7%	32.2%	15.4%	0.0%	51.6%	57.3%
Nuclear power	18.7%	31.0%	14.8%	0.0%	0.0%	24.3%
Biomass	1.3%	3.6%	2.1%	0.0%	5.8%	1.8%
Others	7.7%	5.7%	24.5%	21.3%	9.1%	3.3%

[1]CA marginal electricity mix based on AB 1007 analysis
[2]NE U.S. marginal mix determined by setting GREET average NE U.S. residual oil and nuclear shares to zero and renormalizing the remaining fuel shares to 100% total.

Table 3.2. Adjusted Natural Gas-Fired Generation Efficiencies.

Generation Technology	**Adjusted Efficiency**	**GREET Default**
Natural gas-fired power plant (SCGT)	31.5%	33.1%
Natural gas-fired power plant (CCGT)	51.8%	53.0%

The analysis uses the Illinois SERC eGRID (Emissions & Generation Resource Integrated Database) region to represent the Midwest mix used for corn ethanol and soy biodiesel production. This region is a NERC (North American Electric Reliability Council) region and represents a significant part of the Midwest. The eGRID maintained by the U.S. EPA is a comprehensive inventory of electricity generation mixes, emission factors, fuel use, boiler, generator and integrated plant-level data for electric power systems (U.S. EPA 2007). The database provides average data by state, power company, parent company, eGRID sub-region, NERC region or the entire U.S. It contains data from 24 Federal databases from the EPA, EIA and FERC (Federal Regulation and Oversight of Energy). The latest data available (and shown above) is released as eGRID2007 Version 1.0, and contains 2005 data.

3.2 Conventional Fuels

3.2.1. Petroleum Fuel Parameters

The Northeast GREET Interface input sheet for NE petroleum fuels (conventional gasoline, RBOB, conventional diesel, ULSD and LPG) is shown below in Figure 3.1. The Northeast-specific input parameters are colored light red and as the figure shows, only the transport inputs and refinery energy shares have been modified. Other process parameters could also vary for the Northeast region. The Interface Tool enables convenient adjustment of key fuel pathway input parameters to assess different specific pathway scenarios, conduct sensitivity analysis or to facilitate new analyses when updated or improved data become available. The input sheet for NE petroleum fuels is shown as an example, and only the Northeast-specific input parameters for each fuel are shown in the following subsections.

The first component of the petroleum fuel cycle is the crude oil extraction efficiency. Here the GREET default is used as an input for the NE states. The GREET estimate is based on aggregate statistics for the U.S. These data vary considerably from year to year and the authors are not aware of significant efforts to relate operational data, type of oil extraction (primary, secondary, tertiary recovery) to crude oil extraction energy and the aggregate statistics used as life cycle inputs. In California, a lower crude oil extraction efficiency is assumed because a significant fraction of the state's production is based on thermally enhanced oil recovery.

As Figure 3.1 shows, the default NE petroleum input sheet uses the average U.S. electricity mix in GREET for crude extraction and assumes the NE average generation mix for refining. Note that the electricity fuel share inputs shown below the pull-down menus for electricity generation mix (for crude extraction and refining) are user inputs and are only input into GREET when "User Defined" is selected from the pull-down menu. The default "User Defined" electricity mix is NE marginal mix, which was discussed in Section 3.1.

Transportation distances are a key difference among regions in the U.S. The transport distances for crude oil and finished gasoline are based on NESCCAF's baseline petroleum supply report, summarized in Table 3.3 (based on NESCCAF's analysis of EPA data). The flow of petroleum products into the Northeast states could be analyzed further to achieve a slight improvement in transport distance accuracy for different finished fuels. For example, the GREET model could be run separately for each region with overall composite values developed for imported finished fuels and fuels produces in Northeast refineries.

Petroleum products are produced in refineries around the world with significant imports of finished product to the U.S. PADD (Petroleum Administration for Defense District) data can be used to determine weighted average crude flow shares and transport distances. PADD 1, which comprises the east coast (including the NE), leads the U.S. in imported refined product with 48% of finished gasoline imported from PADD 3 (Texas) by pipeline and 12% of finished gasoline imported from overseas locations.

The transport inputs in Figure 3.1 represent the composite of PADD 1 domestic and overseas imports. The transport distances for overseas import are based on the weighted average of crude oil imports by country based on EIA data; individual shipping distances by country of origin were determined using Eship (see Section 3.6). Domestic and Canadian imports of finished gasoline are assumed to be based on U.S. petroleum shares. However, some finished gasoline from PADD 3 may also be derived from overseas imports.

Crude Extraction

General	
Target year	2010
Share of oil sand products in crude oil blend	0.0%
Crude Recovery Efficiency and Fuel Shares	
Crude recovery efficiency	98.0%
Crude recovery fuel shares	
Crude Oil	1.0%
Residual Oil	1.0%
Diesel	15.0%
Gasoline	2.0%
Natural Gas	61.9%
Coal (Pet Coke)	0.0%
Electricity	19.0%
Refinery Still Gas	0.0%
Feed loss	0.1%
Electricity Generation Mix for Crude Recovery	
Electricity mix	N.E. Average
Fuel shares if electricity mix is "User Defined":	
Residual oil	0.0%
Natural gas	33.5%
Coal	51.6%
Nuclear	0.0%
Biomass	5.8%
Other (renewables)	9.1%

Crude Transport

Conventional Crude for Use in NE Refineries

Transport to U.S.	Share of Crude Oil	Share of Transport	Distance (mi)
Domestic Alaska	0.0%		
Ocean Tanker		100.0%	1,200
Pipeline		100.0%	4,000
California Production	0.0%		
Barge		5.0%	200
Pipeline		100.0%	50
Domestic US Other 48 States	48.0%		
Barge		0.0%	200
Pipeline		95.0%	1,613
Rail		5.0%	807
Imported Off Shore Countries	43.0%		
Ocean Tanker		100.0%	4,671
Pipeline		100.0%	178
Imported Canada and Mexico	9.0%		
Barge		0.0%	800
Pipeline		100.0%	2,530
Rail		0.0%	800

Figure 3.1. GREET Interface input sheet for NE petroleum-based fuels showing key fuel pathway parameters. Yellow values are input parameters, white values are calculated and Northeast-specific parameters are shown in light red.

Crude Refining

Crude Refining Energy and Fuel Shares

RBOB (%)	84.5%
Conventional Gasoline (%)	87.7%
ULSD (%)	86.7%
Conventional Diesel (%)	90.3%
LPG (%)	94.3%

Crude refining fuel shares

Crude Oil	0.0%
Residual Oil	1.9%
Diesel	0.0%
Gasoline	0.1%
Natural Gas	28.5%
Coal (Pet Coke)	22.4%
Electricity	4.1%
Refinery Still Gas	42.9%
Feed loss	0.1%

Electricity Generation Mix for Crude Refining

Electricity mix	N.E. Average

Fuel shares if electricity mix is "User Defined":

Residual oil	0.0%
Natural gas	33.5%
Coal	51.6%
Nuclear	0.0%
Biomass	5.8%
Other (renewables)	9.1%

Transport & Distribution

Transport to the U.S.

Conventional Gasoline

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	3.0%		
Ocean Tanker		100.0%	2,600
Imported: Canada	1.0%		
Pipeline		100.0%	750
Rail		0.0%	800

Reformulated Gasoline (RFG)

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	3.0%		
Ocean Tanker		100.0%	2,600
Imported: Canada	1.0%		
Pipeline		100.0%	750
Rail		0.0%	800

Figure 3.1. Interface input sheet for NE petroleum-based fuels showing key fuel pathway parameters (continued).

Conventional Diesel

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	4.0%		
Ocean Tanker		100.0%	1,300

Ultra-Low Sulfur Diesel (ULSD)

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	96.0%		
Imported: Caribbean countries	4.0%		
Ocean Tanker		100.0%	1,300

Liquefied Petroleum Gas (LPG)

	Share of Fuel	Share of Transport	Distance (mi)
Domestic	80.0%		
Imported: Caribbean countries	20.0%		
Ocean Tanker		100.0%	5,200

Transport and Distribution in the U.S. (All Fuels)

Transport to Bulk Terminal	Distance (mi)	Share of Total Fuel
Ocean Tanker	2,630	22.0%
Barge	200	0.0%
Pipeline	927	100.0%
Rail	0	0.0%
Heavy Duty Truck	50	0.0%
Distribution to Refueling Station		
Heavy Duty Truck	50	99.4%

TTW: Vehicle CH_4 and N_2O

Vehicle CH_4 and N_2O emissions	CG/RFG	CD/ULSD	LPG
Vehicle CH_4 emission rate (g/mi)	0.04	0.01	0.04
Vehicle N_2O emission rate (g/mi)	0.04	0.02	0.04
Vehicle total energy use (Btu/mi)	4,950	4,125	4,950

Figure 3.1. GREET Interface input sheet for NE petroleum-based fuels showing key fuel pathway parameters (concluded).

The analysis of imported gasoline and blendstocks in GREET is a simplistic representation as the total gasoline pool, which includes a mix of production resources, crude oil types, and refining. A more detailed analysis of all of the petroleum flows to the U.S., feedstocks, and products could provide a more accurate assessment of the attribution of crude oil resources to NE gasoline. Such an analysis would require the development of an attribution scheme for all petroleum products and a more extensive examination of the fate of petroleum products than was possible in this study.

Table 3.3. Petroleum Net Consumption in PADD 1 by Source (Millions of Gallons per year).

Source	Finished Gasoline	Light Distillates	Residual Fuel Oil	Jet Fuel	Crude Oil
Produced in PADD 1	21,349 (43%)	7499 (34%)	1503 (21%)	1396 (14%)	0
Transported from PADD 2	239 (<1%)	138 (<1%)	8 (<1%)	26 (<1%)	230 (1%)
Transported from PADD 3	23,863 (48%)	11,612 (52%)	690 (10%)	7514 (74%)	120 (<1%)
Transported from Canada	1426 (3%)	1409 (6%)	618 (9%)	131 (1%)	3253 (13%)
Other Import	5897 (12%)	3114 (14%)	4322 (61%)	1337 (13%)	20,531 (85%)
Transported out of PADD 1	(3256) (-7%)	(1626) (-7%)	(8) (<-1%)	(283) (-3%)	0
Net Consumption PADD 1	49,518 (100%)	22,146 (100%)	7133 (100%)	10,121 (100%)	24,134 (100%)
Consumption in NESCCAF Region (2006)	16,786	7272	2229	2395	-

2005/2006 Annual Average (Millions of Gallons); Source: NESCCAF analysis of EPA data.

Refinery efficiency and fuel shares are the GREET inputs that represent the energy inputs and emissions associated with oil refining. The refinery efficiency inputs are based on a combination of experience with refinery modeling and EIA data on refinery energy inputs. The EIA data is combined with a distribution of energy intensity for each refinery product to determine refinery efficiency. EIA reports fuel inputs to oil refineries which are the basis for the fuel shares input in GREET. Refineries also use hydrogen that is generated by adjacent hydrogen plants or hydrogen pipeline systems.

Table 3.4 summarizes ANL's analysis of the EIA data on refinery energy inputs. The energy inputs for refineries are combined with the natural gas associated with imported hydrogen to determine the fuel shares input for PADD 1 in Table 3.5. Several inputs are aggregated to represent the GREET fuel shares inputs. LPG is included with still gas, which is a low molecular weight hydrocarbon stream produced in the refinery. The carbon content per MJ and upstream energy inputs are comparable. Catalyst coke, other coke, and coal burned in the refinery are combined as coal. Imported hydrogen and purchased steam are included with natural gas as natural gas is the source of these energy inputs. Natural gas associated with hydrogen production represents and additional energy input outside of the refinery inputs reported by EIA. Thus, the total energy inputs in Table 3.5 sum to over 100%. These values are normalized to a total of 100% to represent GREET inputs.

Table 3.4. Share of Process Fuels Used in Oil Refining**.**

Process Fuel Shares	PADD1	U.S. Total	U.S. Total w. H2	GREET Category
LPG	0.5%	0.3%	0.3%	Still gas
Distillate Fuel Oil	0.1%	0.1%	0.1%	Diesel
Residual Fuel Oil	2.2%	0.4%	0.3%	Residual Oil
Still Gas	48.6%	48.4%	39.3%	Still gas
Marketable Petroleum Coke	0.0%	0.1%	0.1%	Coal
Catalyst Petroleum Coke	25.3%	17.6%	14.2%	Coal
Natural Gas (million cubic feet)	14.2%	23.2%	37.8%	Natural Gas
Coal (thousand short tons)	0.3%	0.0%	0.0%	Coal
Purchased Electricity (million kWh)	4.7%	4.3%	3.5%	Electricity
Purchased Steam (million lb)	4.1%	4.3%	3.5%	Still gas
Other Products (pentanes plus, other HCs)	0.1%	1.2%	1.0%	Gasoline

Source: ANL analysis of 2006 EIA Refinery Capacity Report
Note: Natural gas in PADD1 would be 23.1% including hydrogen

In practice, refinery energy inputs can vary significantly among U.S. refineries. The California AB1007 analysis examined the energy inputs for gasoline refining reformulated gasoline and estimated a refinery efficiency of 84.5% for CARBOB, compared with the 87.2% assumed in the GREET model. The JEC European well to wheels study estimates considerably different energy inputs for marginal gasoline production. For the purposes of implementing LCFS calculations for the Northeast states, a reasonably accurate default value could serve as the baseline for petroleum fuels. Alternatively, individual gasoline providers could calculate their aggregate GWI for gasoline production. California has avoided this approach for now, choosing to focus the LCFS on alternative fuels.

Table 3.5. Calculation of Fuel Shares GREET Input.

Fuel	PADD 1 Refinery and H_2 Energy	PADD 1 GREET Input	Default GREET Input for U.S.
Crude Oil	0.0%	0.0%	0%
Residual Oil	2.2%	1.9%	3%
Diesel	0.1%	0.0%	0%
Gasoline	0.1%	0.1%	0%
Natural Gas + Hydrogen	32.6%	28.5%	30%
Coal (Pet Coke)	25.6%	22.4%	13%
Electricity	4.7%	4.1%	4%
Refinery Still Gas	49.0%	42.9%	50%
Total	114.3%	100.0%	100%

3.2.2. Natural Gas Parameters

A Northeast marginal electricity mix is assumed for the CNG (compressed natural gas) pathway because natural gas is considered an alternative transportation fuel; default GREET 1.8b input parameters are used for non-electricity inputs. The CNG pathway assumes North American natural gas feedstock and an electric compressor for natural gas compression.

The LNG (liquefied natural gas) pathway uses all GREET default values, non-North American natural gas and a U.S. electricity mix (see the CNG and LNG tabs of the Northeast GREET

Interface file to review key input parameters). Imported LNG represents a significant source of gas supply with 22% of supply in the Northeast and 3% in the U.S. Thus, both a share of CNG and electric power could be considered derived from imported LNG. Determining the marginal source of natural gas would require further analysis. For the purposes of this study, the GWI for CNG and electric power was calculated for 100% North American (NA) natural gas and 100% remote natural gas (RNG). A composite value weighted with 22% RNG is also calculated. Note that GREET is not configured to input a mix of natural gas resources so these values are based on separate GREET runs.

3.3 Imported Biofuels

3.3.1. Corn Ethanol Parameters

The corn ethanol pathway assumes Midwest corn is transported to the Northeast. Corn ethanol is assumed to use the Illinois SERC (Southeastern Electric Reliability Council) electricity mix. The fuel pathway uses GREET default input parameters for all inputs except for co-product inputs and ethanol transport—see Table 3.6 below. The ethanol transport mode shares and distances for transporting ethanol to the Northeast are shown in Table 3.7.

Table 3.6. Adjusted Corn Ethanol Input Parameters**.** Yield Values on an Anhydrous Ethanol Basis.

Inputs	Revised Parameters	GREET Default
Ethanol Yield (gal/bu)	2.67	2.72
DGS yield (lb/gal)	6.72	5.34
Feed corn/DDGS displacement ratio	0.5	1.077
Soybean meal/DDGS displacement ratio	0.5	0.823

Ethanol yield and co-product inputs based on ARB's documentation of ethanol pathways. Input values are still under review. GREET default co-product credit reflects growth in corn crop resulting in DDGS plus stover production, which in combination displace feed corn and SBM.

Table 3.7. Corn Ethanol Transport Input Parameters.

Transport Leg	Revised Distance (mi)	Revised Share (%)
Transport to Bulk Terminal		
Barge	0	0.0%
Pipeline	0	0.0%
Rail	800	100.0%
Heavy duty truck	50	80.0%
Ethanol Distribution		
Heavy duty truck to fuel station (mi)	50	100.0%

3.3.2. Biodiesel and Renewable Diesel Parameters

Biodiesel uses GREET default input parameters for all steps of the fuel pathway except for soyoil transport and biodiesel transport. The Illinois SERC region electricity mix is assumed for the pathway. GREET assumes that soyoil extraction and oil transesterification take place in the facility, which is often not the case. Since GREET is not configured for separate transport modes for soy oil and biodiesel, we have created inputs for soy oil transport in the Northeast GREET Interface BD sheet that the interface combines in a weighted average with the biodiesel transport and distribution inputs for input into GREET; soy oil is transported via rail. The relevant transport parameters are shown below in Table 3.8.

Table 3.8. Soy Oil and Biodiesel Transport Input Parameters.

Transport Leg	Revised Distance (mi)	Revised Share (%)
Soy Oil to Processing Plant		
Rail	800	100.0%
Biodiesel Transport		
Barge	520	71.0%
Pipeline	0	0.0%
Rail	800	0.0%
Heavy duty truck	50	80.0%
Biodiesel Distribution		
Heavy duty truck to fuel station (mi)	50	100.0%

3.4 Northeast Biomass Parameters

Woody biomass is considered trees, shrubs, bushes or by-products of these woody plants and includes waste streams that accumulate to create a hazard or disposal problem and dedicated energy crops such as farmed wood. The Northeast, where forested land is primarily in private hands, possesses significant woody biomass resources that can be converted primarily to ethanol (or other fuels). Every year one million tons of biomass naturally accumulates on the forest floor in the 6.1 million acre Adirondack Forest in New York State. Approximately 2 million tons of woodchips from the privately held stands of the Adirondacks enter the low grade wood market each year (for biofuel or paper pulp)[7].

Historically, woody biomass has been a by-product of timber harvests or forest thinning (which is routinely done to improve 'the stand' of timber and then classified as firewood or pulp for paper mills. As the energy market demands this biomass, the market is changing from a commodity based structure where all pulpwood is treated virtually the same- to a differentiated market with many factors such as tree species, moisture content, size of the tree or stand and part of the tree harvested, etc.

Section 3.5 discusses biomass-to-heating pellets pathways. The main process technologies for fuel conversion to ethanol are fermentation and gasification. The Northeast Interface Tool is set up to model ethanol from forestry residue via gasification and fermentation and from farmed trees via fermentation. These three fuel pathways use the Northeast marginal electricity mix and GREET default input values, except for ethanol transport inputs and forestry residue transport distance. Table 3.9 below shows the Northeast-specific transport inputs for forestry residue and ethanol. The ethanol transport inputs are the same for farmed trees ethanol and the feedstock transport distance is 40 miles.

[7] Retrieved from www.smallwood.com *New York: DE Explores Woody Biomass as Alternative Energy Source*. September 2007.

Table 3.9. Forestry Residue Transport Input Parameters.

Transport Leg	Revised Distance (mi)	Revised Share (%)
Forestry Residue		
Heavy duty truck	60	100.0%
Transport to Bulk Terminal		
Barge	520	0.0%
Pipeline	600	0.0%
Rail	800	50.0%
Heavy duty truck	80	70.0%
Ethanol Distribution		
Heavy duty truck to fuel station (mi)	30	100.0%

Moisture content (MC) is an important property of wood that determines transport, processing and combustion efficiencies. Moisture content is reported on both a dry basis and wet basis. The wet basis, used primarily by engineers and scientists, is defined as the water mass (mass of water removed to yield bone-dry wood) divided by the green (initial) wood mass. The dry basis is useful for consideration of lumber properties and is used by foresters and wood technologists. This analysis only uses moisture content inputs on a wet basis, which is the typical approach for reporting percentage values, and the moisture content inputs discussed next are presented on a wet basis.

The default moisture content inputs in GREET (20%) for forest residue and farmed trees (25%) are much lower than the actual moisture content of harvested woody biomass. On average, harvested biomass has an MC of 50% (100 lb biomass = 50 lb water + 50 lb wood). Purchased green biomass moisture content varies 30 - 55% (% delivered weight), which impacts life cycle inputs and results (Maker 2004). Table 3.10 below presents the relevant MC values. Moisture content can affect many aspects of the fuel cycle including dry cargo capacity, combustion efficiency, chipping energy, gasification yield, water consumption, and others. The GREET model is not configured to adjust all of the pathway parameters for feedstock moisture but GREET accounts for moisture content in determining the transport truck dry cargo capacity and is used to adjust the transport results per ton of biomass transported to a dry wood basis, and finally to a fuel energy basis (g/mmBtu) for fuel production. In the context of GREET model inputs, the most significant effect would involve transport efficiency. Moisture content is described more in the context of transport inputs in Section 3.5.2.

Table 3.10. Moisture Contents (Wet Basis) for Woody Biomass

Feedstock	Moisture Content (Wet Basis)
Farmed Trees (GREET default)	25%
Forestry Residue (GREET default)	20%
Purchased Green Biomass	30 – 55%
Sawdust	35 – 40%

3.5 Wood Pellets

3.5.1. Logging and Feedstock Collection

The team reviewed the energy inputs for the collection and processing of forestry feedstocks. Lumber harvesting activities typically include harvesting the trees with harvesting equipment (chainsaws or mechanical felling machines) and moving the logs to a central location (skidding). The equipment used here runs on diesel predominantly. Gasoline powered chain saws are not typically used in Northeast logging operations because commercial scale logging equipment provides greater productivity and safety than traditional methods in this heavily forested region. The portion of the tree that is converted to biomass feedstock is chipped on site and then transported for biomass energy or pulp/paper operations.

Innovative Natural Resource Solutions LLC (INRS) examined the energy inputs required for biomass production (Kingsley 2008). Table 3.11 provides an estimate of the diesel energy inputs for commercial logging operations and forest residue collection based on surveys of 5 major contractors operating in the Northeast states. The energy input in Btu of diesel per ton of biomass is presented at the bottom of the table, based on the fuel use in gallons. The level of activity was estimated to be similar for large scale logging and selective forest thinning, as the size of the tree parts are relatively large diameters (3 to 6 inches).

Estimates of the energy inputs to handle lumber mill waste are also indicated. The portions of the log that are not converted to lumber still require handling and chipping and a preliminary estimate of the energy requirements is the same as that for forest residue. Of course the alternative fate of the lumber mill waste could also be considered. Mill residues can be stored in debris piles for many years, and even this activity requires energy. The INRS survey found that most of the wood processing used diesel fuel.

Table 3.11. Diesel Inputs for Forestry and Estimates for Lumber Mill Operations (Kingsley, 2008).

Activity	Forest Residue	Lumber Mill Waste	Units
Felling & Skidding	0.6	0	gal/green ton
Landing, yarding, sorting, handling	0.25	0.25	gal/green ton
Chipping	0.42	0.42	gal/green ton
Total	1.27	0.67	gal/green ton
	2.31	1.22	gal/dry ton
	294,326	155,274	Btu/dry ton

The energy requirements for processing forest residue correspond to about half of the GREET default value and are slightly higher than the default value for harvesting energy crop trees

(234,770 Btu/dry ton). Since the INRS data is based on a survey of actual operating data in the Northeast region, these estimates seem appropriate as inputs for the life cycle analysis of forest residues.

The appropriate energy inputs for the life cycle analysis are 100% diesel for the feedstock harvesting and collection and diesel fuel for transport. New pellet mills tend to be equipped with electric powered motors for operating the mechanical equipment. Yard equipment would be diesel fueled, so the energy inputs for pelletizing operations would be a combination of diesel fuel and electricity.

3.5.2. Wood Chips and Pellets Transport Parameters

Delivery of wood chips involves trucks loaded to about 27 tons of chips with 45-50% moisture content (wet basis), or approximately 13.5 dry tons. Default GREET calculations are based on a 17 ton load with 20% MC, equivalent to approximately 13.6 dry tons, indicating that the dry weight capacity is consistent with industry practice, but the wood chip transport results in GREET are too low due to the small biomass MC inputs.

Transport of chipped biomass was estimated using a 27 ton truck moving chips with 50% moisture content (wet basis) and yielded a similar energy intensity input (Btu/dry ton-mi) as the GREET default inputs. The truck fuel economy of 5 mpg is consistent with a fully loaded 40 ton gross vehicle weight truck. Table 3.12 below presents direct input parameters (upper segment of table) and calculated parameters (lower part of table) for all transport scenarios relevant to the wood pellet pathway. Heavy duty trucks are used to transport wood chips which are processed into pellets and a processing facility, and either transported a long distance (B.C. scenario) by rail to a retailer or transported a shorter distance (110 mi) by heavy duty diesel truck to a retailer. A 1 ton family size SUV is assumed for the final transport leg to the point of use. Pellet production and input parameters are discussed next.

Table 3.12. Wood Chip Transport (Woody Feedstock) Parameters.

Parameter	Heavy Duty Truck	Heavy Duty Truck	Heavy Duty Truck	Heavy Duty Truck	Rail	SUV
Fuel	Diesel	Diesel	Diesel	Diesel	Diesel	RFG
Cargo	Forestry Res. Chips	Sawdust	Farmed Trees Chips	40 Lb Pellet Bags	40 Lb Pellet Bags	40 Lb Pellet Bags
Cargo Capacity (tons)	27	27	27	27		1
MC (% of total wt)	50.0%	40.0%	50.0%	7.0%	7.0%	7.0%
Fuel Economy (mi/gal)	5	5	5	5		16.0
Fuel Energy Content (Btu/gal)	128,450	128,450	128,450	128,450	128,450	116,090
Cargo Energy Density (Btu/ton)	16,811,000	16,399,417	19,546,300	16,399,417	16,399,417	16,399,417
Energy Consumption To Dest. (Btu/mi)	25,690	25,690	25,690	25,690		7,256
Energy Consumption Return Trip (Btu/mi)	25,690	25,690	25,690	25,690		7,256
Energy Intensity To Dest. (Btu/ton-mile)	951	951	951	951	370	7,256
Energy Intensity Return Trip (Btu/ton-mile)	951	951	951	951		7,256
One-way Transport Distance (mi)	30	30	30	110	1,100	30
WTT Fuel Energy (Btu/Btu)	0.161	0.161	0.161	0.161	0.161	0.207
Total Energy (Btu/ton)	66,289	66,289	66,289	243,060	472,591	525,539
Specific Energy (Btu/Btu)	0.004	0.004	0.003	0.015	0.029	0.032

3.5.3. Wood Pellet Feedstocks, Production and Life Cycle Analysis

Wood pellets for home heating produced from lumber mill residue (sawdust), forestry residue and farmed trees were incorporated into the GREET interface using life cycle inventory data generated by GREET. Fuel pellets are primarily produced from saw mill residue today. However, several pellet mills have recently been built to convert harvested wood into fuel pellets. Pellets can be produced from any woody feedstock in principle and Table 3.13 below briefly summarizes potential woody feedstocks, issues associated with life cycle analysis of these materials and alternative uses. Certain biomass feedstocks have favorable processing characteristics and different feedstocks yield pellet products of varying quality. This report does not assess the viability of possible feedstocks other than forestry residue, farmed trees and sawdust (lumber mill residue).

Table 3.13. Potential Woody Biomass Resources, Life Cycle Issues and Alternative Uses.

<table>
<tr><th>Biomass Resource</th><th>Feedstock Type</th><th>Life Cycle Analysis Issues</th><th>Alternative Uses</th></tr>
<tr><td>Forestry Residue (Light Thinning)</td><td>Tree tops, undersized lumber</td><td rowspan="6">• Alternative fates: decomposition, fire

• Forest thinning reduces fire risk

• Life cycle impact heavily dependent on management practices

• Changes in carbon deposition and soil carbon (net carbon storage)

• Collection impacts (logging roads, diesel use, etc.)

• Displacement of Fossil Fuels

• Biomass combustion emissions considered GHG neutral, but include methane and nitrous oxide</td><td rowspan="6">Wood Form (Residue and Roundwood)
• Lumber, fuel wood, posts, mulch, pulp, composites, animal bedding
• Heating pellets

Chemically Converted Form
• Chemical pulp, C5 and C6 sugar solutions, liquid fuels

Biologically Converted Form
• Fermentation products, liquid fuels, composted litter

Power, Heat, & Steam Generation
• Direct combustion, or gasification and combustion</td></tr>
<tr><td>Roundwood (Actively Managed Forest)</td><td>Segment of round cut tree</td></tr>
<tr><td>Diseased or Decimated Wood</td><td>Unmarketable Waste Biomass</td></tr>
<tr><td>New Growth (Conversion of Pasture to Forest or Managed New Growth)</td><td>Energy Crop</td></tr>
<tr><td>Urban Wood Waste</td><td>Wood Chips from Recycling Facility</td></tr>
<tr><td>Sawdust</td><td>Lumber Mill Residue</td></tr>
</table>

Life cycle analyses typically assume that feedstock component of biomass resources are carbon neutral. The cycle of carbon in forests is a system of stocks (eg. pools) with carbon flows between them. Biogenic carbon, recently removed from the atmosphere through photosynthesis, and used as fuel (solid, liquid or gaseous) returns the carbon to the atmosphere. However, this assessment does not fully consider the reference case for the biomass. What would happen absent a conversion to biomass? The calculation of net carbon storage would be comparable to the land use conversion analysis applied to other biofuels. Selectively harvesting wood from mature forests offers the opportunity for carbon neutrality of the feedstock because faster growing new trees replace mature trees. Carbon storage, via the additional displacement of fossil fuel use with 'forest carbon' use, might even be accelerated with carefully managed forests. A shift in tree species, harvesting practices, and other parameters would affect the net carbon impact on the forest and requires further examination.

Forest soils store at least as much carbon as the biomass in the forest, and the fate of the carbon depends several factors, including soil characteristics, climate and forest management intensity. Deforestation of primary forests reduces the stored carbon in forest biomass and soil but sustainably managed forests can achieve a dynamic carbon pool equilibrium, reflecting harvesting cycles. Significant reductions is biomass residues in forests can lead to reductions in soil carbon, since there is less material on the forest floor to incorporate into the soil. Net carbon storage in the system depends on the changes in the soil carbon sink and forest biomass.

The inputs for forest residue used in the GREET model require further examination because all of the scenarios for forest residue are site specific. Energy inputs would include harvesting, removal, chipping, and transport equipment with the primary energy inputs being diesel fuel and gasoline.

The industry standard form of wood for the pulp and paper industry is referred to as a pulp chip. Portions of the tree that are used for chip production can be processed in the field or at interim chipping locations. Pulp chips are also potential feedstock for cellulose based ethanol production and biomass power plants.

The calculations in the GREET model for the farmed tree pathway provide the basis for determining the life cycle energy for pulp chips. This pathway allows inputs for tree farming, harvesting, and transport. In the case of forest residue, the fertilizer inputs are zero. In the case of lumber mill residue (sawdust), the farming inputs are assumed to be zero and only transportation energy is counted towards feedstock production. The fuel pellet life cycle includes the following steps:

- Feedstock production and transport (GREET calculation)
- Pellet mill operation
    - Chip grinding (zero for sawdust)
    - Pellet mill operation
    - Yard equipment
- Wholesale transport by rail and truck
- Home delivery

A pellet plant requires a forklift/tractor to move feedstock, in addition to dyes, extruders, feeders, grinders, etc. On average, diesel forklifts use approximately 12 gallons of fuel per day working 4 hours/day (CEC 2007). For comparison, diesel forestry equipment consumes 24 gallons/day. A pellet plant producing 120,000 tons pellets/yr must have equipment capable of moving approximately 120-144 tons of woody feedstock per hour. This analysis assumed 4 tractors each using 12 gallons/day to handle this load, each moving 30.7 tons per hour. Dividing the energy content of the fuel consumed by the dry weight throughput yields 20,165 Btu/dry ton. This input is used with WTT result for diesel and equipment emission factors from GREET to calculate the life cycle emissions of the plant yard tractor.

The total electricity requirement for pelletizing is 120 kWh/ton of pellets using pulp chips (0.25" minus size) and saw dust. An additional 30 kWh/ton is required to grind unchipped forestry residue and farmed trees down to the 0.25" minus size for pelletizing. The scenarios considered in this analysis assume biomass is chipped onsite in a central location near forest felling or tree cultivation, and therefore the chipping energy is diesel powered and included in the feedstock collection energy input. The GREET Northeast average electricity mix was assumed for pellet plant electricity requirements, since pellet production is an established, ongoing industry.

For pellet transport, the default truck distance reflects transport from Vermont to Maine and the rail distance represents transport from British Columbia to Vermont, as a case examination of the significant imports of B.C. pellets to Northeast in recent years. By setting rail mode share to 0, model inputs reflect NE-produced feedstocks. An SUV carrying 1.0 ton, or 50 bags of pellets, is assumed for pellet transport from a retailer to a residential home.

After transport, pellets are combusted in a pellet burning appliance (stove) under carefully controlled conditions. Wood pellets are inherently drier than larger wood because of their small size and higher density and therefore contain a higher heating value. Home pellet appliances burn small, 3/8–1 inch (100–254 mm)-long pellets that resemble rabbit feed in appearance. Pellets can be made from compacted sawdust, wood chips, bark, agricultural crop waste, waste paper, and other organic materials. Some stoves can also burn nutshells, corn kernels, and small wood chips. Default emission factors for pellet stoves are based on biomass combustion emission factors from GREET.

3.6 Transportation and Distribution

3.6.1. Northeast Specific Parameters

Average Northeast parameters are needed for this analysis, including average transport distances and transport mode shares, petroleum resource types and regional-specific emission factors. GREET does not distinguish emissions by region or crude type and this analysis is data limited, due to the cost and difficulty in collecting regional data for analysis.

Biofuel transport input parameters include mode share and transport distance for feedstock and biofuel transport. These distances are well known for feedstock transport and biofuel transport distances can be estimated using electronic maps and measurement tools. Petroleum flows are more complicated, since crude is transported from several different sources, refined with several other crudes, and then blended with petroleum fuels made in other refineries. Calculating average Northeast transport shares and distances can be accomplished by aggregating U.S., Canadian, and offshore imports to the Northeast. Transport is accomplished by ocean tanker for imported offshore import and by barge, pipeline and rail for all other categories. These regions also correspond to GREET input categories, and inputs correspond to the share of total petroleum, transport mode share and distance.

3.6.2. Transport Distance Data Sources

As discussed in Section 3.2, crude oil and finished fuel import data to determine the Northeast mix required determining the source of the crude oil. Petroleum consumption data for PADD1 provided by NESCCAF was used to determine transport mode shares. EIA import data by PADD (the Northeast is in PADD 1) are summarized in Table 3.14 by PADD and regarding total volume of imports (volume data are found on the Energy Information Administration (EIA) website) (EIA 2008). This data is presented only to provide context for the PADD 1 consumption values.   Import volume data is used to estimate import crude and finished fuel volumes, given the known petroleum sources. Interestingly, imports of finished fuels in PADD 1 represent a much higher fraction of total gasoline consumption than other PADDs. Further analysis of the energy inputs as well as transportation mode and capacity would be of interest.

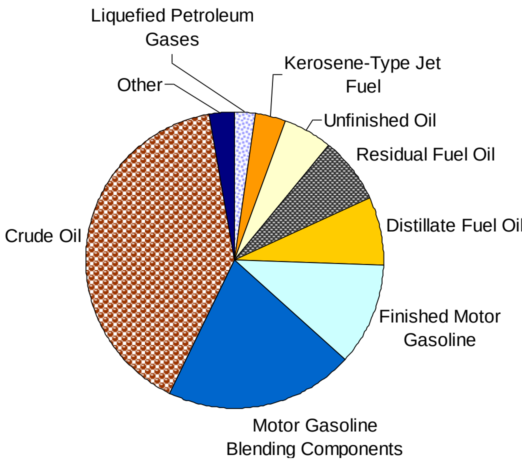

Figure 3.2. PADD 1 imports (Northeast Region).

Table 3.14. Imported Fuel Volumes by PADD (Millions of Gallons/Year) (EIA 2008).

Product	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Crude Oil	17843	17870	67333	3289	13678
Motor Gasoline Blending Components	7524	6	719	0	750
Finished Motor Gasoline	4116	17	334	0	404
Distillate Fuel Oil	2784	73	292	101	372
Residual Fuel Oil	2564	83	1389	0	412
Unfinished Oil	2028	45	5672	0	833
Kerosene-Type Jet Fuel	1169				
Liquefied Petroleum Gases	827				
Asphalt and Road Oils	309				
Oxygenates-Fuel Ethanol	249				
Petroleum Coke	239				
Naphtha for Petrochem. Feedstock Use	51				
Special Naphthas	51				
Kerosene	36				
Lubricants	32				
Waxes	7				
Finished Aviation Gasoline	2				

The ocean tanker distances are based on an online distance, fuel and cost calculator for ship voyages (see Figure 3.3 below) (Eship 2008). Pipeline and rail distances have been generated through Google's distance measurement tool (Google 2008).

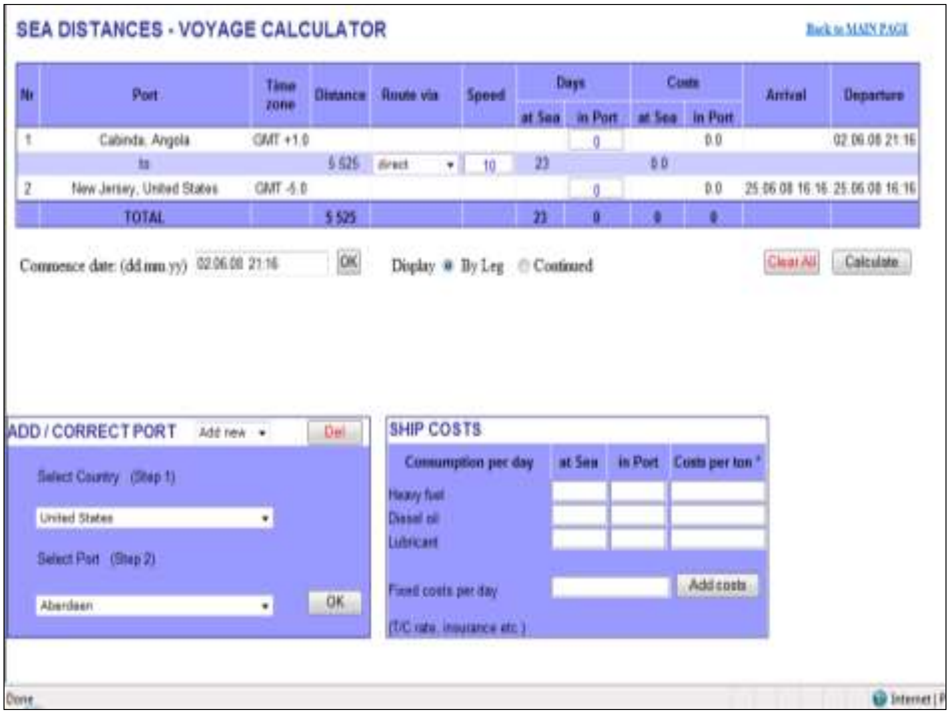

Figure 3.3. Screen shot of Eship online calculator for estimating ocean tanker distances (Eship 2008).

The import volumes and transport distances by country of origin were used to calculate weighted transport distances. Marine vessel transport distances and crude oil import volumes are summarized in Figure 3.4.

3.7 Land Use Conversion for Biofuels

Land-use change (LUC) is an important element of a biofuel's life cycle impact, including the direct emissions associated land conversion to agricultural fields and indirect emissions associated with economic impacts induced by the land-use change. Direct emissions are associated with the clearing of land and preparation to grow crops and include changes in soil carbon and above ground flora. All of the above ground carbon and a significant fraction of soil carbon are converted to CO_2 when land is converted to agricultural production. The second category, indirect or market-mediated LUC occurs when the production of biofuels displaces some other land use, with effects potentially cascading through international markets, resulting in the same type of LUC as for the direct effects. These effects are extremely difficult to predict or measure with any accuracy, and are highly uncertain.

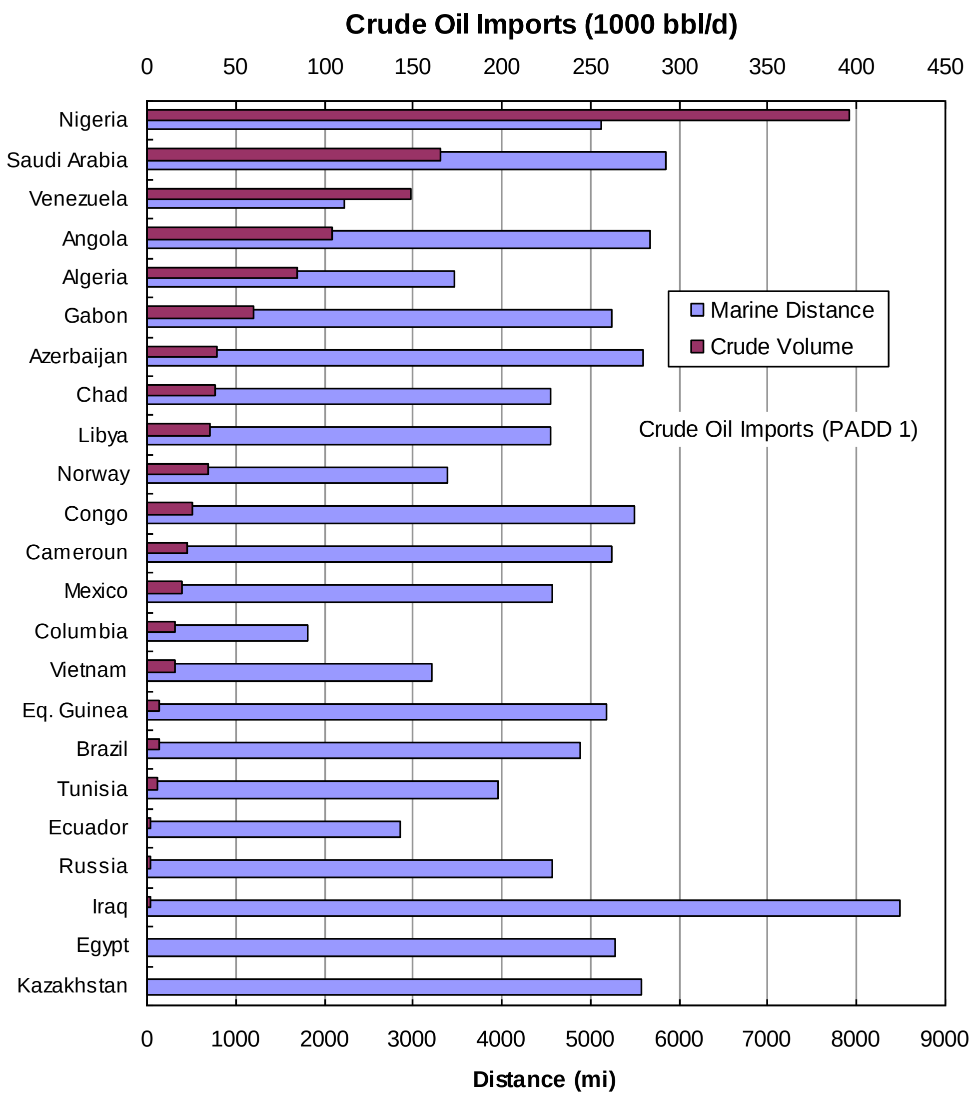

Figure 3.4. Marine transport distances and crude oil volumes to PADD 1 (Source: 2007 EIA data).

LUC is being modeled as an economic phenomenon predicted by economic (partial or general) equilibrium models that represent food, fuel, feed, fiber, and livestock markets and their numerous interactions and feedbacks. Results from large-scale economic models, however, depend on a wide range of exogenous variables, such as growth rates, exchange rates, tax policies, and subsidies for dozens of countries.

EPA is using the FASOM and FAPRI models to estimate the changes in crop acreage in domestic and internationals market and to combine these results with estimates of soil carbon and nitrogen flows based on the DAYCENT model. The GTAP model is being used by UC Berkeley and Purdue University to evaluate land use conversion impacts of biofuel production expansion. This combined effort is used in support of the California Low Carbon Fuel Standard.

Different ecosystem types store different quantities of carbon in the soil and in the above-ground biomass. Conversion of land between ecosystem types results in a new equilibrium carbon storage level over time, with associated storage or release of carbon.

The LUC effect is an input to the GREET model for corn, woody biomass, and herbaceous biomass crops. Even though crop yields for soybean production are one fourth those of corn, the LUC impact for soybean biodiesel is ignored in the current version of GREET. GREET default values include entries for corn ethanol that correspond to about 1 g/MJ of corn ethanol. These values are based on a decades old analysis and may not include the effect of international LUC. The input values for cellulosic energy crops reflect a negative LUC (or net carbon storage). These inputs reflect a build up of root material in the land. Again, the indirect LUC values need to be reexamined for cellulose feedstocks.

As the analysis is revised, data that reflect LUC can serve as GREET inputs. The scope of the in LUC inputs needs to be carefully examined to assure that they reflect only the emissions related to land conversion and not additional co-product impacts (such as avoided farming energy) that might be included in the LUC modeling systems as GREET calculates the process energy impacts of co-products.

4 Analysis Tools

An LCFS requires dynamic tools that facilitate process specific life cycle analysis, based on pathway configurations specific to individual processes. Life Cycle Associates developed a spreadsheet-based Interface Tool that runs on top of GREET and operates the model (see next section). As discussed earlier in this report, the GREET model is an excellent source of life cycle data, including feedstock inputs, process data, allocation and emission factors.

4.1 GREET Interface Tool

The GREET Interface Tool is an Excel spreadsheet organized with each tab containing a fuel pathway for simulation, including all of the fuels shown in Table 2.3. The tool file is opened after the GREET spreadsheet has been opened and is used exclusively to control GREET thereafter. Each fuel input tab allows the user to specify the 70 + key inputs for the selected fuel pathway, insert these parameters in the model, run GREET and extract the results. A separate User Manual documents the use of the interface file. A tab labeled “Defaults” contains the average default values for all pathways. These default values include both GREET default values (yellow values) and default Northeast and CA (CARBOB and CA ULSD) parameters (light red).

5 Results and Discussion

5.1 Interface Tool

The Interface Tool file provided to NESCCAF provides an easy way to explore the key fuel pathway inputs quickly and effectively in one place and to investigate the sensitivity of model results to individual parameters. NESCCAF can flexibly calculate life cycle energy and emissions for thousands of potential fuel pathway configurations using combinations of pathway options and resource and electricity mixes. As emission values associated with land-use conversion become available, they can easily be incorporated into the GREET Interface input sheets.

The Interface Tool allows for a calculation approach that is consistent with the CA LCFS but with regionally specific parameters. The key factors that would differ can be investigated by running the tool with different assumptions. Some of the key parameters are summarized below:

- Electricity resource mix
- Crude oil extraction efficiency (CA has significant tertiary oil recovery)
- Refinery efficiency (This value should depend on the refinery configuration and detailed modeling of refinery energy flows and crude oil types, and gasoline specifications would affect this input)
- Refinery fuel shares (EIA data for PADD 1 shows for FCC coke combustion)
- Transport distances for all feedstocks and fuels
- Process specific data for fuel suppliers

5.2 Comparison of GWI for Northeast and California fuels

All of the GWI results for Northeast fuels were determined using the Northeast GREET Interface. In general, the GWI for fuels used in the Northeast are slightly higher than CA fuels, due primarily to the Northeast electricity mix, differences in transportation distances and mode shares and differences in crude mix for petroleum pathways. Table 5.1 below shows the results for fuels used in both regions. These calculations use average inputs for fuels used in the production of the given fuel; for example, the RBOB value uses default inputs for calculating diesel, which is used to make RBOB. Greater transport distances for Midwest corn ethanol and biodiesel used in California result in a larger GWI than their Northeast counterparts.

Table 5.1. GWI for Northeast and California Fuels (g/MJ).

	Northeast			CA
Fuel	**NA NG**	**RNG**	**22% RNG**	
ULSD	93.2	--	--	96.0
(CA)RBOB	96.8	--	--	96.1
Corn EtOH	71.2	--	--	72.1
Forestry Residue Fermentation EtOH	-4.4	--	--	-
Forestry Residue Gasification EtOH	9.9	--	--	-
Farmed Trees Fermentation EtOH	-13.3	--	--	-
Biodiesel	35.1	--	--	35.7
CNG	73.1	83.3	75.3	70.9
Electricity (average mix) NA NG	168.2	179.6	176.3	131.2

Northeast states have significant forestry and lumber resources, and as Table 5.1 shows, ethanol fuel made from biomass resources has significantly lower GWI (-13.3 to 9.9 g/MJ) than corn ethanol (71.2 g/MJ) or petroleum fuels (93.2 – 96.8 g/MJ). The share of available biomass that can be feasibly converted to pellets can achieve low life cycle emissions (11.0 – 18.0 g/MJ pellet). It should be noted that a standard methodology for dealing with feedstocks that are waste products has not yet been established and it's unclear what to assume as the baseline fate for a given waste stream. For example, the fate of forestry residue could be sequestration underground (incorporation in soil), rotting on the forest floor, fire etc. Each of these possible feedstock baseline scenarios has a different emission profile.

The GWI of fuels used in the Northeast are on par with California fuels, but slightly higher for some fuels and lower for others, due to the differences in crude imports, electricity mix and transport characteristics. The Northeast average electricity mix yields 30% higher fuel cycle greenhouse emissions than the CA average mix, and 23% lower emissions than the U.S. average electricity mix. An electricity-intensive process using the average Northeast mix will yield lower emissions than the same process using the U.S. average electricity mix, due to the lower coal process fuel share. Under an LFCS, renewable electricity providers (or other electricity mixes) could supply electricity for fuel production, resulting in different results for power generation.

The Northeast has abundant biomass resources, such as forestry residues and various woody waste streams including bark, sawdust, wood scraps and chips that can be advantageously converted to energy, fuel or heat. Only a share of the total potential biomass available is actually viable for fuel or pellet production. Technology is quickly developing to convert cellulosic materials to ethanol and other liquid fuels economically and the projected GWI for these fuels are very competitive—significantly below conventional and other alternative fuels.

Results for wood pellets are shown below in Table 5.2. This table presents the GWI results in g/MJ pellet, although the Interface Tool calculates results in g/ton pellets and g/MJ heat provided (based on furnace efficiency) as well. As the results show, wood pellets from forestry residue are approximately 5.3 g/MJ higher than pellets made from sawdust, and all wood pellets result in significantly lower life cycle GHG emissions than fossil fuels. The GWIs for pellets transported from B.C. are slightly higher but similar than pellets made in the NE. Note that the results are very sensitive to the water content of the woody feedstock and finished pellets and to the capacity of the consumer vehicle used to transport pellets to their point of use. A 1 ton capacity is assumed for the consumer vehicle as a baseline, and changing this input significantly impacts the results. These tables present the regional fuel results for specific fuels assuming average life cycle inputs for external fuel pathways.

Table 5.2. GWI for Wood Pellets, NG and #2 HHO (Home Heating Oil). Pellets Transported from Vermont to Maine for Use.

Pellet Feedstock	**Pellet Transport**	**GWI (g/MJ pellet)**
Forestry Residue	Vermont to Maine	18.0*
Lumber Mill Residue	Vermont to Maine	13.6
Farmed Trees	Vermont to Maine	15.9
Forestry Residue	B.C. to Maine	14.9
Lumber Mill Residue	B.C. to Maine	11.0
Farmed Trees	B.C. to Maine	12.9
Natural Gas	N/A	73.1
Home Heating Oil	N/A	94.7

*Slightly lower forestry residue result (15.9 g/MJ) derived when lower (294,326 Btu/dry ton, presented in Table 3.10) is used as the collection energy.

The values in Table 5.2 represent large pellet production operations (120,000 tons/yr) and the results could vary considerably based on the scales of specific wood harvesting and pelletizing operations. Other site-specific factors, such as regional geography, forest density, wood quality and transport distances (feedstock and pellets) will cause an individual producer's GWI to vary from the average value. The GWI for pellets will also vary if electric equipment is used to harvest or move feedstock rather than diesel equipment. Finally, the life cycle analysis of any product must consider the alternative fate of the feedstock used to make that product and such data is not currently available. A standard life cycle methodology for addressing waste stream feedstocks has yet to be developed and is necessary for comparing the net GWI for various products made from waste stream and conventional feedstocks.

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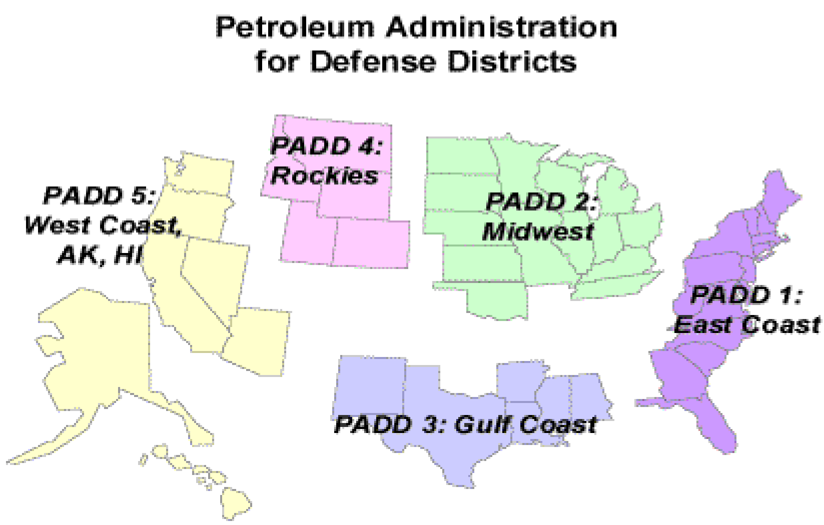
Appendix C: Northeast Fuel Supply and Distribution Network

Appendix C: Northeast Fuel Supply and Distribution Network

Five regions have been established by the U.S. government for the purpose of tracking petroleum product sales, consumption, production, and distribution. These areas are called Petroleum Administration for Defense Districts (PADDs).[67] The Energy Information Administration (EIA) within the U.S. Department of Energy collects and disseminates information on petroleum use in the five districts.



Source: DOE 2009.

Figure C-1. Petroleum Administration for Defense Districts (PADD)

As illustrated in Figure C-1, the NESCAUM states are in PADD 1, along with all of the other east coast states. The EIA reports some state-specific data, but much of it is reported only as PADD totals. Where possible, data specific to the NESCAUM states are included in this section. However, in some circumstances only PADD 1 level information is readily available.

In collecting and presenting data, the EIA uses varying sources and terminology to report fuel consumption, sales and supply. For example, the term *product supplied* is not synonymous with *consumption*. Rather, it approximates consumption of petroleum products by tracking the disappearance of products from primary sources (i.e., refineries, blending plants, pipelines, and bulk terminals). EIA reports *prime supplier sales volumes* from data collected from companies that produce, import, or transport selected petroleum products across state boundaries and local marketing areas, and sell products to local distributors, retailers, or end users. *Sales by end use* data for distillate fuels are compiled from survey forms sent to a representative sample of companies doing business in four or

[67] In 1950, the Petroleum Administration for Defense (PAD) was established and five petroleum districts that had been established under the defunct Petroleum Administration for War (PAW) became the Petroleum Administration Districts for Defense or "PADDs." The PAD was abolished in 1954 and EIA now collects information on petroleum production and use.

more states and/or companies accounting for at least 5 percent of the distillate/residual fuel sales volume within any one state. Consequently, a table reporting prime supplier sales volumes (from the EIA or in this report) is not necessarily comparable to tables that report sales by end use or product supplied.

The table below compares the percentage of prime supplier sales volumes of principal fuel types in the NESCAUM region to sales in two other regions of PADD 1. It shows there are significant variations in fuel sales by type within PADD 1. For example, about two-thirds of the reformulated gasoline (RFG) supplied in PADD 1 goes to the NESCAUM region. In contrast, only about one-fourth of the low sulfur diesel fuel supplied to PADD 1 ends up in the NESCAUM region and more than half goes to the southern region. Therefore, in circumstances where the EIA reports fuels statistics at the PADD level only, caution must be exercised in drawing conclusions regarding fuel consumption, sales, and distribution within sub-regions.

Table C-1. Prime Supplier Sales Volumes of Petroleum Products (2005)

Percent Allocation within PADD 1

Product	NESCAUM	Mid-Atlantic[68]	Southern[69]
Conventional Gasoline	12.7	13.7	73.6
Reformulated Gasoline	67.6	20.9	11.5
No. 2 Distillate	38.1	19.1	42.8
- No. 2 Fuel Oil	60.2	20.5	19.3
- No. 2 Diesel Fuel	26.1	18.2	55.7
• Low Sulfur Diesel Fuel	24.8	18.3	56.9
• High Sulfur Diesel Fuel	35.7	17.3	47.0
Residual Fuel Oil	57.1	10.8	32.1
- Low Sulfur Residual Oil	75.6	12.4	12.0
- High Sulfur Residual Oil	38.5	9.2	52.3
Jet Fuel	43.3	13.9	42.7

C.1. Fuel Types and End Use

Table C-1 also shows that there is a variety of fuels in use within PADD 1, but not every fuel tracked by the EIA is listed here. For example, kerosene was omitted because its consumption is low, relative to the fuels listed. This analysis will emphasize gasoline and distillate fuel oil because of their higher consumption rates compared to the other fuels; the assumption being that these hold greater potential for partial replacement with alternatives that may achieve significant reductions in GHG emissions. The fuels in the table above are listed again in Table C-2 and Table C-3 immediately below, along with

[68] For purposes of this section, "Mid-Atlantic" refers to Delaware, the District of Columbia, Maryland, and Pennsylvania.
[69] For purposes of this section, "Southern" refers to Florida, Georgia, North Carolina, South Carolina, Virginia, and West Virginia.

their respective PADD 1 and NESCAUM sales volumes for the years 2003 through 2006, to provide a relative sense of their consumption volumes.

Table C-2. PADD 1 Prime Supplier Sales Volumes of Petroleum Products

(Millions of Gallons)

Product	**2003**	**2004**	**2005**	**2006**
Conventional Gasoline	30,097.2	30,229.8	30,216.6	30,638.8
Reformulated Gasoline	19,045.6	18,963.2	19,147.3	18,497.0
No. 2 Distillate	20,915.8	20,467.1	20,426.1	19,889.6
- No. 2 Fuel Oil	8103.3	7588.0	7215.3	5956.1
- No. 2 Diesel Fuel	12,812.5	12,879.1	13,210.8	13,933.5
• Low Sulfur Diesel Fuel	10,948.1	11,254.1	11,583.7	12,085.9
• High Sulfur Diesel Fuel	1864.4	1625.0	1627.1	1847.6
Residual Fuel Oil	6190.2	5556.2	5155.4	3664.5
- Low Sulfur Residual Oil	3138.0	2662.6	2592.9	1500.0
- High Sulfur Residual Oil	3052.2	2893.6	2569.1	2164.5
Jet Fuel	4442.4	4923.2	5610.7	5268.2

Source: DOE 2008.

Table C-3. NESCAUM Region Prime Supplier Sales Volumes of Petroleum Products

(Millions of Gallons)

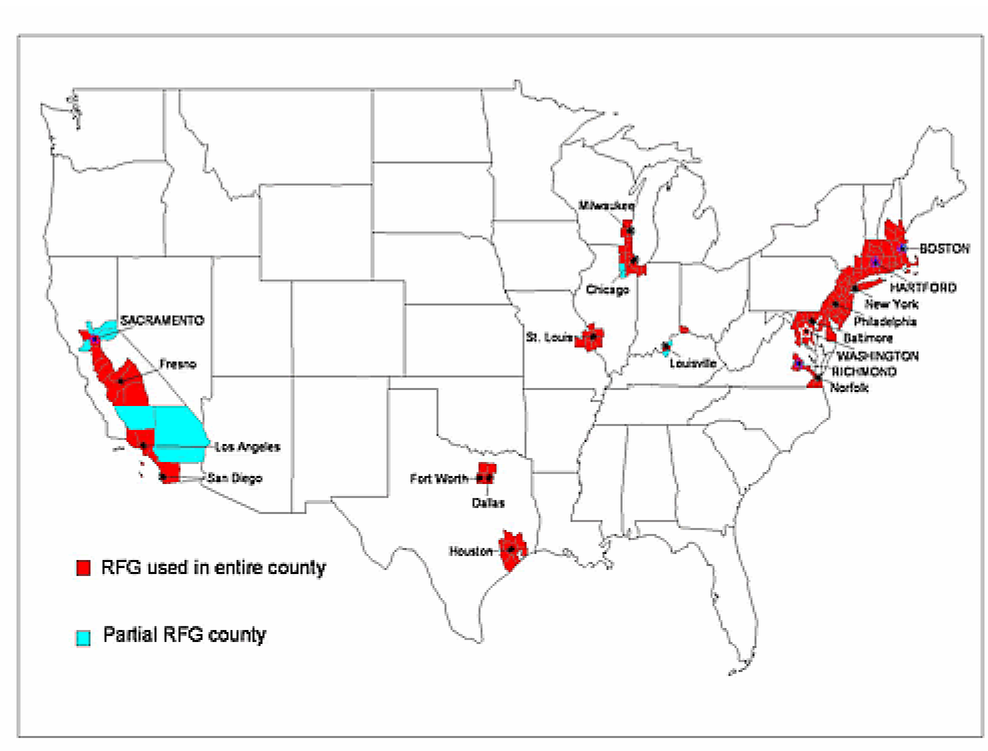
Product	**2003**	**2004**	**2005**	**2006**
Conventional Gasoline	3949.0	3895.1	3839.7	3960.4
Reformulated Gasoline	12876.0	12713.5	12950.5	12825.9
No. 2 Distillate	8648.8	8050.5	7792.4	7272.1
- No. 2 Fuel Oil	5029.8	4566.8	4340.4	3688.3
- No. 2 Diesel Fuel	3618.9	3483.7	3452.0	3583.7
• Low Sulfur Diesel Fuel	2884.7	2813.9	2871.4	3076.0
• High Sulfur Diesel Fuel	734.2	669.8	580.6	507.7
Residual Fuel Oil	2696.4	2803.7	2948.5	2229.2
- Low Sulfur Residual Oil	1740.2	1783.3	1959.6	1076.3
- High Sulfur Residual Oil	956.2	1020.4	989.0	1152.9
Jet Fuel	1904.6	2043.1	2431.8	2395.3

Source: DOE 2008.

Gasoline is the primary transportation fuel for light to medium duty passenger cars and trucks. Also, by virtue of numbers of vehicles and vehicle miles traveled, it represents the single largest fuel type supplied in PADD 1. Five general gasoline types are tracked by the EIA. They are reformulated gasoline (RFG), conventional gasoline (CG), their two respective blendstocks for oxygenate blending (RBOB and CBOB), and imported gasoline treated as blendstock (GTAB). The blendstocks are not listed separately in Prime Supplier Sales Volume statistics because they are not finished products, and therefore not sold to an end user.

The division of gasoline into the RFG and CG categories is rooted in historic strategies to assist ozone non-attainment areas in their efforts to attain federal air quality standards. Under Section 211(k) of the 1990 Clean Air Act amendments, the EPA Administrator promulgated regulations establishing requirements for RFG in specified areas. The regulations required "the greatest reduction in emissions of ozone forming volatile organic compounds (during the high ozone season) and emissions of toxic air pollutants (during the entire year) achievable through the reformulation of conventional gasoline."

Figure C-2, below, shows those areas in the U.S. presently required to use RFG. As indicated, much of the northeast region is included, but a significant amount of CG also is used in the region and other areas within PADD 1.



Source: EPA 2007.

Figure C-2. Areas in the U.S. Subject to RFG Requirements

Originally, there was a requirement for RFG to be blended with an oxygenate. This requirement typically was met by blending with methyl tertiary butyl ether (M*t*BE). Subsequently, several states banned the use of M*t*BE because of associated environmental problems, and ethanol became the substitute oxygenating compound. The figure below illustrates which states have either banned or are in the process of phasing out the use of M*t*BE. Most of the NESCAUM states have taken this step.

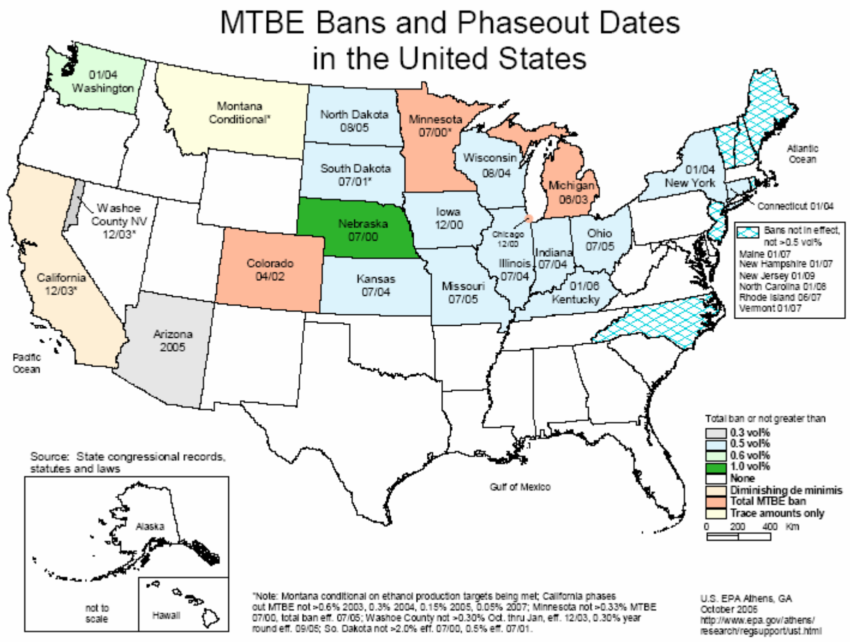


Figure C-3. U.S. M*t*BE Bans and Phase-out Dates

The RFG oxygenate requirement was removed under provisions in the Energy Policy Act (EPAct) of 2005. However, ethanol is still widely used in RFG, in part to make up the volume loss due to state-imposed M*t*BE bans. Table C-4 illustrates the increased trend of ethanol usage in the NESCAUM states as an RFG blending agent, coinciding with the phase out of M*t*BE. Ethanol supply and distribution infrastructure will be addressed in more detail later in this chapter.

Table C-4. Volumes of Oxygenates Added to Reformulated Gasoline in the NESCAUM Region

(Millions of Gallons)

	2003		2004		2005		2006	
State	M*t*BE	Et-OH	M*t*BE	Et-OH	M*t*BE	Et-OH	M*t*BE	Et-OH
CT	146.0	21	0.9	155	0.6	162	0.3	157
ME	0	0	0	0	0	0	0	0
MA	293.4	1	324.5	8	254.1	10	1.1	20
NH	57.5	0	57.2	0	53.0	0	0.1	0
NJ	483.8	1	501.5	6	481.7	7	0.9	15
NY	325.5	23	0.6	295	1.6	328	0.6	714
RI	47.9	1	56.5	8	49.7	10	0.2	20
VT	0	0	0	0	0	0	0	0
Total	**1354.1**	**47**	**941.2**	**472**	**840.7**	**517**	**3.2**	**926**

Sources: DOE 2008, EPA 2008.

Distillate is the general classification given to one of the petroleum fractions produced in petroleum refinery distillation operations and includes diesel fuels and fuel oils. No. 2 distillate comprises fuel oil and diesel. Residual fuel oil is also categorized as No. 6 distillate. Distillates have a much greater variety of applications compared to gasoline. Diesel fuel typically is used in on-highway diesel engines (e.g., trucks and buses), as well as nonroad engines (e.g., locomotives, agricultural machinery, construction equipment). Fuel oils are used primarily for space heating, steam production, and electric power generation. The NESCAUM states rely on liquid fuels to a much greater extent for power generation and heating compared to other regions of the country. Significant amounts of heavier residual fuels are used for electricity generation compared to other areas that rely more on natural gas or coal. The table below illustrates the array of principal sector end uses for four types of distillate fuel. Kerosene and No. 4 distillate are not included because their usage volumes are comparatively small.

Table C-5. NESCAUM Region Consumption of Distillate Fuels by End Use (2005)

(Millions of Gallons)

Sector End Use	No. 2 Fuel Oil	Low Sulfur Diesel Fuel	High Sulfur Diesel Fuel	Residual Fuel Oil
Highway	0	3166.0	-	0
Nonroad	0	-	172.7	0
Locomotive	0	0	150.9	0
Marine	0	0	133.0	1015.0
Home Heating	3515.7	0	0	0
Farm	13.5	-	52.6	0
Electric Power	77.2	0	0	2452.9
Industrial	100.0	16.8	12.8	338.1
Commercial	960.1	105.9	36.7	653.4
Total Usage	**4666.5**	**3288.7**	**558.7**	**4459.4**

Source: DOE 2008.

No. 2 distillate is the most highly used of all the distillate types in the NESCAUM region. Its single largest usage is as home heating oil, followed closely by highway (low sulfur[70]) diesel fuel. The major difference between these two distillates is in the sulfur content. Highway diesel fuel is subject to a federally mandated sulfur limit of 15 ppm, which will be fully phased in by 2010. There are no federal requirements limiting the sulfur content of home heating oil, and sulfur levels in the NESCAUM region average around 3000 ppm.

In 2004, EPA finalized a rule to control emissions from nonroad engines and fuels. Among its provisions, the rule required reductions in the sulfur content of nonroad diesel fuels. As a first step, sulfur levels were reduced from uncontrolled levels (typically around 3000 ppm) down to 500 ppm, effective in 2007. The second step will cap sulfur

[70] The term "low sulfur" is applied to any No. 2 distillate with a sulfur content of 500 ppm or less. Distillates with a sulfur content of 15 ppm or less are referred to as "*ultra-low* sulfur." The table above includes both low sulfur and ultra-low sulfur diesel fuel in the low sulfur column.

levels at 15 ppm in 2010, with the exception that the locomotive and marine sectors have until 2012 to achieve the 15 ppm sulfur standard. The 2005 consumption data presented in the table above for nonroad, locomotive and marine[71] sectors show exclusive use of high sulfur diesel fuel, but beginning in 2007, consumption will reflect the use of low sulfur diesel fuel for these sectors.

The farm sector includes establishments where the primary activity is growing crops or raising animals. Distillate use by all farm-related facilities and equipment is reflected in Table C-5, whether or not it is directly associated with growing crops or raising animals. Common types of fuel-consuming equipment include tractors, irrigation pumps, and crop dryers. Facility energy use encompasses all structures, including the farm house.

The electric power sector, also referenced in Table C-5, includes electricity-only plants, as well as combined heat and power plants whose primary business is to sell electricity or electricity and heat to the public. Distillate volumes directly imported and used by the electric power companies are included in the totals. Many power generation units utilize distillate and residual fuel either as primary or secondary fuel.

Almost all low sulfur diesel fuel, referenced as commercial sector, is highway fuel which is not subject to highway excise taxes and is used in school buses and government fleets. High sulfur diesel fuel in the commercial sector is used in engines that power nonroad vehicles and in stationary engines, such as emergency generators. No. 2 fuel oil is used in the commercial sector primarily to fire boilers, space heating equipment, and combined heat and power units.

Virtually all industrial sector diesel fuel (both high and low sulfur) is used in engines that power nonroad vehicles or power generating equipment. As is the case with the commercial sector, industrial sector No. 2 fuel oil is used in boilers and combined heat and power equipment.

Nonroad diesel internal combustion engines are also commonly used as the power source for on-site generation of electricity in the commercial and industrial sectors. These units typically are not directly connected to the transmission grid. However, they may be indirectly connected to the grid through their consumer's facilities, which are connected for backup purposes or to sell excess power.

In a 2003 report, NESCAUM estimated a total of 33,678 diesel engines were in the NESCAUM region for commercial and industrial electric generation purposes with the capability to generate 11.8 GW. Of the total, the vast majority (80 percent of the units providing 74 percent of the capacity) are used primarily or exclusively to provide back-up power in emergency situations (i.e., outage), and in some cases to reduce reliance on grid-supplied electricity during periods of peak demand. Consequently, most of these diesel generators are operated infrequently and it is difficult to estimate their

[71] Technically, marine fuels are classified differently from land-based distillate fuels. However, one of the most commonly used marine fuels, marine distillate fuel A (DMA), has properties very similar to No. 2 distillate fuel. DMA is the common fuel for tugboats, fishing boats, crew boats, drilling rigs, and ferry boats.

actual fuel consumption. The table below provides more detailed information on the population and size of these units in the region.

Table C-6. Estimated Diesel Generator Numbers & Capacity in NESCAUM Region

	Numbers of Units				Generating Capacity			
Rating (kW)	**Emergency**	**Peak**	**Baseload**	**Total**	**Emergency**	**Peak**	**Baseload**	**Total**
25-50	1768	0	0	1768	59	0	0	59
50-100	5798	1375	107	7280	462	114	9	584
100-250	9226	2236	95	11,577	1564	371	14	1949
250-500	5918	1231	7	7156	2126	443	3	2572
500-750	1296	316	47	1659	801	196	29	1026
750-1000	1164	292	51	1507	921	230	40	1191
1000-1500	641	677	39	1357	769	837	48	1654
1500+	1073	284	37	1394	2053	615	68	2736
Total	**26,884**	**6411**	**383**	**33,678**	**8756**	**2805**	**211**	**11,772**

According to the EIA in 2004, more than 1.5 billion gallons of high sulfur diesel fuel was consumed nationally in the commercial and industrial sectors. This total does not include distillate usage in the transportation, construction, or utility sectors. Of this total, approximately 4.7 percent was consumed for stationary energy production purposes by the two sectors. The NESCAUM region alone accounted for approximately 5.5 percent of the national total high sulfur diesel fuel usage in these two sectors but the actual consumption of fuel in diesel generators in the NESCAUM region is unknown, primarily because there is no centralized tracking system for fuel usage.

Combined heat and power (CHP) units are placed at or near commercial and industrial facilities to supply on-site energy needs, simultaneously producing useful thermal and electric power output, and thereby increasing overall efficiency. Onsite generation avoids the transmission and distribution losses associated with electricity purchased via a central grid, and units can be coupled with existing and planned technologies for many different applications. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling. Table C-7 summarizes the typical capacities, fuels, and uses of various types of CHP equipment.

Table C-7. Characteristics of Combined Heat and Power Technologies

Technology	Steam Turbine	Diesel Engine	Natural Gas Engine	Gas Turbine	Microturbine
Typical Capacity (MW)	0.2 – 800	0.03 – 5	0.05 – 5	1 – 500	0.03 – 0.35
Fuels	All	Diesel, Residual Oil	Natural Gas, Propane	Natural Gas, Propane, Oil	Natural Gas, Propane, Oil
Uses for Thermal Output	Steam	Hot Water, Steam	Hot Water, Steam	Hot Water, Heat, Steam	Hot Water, Heat, Steam

Source: EPA 2008.

Table C-8 summarizes distillate fuel consumption by CHP units in the NESCAUM states for commercial, industrial, and electric power sectors.

Table C-8. Annual Distillate Fuel Consumption (10^3 Gallons) – CHP Units (2005)

State	Commercial	Industrial	Electric Power	Total
Connecticut	69	4427	327	4823
Maine	261	38,830	43	39,134
Massachusetts	12,824	14,145	7110	34,079
New Hampshire	1733	13,159	--	14,892
New Jersey	386	7569	13,944	21,899
New York	16,802	18,772	7683	43,257
Rhode Island	3095	206	171	3472
Vermont	--	--	--	--
Total	**35,170**	**97,108**	**29,278**	**161,556**

Source: DOE 2008.

Industrial, commercial, and institutional boilers are primarily used for process heating, electrical or mechanical power generation, or space heating. Industrial boilers are used in all major industrial sectors but primarily by the paper products, chemical, food, and petroleum industries. Heat input capacity of industrial boilers is typically between 10 and 250 MMBtu/hr, however, there are even larger industrial boilers, similar to utility boilers. Commercial and institutional boilers generally are smaller than the industrial units, with heat input capacities generally below 10 MMBtu/hr. These units normally supply the steam and hot water for space heating in a wide range of locations, including wholesale and retail trade, office buildings, hotels, restaurants, hospitals, schools, museums, government buildings, and airports.

Process heaters are primarily used as heat transfer units in which heat from fuel combustion is transferred to process fluids in applications where boilers are inadequate. Process heaters are used in the petroleum refining and petrochemical industries, with minor applications in the asphalt concrete, gypsum, iron and steel, and wood and forest products industries.

C.2. Movement and Storage of Petroleum and Petroleum Products

PADD 1 states depend on a complex system of petroleum products transfer and imports to meet their fuel needs. Most of the crude oil that ultimately becomes finished product, destined for PADD 1, is refined in foreign countries or in other parts of the U.S., particularly the Gulf Coast States (PADD 3). Products are primarily moved via ocean going tanker, barge, and pipeline. Table C-9 summarizes the volumes of various petroleum products moving into and out of PADD 1.

Table C-9. Sources of Finished Petroleum Products in PADD 1

2005/2006 Annual Average (Millions of Gallons)

Source	Finished Gasoline	Light Distillates	Residual Fuel Oil	Jet Fuel
Produced in PADD 1	21,349 (43%)	7499 (34%)	1503 (21%)	1396 (14%)
Transported from PADD 2	239 (<1%)	138 (<1%)	8 (<1%)	26 (<1%)
Transported from PADD 3	23,863 (48%)	11,612 (52%)	690 (10%)	7514 (74%)
Transported from Canada	1426 (3%)	1409 (6%)	618 (9%)	131 (1%)
Other Import	5897 (12%)	3114 (14%)	4322 (61%)	1337 (13%)
Transported out of PADD 1	(3256) (-7%)	(1626) (-7%)	(8) (<-1%)	(283) (-3%)
Total	**49,518 (100%)**	**22,146 (100%)**	**7133 (100%)**	**10,121 (100%)**

One of the principal reasons that PADD 1 is so dependent on fuel imports and transfers is that petroleum refining capacity is limited relative to consumer need. Table C-10 shows the refinery capacity in PADD 1 for the streams that become distillates and gasoline. Most important is the comparison (bottom rows of the table) between capacities in PADD 1 and PADD 3. PADD 3 refineries have the capability of producing more than six times the gasoline components and almost five times the distillate volumes of PADD 1 refineries. Thus, PADD 3 produces an excess of products beyond its regional needs and transfers the excess to other markets, such as those in PADD 1.

Table C-10. Capacities of Operable Petroleum Refineries – PADD 1 (2006) and Comparison to PADD 3 Totals

Refinery	State	Production Capacity Gasoline Constituents (BBL/Stream Day)			Distillation Capacity (BBL/Calendar Day)
		Alkylates	**Aromatics**	**Isomers**	**Distillates**
Premcor (Valero) – Delaware City	DE	11,729	1700	6000	182,200
Chevron – Perth Amboy	NJ				80,000
Conoco Phillips – Linden	NJ	18,000		4000	238,000
Hess – Port Reading	NJ	7000			
Sunoco – Westville	NJ	4000	7500	10,000	145,000
Valero – Paulsboro	NJ	11,200			160,000
American – Bradford	PA				10,000
Conoco Phillips – Trainer	PA	12,000			185,000
Sunoco – Marcus Hook	PA	12,000	8000		178,000
Sunoco – Philadelphia	PA	26,000	4920	5000	335,000
United – Warren	PA	4100		6800	65,000
Giant – Yorktown	VA	4200			59,375
Ergon – Newell	West VA				20,000
Totals		**110,229**	**22,120**	**31,800**	**1,657,575**
Comparable PADD 3 Totals		**580,850**	**223,000**	**237,025**	**7,989,609**

Source: Petroleum Refiners Association 2007.

In addition, three Atlantic Province Canadian refineries supply petroleum products to the NESCAUM region. The refineries and their overall capacities are listed in Table C-11, immediately below.

Table C-11. Capacities of Atlantic Province Canadian Refineries Partially Supplying the NESCAUM Region (BBL/Day)

Company	Location	Capacity
Imperial Oil	Dartmouth, NS	88,017
Irving Oil	Saint-John, NB	280,034
North Atlantic Refining	Come-by-Chance, NFLD	105,051

Source: Natural Resources Canada 2008.

As previously indicated, products are moved into PADD 1 from PADD 3 via pipeline, tanker, and barge. To a lesser extent, products are also moved into PADD 1 from the Midwest states (PADD 2). Table C-12, below, displays the relevant petroleum product volumes.

Table C-12. Petroleum Products – Movement into PADD 1 from PADDs 2 & 3

Pipeline, Tanker, & Barge – 2005/2006 Annual Average
(Millions of Gallons)

	Pipeline		Tanker & Barge		
Product	**From PADD 2**	**From PADD 3**	**From PADD 2**	**From PADD 3**	**Total**
Crude Oil	98.1	120.3	132.3	0	350.7
RFG	0	2460.8	0	3.9	2464.7
CG	22.5	16,181.2	216.9	5216.8	21,637.4
RBOB	0	1659.8	1.1	25.5	1686.4
CBOB/GTAB	0	0	0	31.3	31.3
HS Diesel/Fuel Oil	0.9	3563.0	52.2	261.5	3877.6
LS Diesel	1.6	6424.7	83.0	1362.8	7872.1
LS Residual	0	0	0	220.0	220.0
HS Residual	0	0	8.2	470.4	478.6
Jet Fuel	13.9	6184.7	12.1	1329.0	7539.7

In addition, petroleum and petroleum products are imported via tanker directly into PADD 1 from foreign sources. Table C-13 lists, by world region, the principal sources of these imports.

Table C-13. Petroleum Products – Foreign Imports into PADD 1 By Continent of Origin – 2005/2006 Annual Average

(Millions of Gallons)

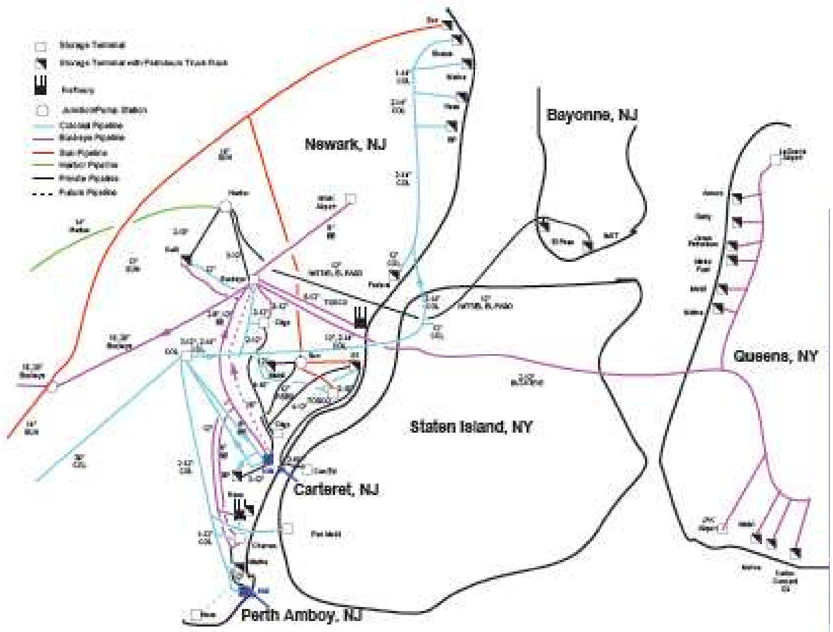
Product	North America	South America	Caribbean	Europe	Africa	Middle East	Other	Total
Crude Oil	3572 (15%)	2847 (12%)	0 (0%)	1624 (7%)	12,620 (53%)	2870 (12%)	250 (1%)	23,784 (100%)
RFG	1154 (53%)	147 (7%)	386 (18%)	499 (23%)	1 (<1%)	7 (<1%)	3 (<1%)	2192 (100%)
CG	274 (5%)	325 (6%)	975 (19%)	3357 (65%)	19 (<1%)	56 (1%)	126 (2%)	5131 (100%)
RBOB	724 (31%)	163 (7%)	450 (19%)	903 (39%)	13 (<1%)	11 (<1%)	57 (2%)	2319 (100%)
CBOB	66 (1%)	465 (9%)	88 (2%)	3851 (79%)	213 (4%)	39 (<1%)	179 (4%)	4900 (100%)
Ethanol	3 (1%)	191 (70%)	10 (4%)	1 (<!%)	0 (0%)	0 (0%)	69 (25%)	274 (100%)
Fuel Oil	152 (18%)	564 (67%)	23 (3%)	106 (13%)	0 (0%)	0 (0%)	1 (<1%)	845 (100%)
LS Diesel	835 (41%)	73 (4%)	821 (41%)	210 (10%)	7 (<1%)	0 (0%)	78 (4%)	2022 (100%)
HS Diesel	423 (26%)	117 (7%)	762 (46%)	274 (17%)	0 (0%)	0 (0%)	81 (5%)	1656 (100%)
LS Residual	164 (7%)	762 (35%)	323 (15%)	261 (12%)	486 (22%)	9 (<1%)	201 (9%)	2203 (100%)
HS Residual	602 (22%)	637 (23%)	971 (35%)	359 (13%)	52 (2%)	0 (0%)	118 (4%)	2737 (100%)
Jet Fuel	151 (10%)	500 (34%)	663 (45%)	24 (2%)	15 (1%)	91 (6%)	25 (2%)	1468 (100%)

C.3. Major Supply Points for Petroleum & Petroleum Products

There are numerous individual supply points, providing petroleum products to the northeast region. Principal ones are in New York Harbor, Albany/Hudson River, and Delaware River/Bay. Secondary supply points include port terminals located in Boston, MA; Portland, ME; Portsmouth NH; New Haven, CT, and Providence, RI. As fuels reach these ports, barges, tank trucks, pipelines, and to a lesser extent, rail are used to distribute fuels throughout the region. The region is also supplied by a major interstate pipeline (Colonial Pipeline) and three others, operated by Buckeye Partners, Sunoco, and ExxonMobil.

C.4. Port Facilities

New York Harbor could be considered the central supply point in the region for receipt and distribution of petroleum products. It is also the center for the water movement of heating oil and residual fuel for electricity generation facilities. Distribution of heating oil involves terminals of different sizes, distributors, and companies that have terminals to store heating oil and the means to distribute it. Figure C-4, immediately below, illustrates the complex nature of the petroleum distribution infrastructure in New York Harbor.



Source: Kinder Morgan 2007.

Figure C-4. Petroleum Infrastructure Distribution in New York Harbor

The Port of New York and New Jersey encompasses the ports of both states, with a total of 1,500 square miles, including 17 counties and 234 municipalities. Eight separate bays and associated waterways provide 755 miles of frontage of which 460 miles are in New York and 295 miles are in New Jersey, including navigable portions of the Hackensack, Passaic, and Raritan Rivers on the west; and Raritan and Sandy Hook on the south. The Port Authority administers piers in Manhattan, Brooklyn, Hoboken, Port Newark, and Port Elizabeth.

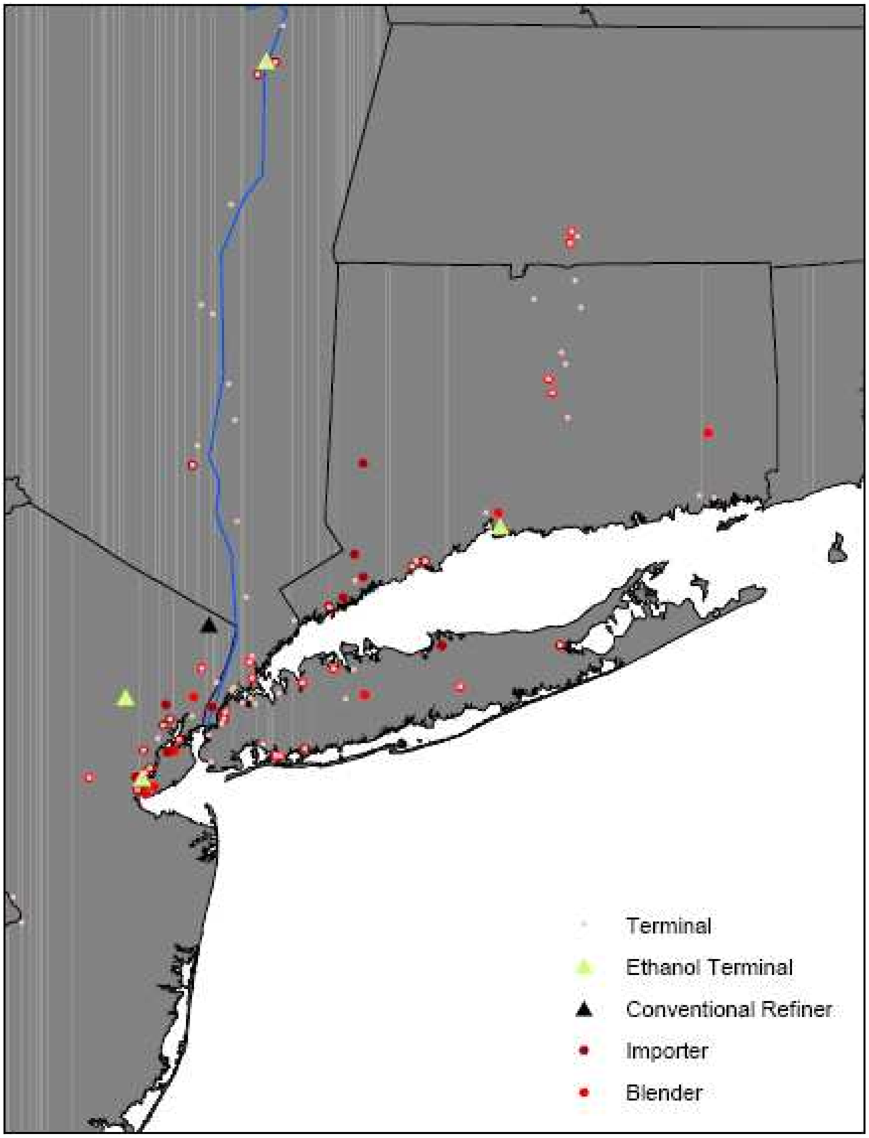


Figure C-5. Petroleum Facilities - New York/New Jersey & Albany/Hudson River Area Ports

The Hudson River rises in the Adirondack Mountains of New York and flows 315 miles in a southerly direction into New York Harbor. At Waterford, the river connects with the New York State Barge Canal system, which provides channels to the Great Lakes port of Oswego, New York, and to improved waters in Canada leading to the St. Lawrence River. The Port of Albany, New York, is on the bank of the Hudson River about 143 statute miles north of New York Harbor. The port is the terminus of the deep-draft Hudson River and is the principal port above New York City. There are 98 waterfront piers, wharves, and docks on the Hudson River. Eight of these facilities are within the Port of Albany. A total of 80 port facilities are located on the Hudson River above and below the Port of Albany.

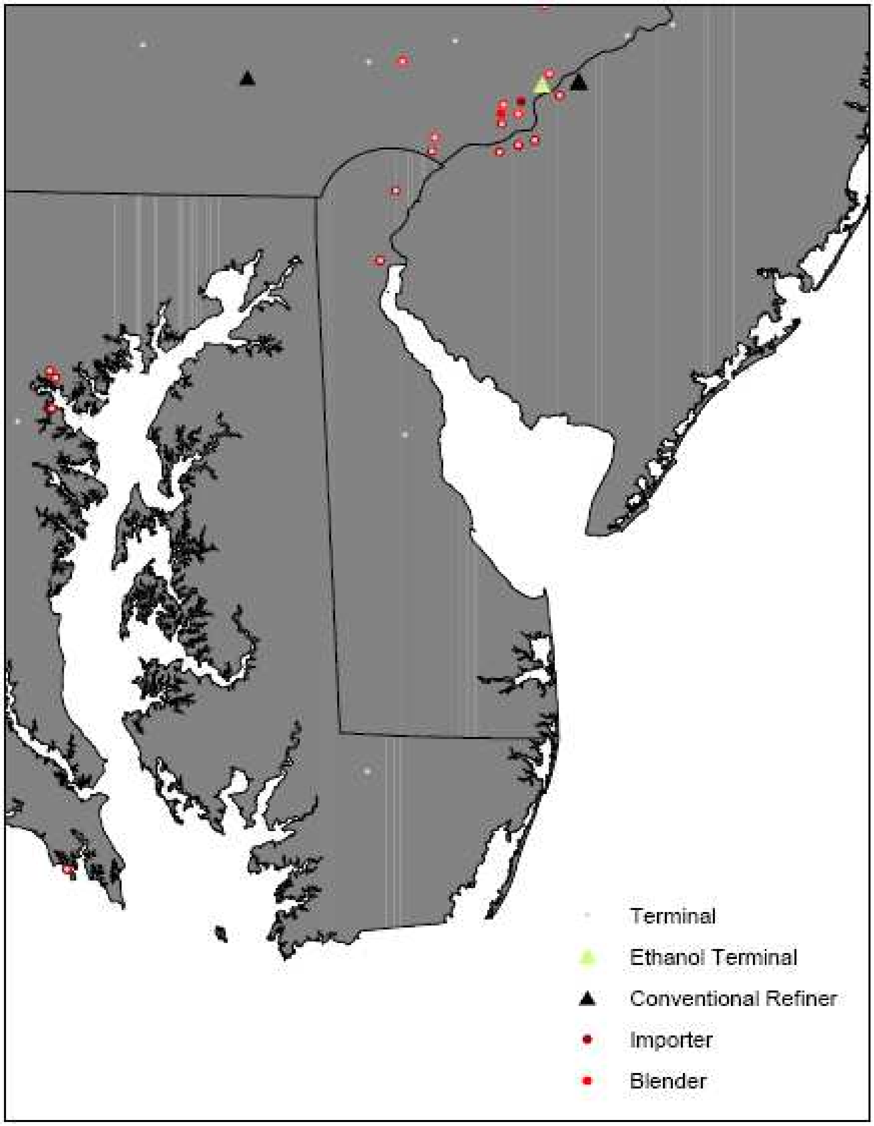


Figure C-6. Petroleum Facilities - Delaware Bay/River Ports

The Delaware Bay and the Delaware River form the boundary between the State of New Jersey on the east and the States of Delaware and Pennsylvania on the west. The Delaware Bay is an expansion of the lower part of the Delaware River, and the entrance is about 10 nautical miles wide between Cape May and Cape Henlopen. Deep draft vessels use the Atlantic Ocean entrance while vessels with drafts of less than 33 feet can enter the Delaware River from the Chesapeake Bay through the Chesapeake and Delaware Canal. This canal provides an alternate protected waterway connecting the Delaware River and Chesapeake Bay ports.

The Delaware Bay and the Delaware River represent the principal artery for waterborne commerce for Philadelphia, PA, Wilmington, DE, Chester, PA, and Marcus Hook, PA. It also is the major artery for Camden, Trenton, and Salem, NJ. More than 190 piers, wharves, and docks are available along the waterfront areas to handle petroleum products, miscellaneous bulk commodities, and a variety of dry bulk materials and liquid commodities. The entire Delaware River system ranks as the fifth largest U.S. seaport, due to the River's concentration of oil refineries and oil import terminals. The City of Philadelphia's portion of the Delaware River system includes navigable sections of the Schuylkill River.

Located adjacent to Philadelphia International Airport, the Hog Island Shipping Terminal is predominantly used for oil and gas products. In addition, Marcus Hook is an important petroleum center where large quantities of crude oil are received, and refined petroleum products are shipped. The Camden city waterfront includes the petroleum terminals at Petty's Island and Fisher Point Dike.

C.4.1 Pipelines

Colonial Pipeline moves petroleum products from the Gulf Coast in PADD 3 to New Jersey and New York (see Figure C-5 above), along more than 5000 miles of pipeline. A network of smaller pipelines branches out from the end of the main line in Linden, NJ, to a number of locations throughout New York Harbor. Linden is a large junction where the Colonial Pipeline connects with other intraregional pipelines, which connect, in turn, to several terminals and refineries. This Intra Harbor Transport Service connects to petroleum products terminals on the Hudson River owned by companies such as Motiva, Hess, and BP. The pipeline also connects to the Buckeye and the Sunoco pipelines.

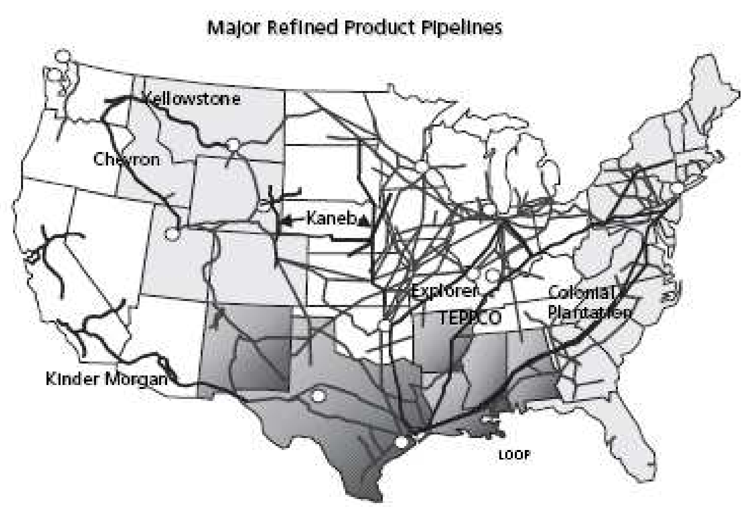


Figure C-7. Colonial & Other Major Interstate Petroleum Product Pipelines

Colonial Pipeline system annually moves approximately 900 million barrels of petroleum products from PADD 3. At Greensboro, NC, the volume on the line is reduced to around 365 million barrels annually, continuing to the New York Harbor terminus. It is estimated that 30 to 40 percent of this capacity is distillate fuels and the remainder (60-70 percent) is gasoline, jet fuel and other light products.

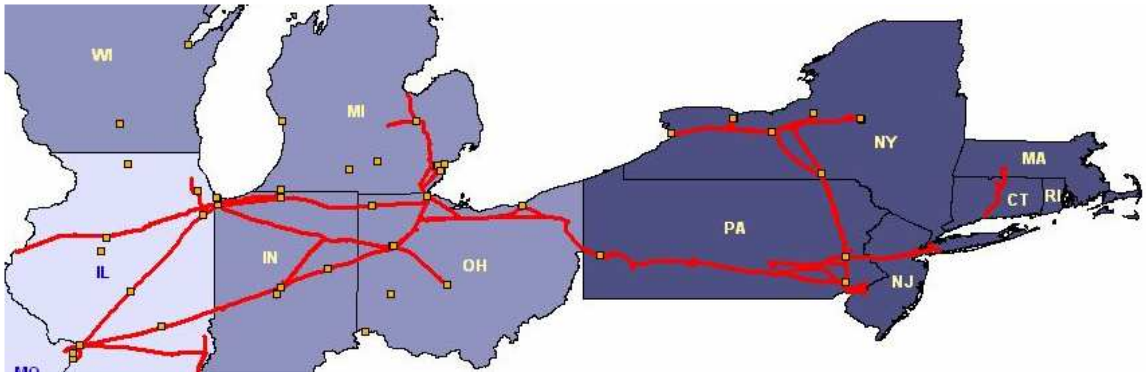


Figure C-8. Buckeye Pipeline

The Buckeye Pipeline serves Pennsylvania, New York, and New Jersey. Petroleum products are received at Linden, NJ, from approximately 17 major source points, including two refineries, six connecting pipelines, and nine storage and terminalling facilities. The products are then transported through one line to Newark and through two additional lines to JFK and La Guardia airports, and further onto terminals at Long Island City and Inwood, NY. JFK Airport is connected to the Inwood Terminal from which the airport gets all its aviation fuel and La Guardia to the Long Island City terminal.

Additionally, Buckeye operates a line that moves petroleum products from Pennsylvania into south central New York. In New York, the line splits, traveling east through Syracuse and terminating in Utica, and west (with a spur to Rochester) terminating in Buffalo. Buckeye also operates a line, transporting product from the port of New Haven, CT, through Hartford, and terminating in Springfield, MA.

Figure C-9. Sunoco Pipeline

Sunoco has three lines (Western, Terminal Facilities, and Eastern) totaling 1,740 miles and transporting product from Sunoco refineries and terminals in Philadelphia, PA; Marcus Hook, PA; Eagle Point, NJ, and Toledo, OH. These lines also transport product from third parties to markets in New York, New Jersey, Pennsylvania, Ohio, and Michigan. Two additional lines transport product north from Pennsylvania to Rochester, Buffalo, and Syracuse, NY.

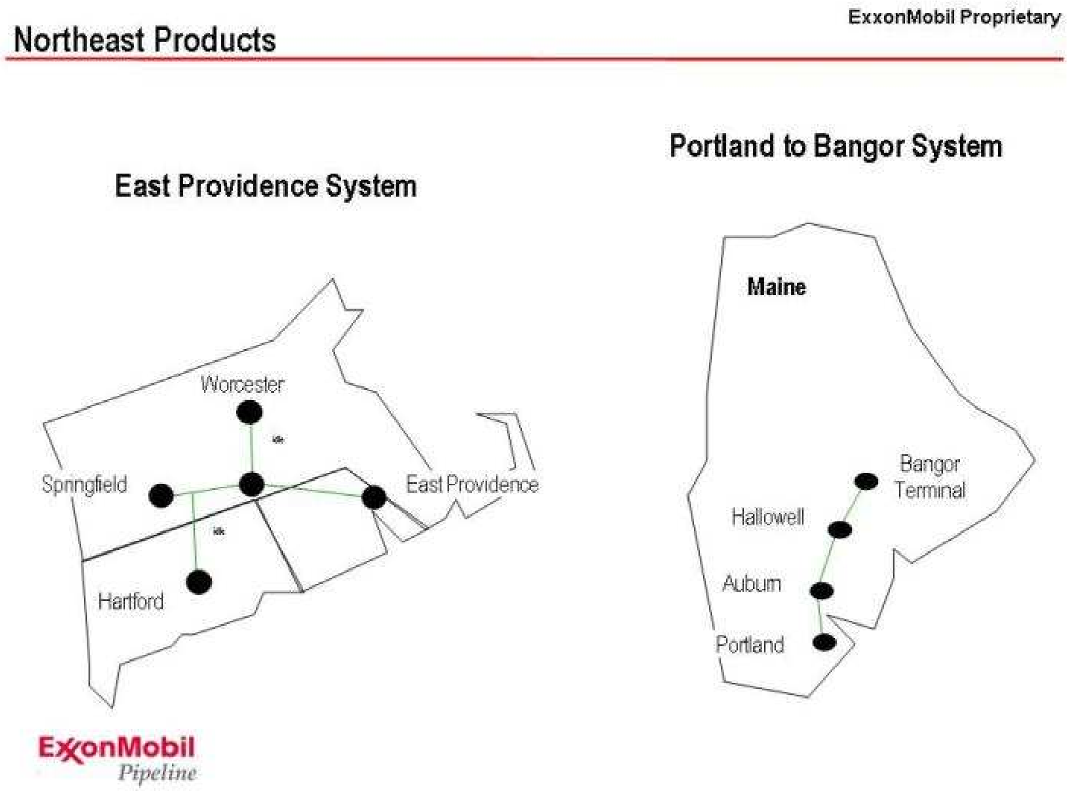


Figure C-10. ExxonMobil Pipelines

ExxonMobil has three pipeline systems in the region. The 124-mile Portland to Bangor system originates in Portland, ME, and terminates in Bangor, delivering product to ExxonMobil, Coldbrook Energies, and Weber Energy terminals. The 84-mile East Providence to Springfield system originates in East Providence, RI and terminates in Springfield, MA. The 472-mile Paulsboro NJ/PA/NY system serves ExxonMobil's Paulsboro, NJ, Pennsylvania, and New York terminals.

C.4.2 Terminals

Terminals are the point in the distribution system where product typically is dispensed into transport trucks for delivery to wholesale and retail customers or to smaller bulk plants. Table C-14 lists the capacities of the principal terminal companies and includes a figure for the total terminal capacity within the NESCAUM region.

Table C-14. Petroleum Product Terminal Capacity in the NESCAUM Region

(Thousands of Barrels)

Company	Capacity	Company	Capacity
IMTT	15,300	Irving Oil	2,609
Sprague Energy	12,269	New Haven	2,500
Amerada Hess	9,990	Buckeye Terminals	2,329
Kinder Morgan	9,949	Global Companies	1,341
Motiva Enterprises	8,840	TEPPCO	1,216
ExxonMobil	8,419	Sunoco Logistics	1,190
CITGO Petroleum	6,173	Pacific Atlantic	1,156
Carbo Industries	5,900	NOCO Energy	1,113
Magellan	3,900	Center Terminal	975
ST Linden Terminal	3,884	Castle Oil	807
Gulf Oil	3,550	All Others	12,562
NRG	3,043	Total	122,797
Portland Pipeline	2,634		

Table C-15. Petroleum Product Terminals in Delaware River Region of Southeastern Pennsylvania[*] Potentially Supplying the NESCAUM Region

Company	Number of Terminals	Company	Number of Terminals
121 Point Breeze	1	Gulf Oil	1
Aircraft Service, Intl.	1	HOP Energy	1
Amerada Hess	1	Kinder Morgan	1
Buckeye	2	Meenan	1
ConocoPhillips	1	Pacific Atlantic	3
Farm and Home Oil	3	Petroleum Products	2
Global	1	Sunoco Partners	9

[*]Counties of Berks, Bucks, Chester, Delaware, Lancaster, Lehigh, Montgomery, & Philadelphia.

C.5. Ethanol Transport, Supply and Distribution

Ethanol is expected to be an ever increasing component of U.S. transportation fuels for many years to come, particularly due to recent federal mandates. The majority of the fuel ethanol presently supplied to the Northeast and other U.S. markets comes from Midwestern distillers who convert corn starch into ethanol. The Energy Policy Act of 2005 established minimum volumes of “renewable fuel” to be added to the fuel supply, beginning in 2006 with a 4 billion gallon requirement. This requirement was largely met by supplying ethanol. In fact, in the same year, the domestic ethanol industry produced 4.9 billion gallons of ethanol. An additional 0.7 billion gallons were imported into the U.S. in the same timeframe.

The Energy Independence & Security Act (EISA) of 2007 increases the renewable fuel mandate. In 2008, the minimum requirement for consumption of renewable fuel is 9 billion gallons, ramping up to 36 billion gallons by 2022. Beginning in 2009, a modest portion of this mandate must be met through the consumption of "advanced biofuel," which is the broad category of renewable fuels other than ethanol produced from corn starch. By 2022, the advanced biofuel requirement ramps up to 21 billion gallons, meaning among other things, that 15 billion of the overall 36 billion gallon requirement may still be satisfied through the use of ethanol produced from corn starch.

The demand for ethanol in the Northeast is largely driven by RFG requirements. As mentioned previously in this chapter, although the oxygenate mandate for RFG is no longer in effect, RFG states depend on ethanol to make up the volume losses that were the consequence of M*t*BE bans. Thus, ethanol is present in gasoline supplied to the entire states of Connecticut, Massachusetts, New Jersey, and Rhode Island. In 2006, approximately 1.2 billion gallons of ethanol were added to Northeast's RFG, of which 0.5 billion gallons were imported, reflecting a 10 fold increase in imports from the prior year.

There is no particular incentive for supplying ethanol to states where RFG is not required. If the cost of ethanol is less than gasoline, then ethanol is more likely to be present in non-RFG markets. However, if the opposite is true, there is a disincentive to supply ethanol. Consequently in the NESCAUM region, there is limited penetration of ethanol into markets in upstate New York, Vermont, Maine, or outside the southeastern counties of New Hampshire.

More than 75 percent of the domestically produced ethanol is transported by rail. A typical ethanol "unit train" consists of approximately 100 tank cars, each with a capacity of about 30,000 gallons. Nationally, there are approximately 15,000 such tank cars in ethanol service. Two major railroad companies, Norfolk Southern and CSX, are the primary transporters of fuel ethanol from the Midwest to the Northeast. In 2006, Norfolk Southern moved more than one billion gallons of ethanol nationally. A third major railroad company, Canadian National Railroad, may become a major ethanol transporter to developing markets in northern New England. Certain smaller railroad companies, such as Providence & Worcester and St. Lawrence & Atlantic, also play a role in moving ethanol from the terminus of the major rail lines to local storage terminals.

There are four major ethanol terminals, supplying the markets in the NESCAUM region located in Albany, NY. Providence, RI, Linden, NJ, and Sewaren, NJ. A fifth facility in Auburn, ME opened in late 2007, and has the potential to become a major supplier, depending on future demand for fuel ethanol in northern New England. Major Terminals in Philadelphia, PA and Baltimore, MD as well as a major production facility undergoing construction in Westmoreland County, PA (primarily serving the Mid-Atlantic) may play a role in supplying northeast customers. Below is a brief description of each facility and its supply structure.

LogiBio Albany (NY) Terminal

The LogiBio Terminal is the former Cibro Petroleum Products terminal. In 2006, the facility handled almost 336,000,000 gallons of ethanol. The terminal has over

21,000,000 gallons of ethanol storage capacity and receives product from the Midwest via CSX trains, with the ability to unload 80 railcars at a time. In addition, the facility has the ability to receive and load out product to barges traveling the Hudson River. It also has a truck loading facility for local deliveries. Via barge, ethanol is delivered to markets in New York City, Bridgeport, CT, New Haven, CT, Providence, RI, and Boston/Revere, MA.

U.S. Development Group New York Harbor (Linden, NJ) Terminal

This terminal was originally only served by barge and truck, receiving the bulk of its ethanol from foreign sources. Beginning in 2007, the terminal added rail capacity to receive 100-car unit trains of domestically produced ethanol from Norfolk Southern and CSX rails. The terminal is now capable of handling 250 ethanol rail cars at one time and is able to store 21 million gallons of ethanol.

U.S. Development Group Baltimore (MD) Harbor Terminal

This terminal is undergoing development from a small railcar facility in Curtis Bay, south of Baltimore, into a facility which can handle 120 railcar spots and ultimately the ability to handle 100-car unit trains. The Baltimore facility also has barge docks and truck racks. Storage capacity is 12.6 million gallons. It is unknown if this terminal serves locations in the NESCAUM region, but because of its proximity, it is possible.

Motiva Enterprises Providence (RI) Terminal

The Providence, RI Motiva terminal is one of two principal petroleum products terminals located in Providence and serving Rhode Island, parts of Connecticut, and southeastern Massachusetts. The terminal originally received ethanol shipments exclusively by barge. In 2007, Motiva completed a rail facility to accommodate unit trains of ethanol arriving on tracks owned by the Providence & Worcester Railroad. Ethanol is transported from the Midwest via trains operated by CSX and stored in a series of existing tanks at the facility with a capacity of 63 million gallons.

Motiva Enterprises Sewaren (NJ) Terminal

Motiva expanded its petroleum products handling operations at Sewaren in 2005 to become the largest ethanol storage terminal in the New York Harbor area, serving customers in New York and Connecticut. The facility is able to handle more than 2 million gallons of ethanol per day, brought in by unit trains of the Norfolk Southern Railway.

Aventine Renewable Energy Philadelphia (PA) Terminal

This Aventine terminal receives ethanol by rail service provided by CSX.

Safe Handling Auburn (ME) Terminal

The Auburn-based terminal opened a rail-to-truck ethanol transloading terminal in December 2007 to serve potential northern New England markets. The facility does not store ethanol in permanent onsite tanks. Rather, the facility can accommodate up to 210 rail cars at a time for a total capacity of 6.3 million gallons. Ethanol will come from the Midwest and Canada via the Canadian National Railroad on haulage agreement with the St. Lawrence & Atlantic Railroad.

Commonwealth Renewable Energy Production Facility (Westmoreland County, PA)

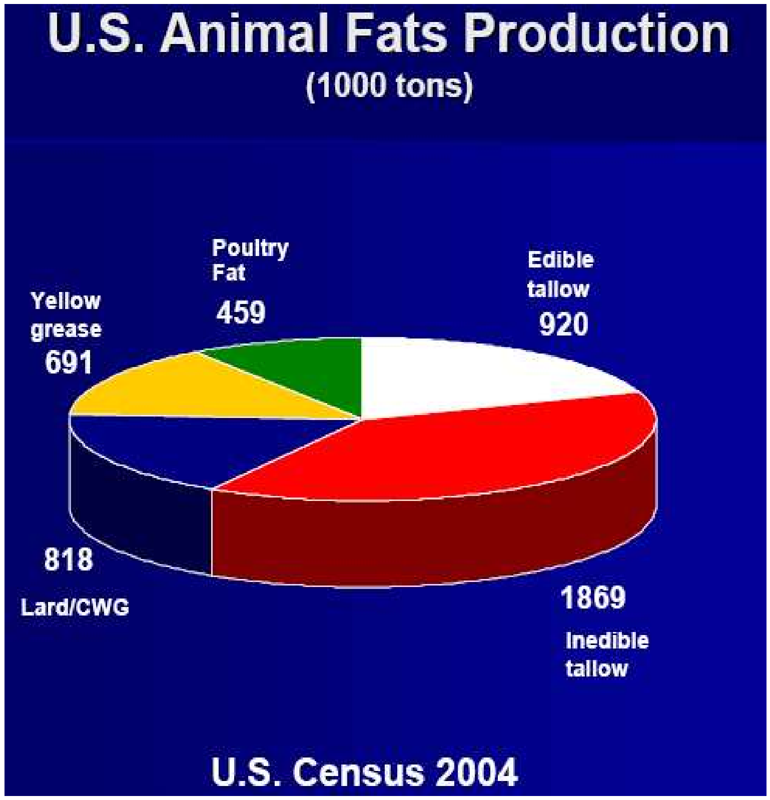
This giant is undergoing construction in southwestern Pennsylvania. Touted as "the country's largest ethanol plant," plans are to largely use locally grown corn as the raw material source to produce 200 million gallons of ethanol annually. A major line of the Norfolk Southern Railway passes near the facility.

Magellan Midstream Partners (New Haven, CT)

Magellan operates an ethanol supply network of vessels and trucks serving Connecticut and Massachusetts. The facility has an ethanol storage capacity of 142,000 barrels. In 2007, its throughput was 1,557,699 barrels.

C.6. Yellow Grease & Inedible Tallow as a Potential Biodiesel Resource

Animal fats are a potentially significant source of renewable energy, either as a raw material for the production of methyl esters (biodiesel) or for direct firing in their unaltered fatty acid form as boiler fuel. The principal animal fats produced in the United States are yellow grease, poultry fat, edible tallow, inedible tallow, and lard. Figure C-11 illustrates their relative proportions. It should be noted that animal fats are not considered a waste product. Virtually all are used in the manufacture of various products, including human food, animal feed, cosmetics and lubricants. Tallow is considered edible if it is fit for human consumption. So-called inedible tallow is most commonly used in animal feed. Yellow grease is derived primarily from used cooking oil and fryer grease from restaurants and is mostly used as a supplement in animal feed. Inedible tallow and yellow grease typically have lower economic value compared to the other animal fats and therefore are the better candidates for use as fuel.



Source: National Renders Association 2006.

Figure C-11. Breakdown of U.S. Animal Fats Production

As indicated above, yellow grease is a byproduct of the restaurant industry. There is a direct correlation between the amount of restaurant food produced in an area and that area's population. Therefore, one approach to estimating the amount of yellow grease produced in a state is to base the estimate on state population. According to the U.S. Census Bureau, 1335.6 million pounds of yellow grease were produced in the United States in 2005. The estimated U.S. population, also according to the U.S. Census Bureau, on July 1, 2005 was 295.9 million. Thus the U.S. per capita yellow grease production in 2005 was approximately 4.5 pounds. Using this number in conjunction with 2005 population estimates for each state, calculations in Table C-16 estimate the annual yellow grease production for the eight NESCAUM states plus Maryland and Pennsylvania. According to the DOE, 7.65 pounds of fat will yield a gallon of biodiesel. Thus, the equivalent biodiesel volume is included in the same chart below.

Table C-16. Estimated Yellow Grease Resource & Equivalent Biodiesel Production Potential

State	Yellow Grease (10^6 Pounds)	Biodiesel Equivalent (10^6 Gallons)
Connecticut	15.7	2.0
Maine	5.9	0.8
Massachusetts	28.9	3.8
New Hampshire	5.9	0.8
New Jersey	39.0	5.1
New York	86.7	11.3
Rhode Island	4.8	0.6
Vermont	2.8	0.4
Maryland	25.1	3.3
Pennsylvania	55.7	7.2
Total:	**270.5**	**35.3**

Population is not a good indicator for estimating the inedible tallow resource in a state. Independent of population, this resource in any given state is more directly related to the level of activity of the state's animal slaughtering and processing industry. The U.S. Census Bureau's 2002 Economic Census compiled data on the animal slaughtering and processing industry in each state, including each state's total value of products shipped. Thus, the approach used to estimate the available tallow resource for each state was to apportion the 2005 U.S. total of 3637.1 million pounds of inedible tallow produced, according to the 2002 Economic Census report of total value of products shipped for each state. Consistent with the methodology used to estimate potential biodiesel production from yellow grease, the Department of Energy's factor of 7.65 pounds of fat yielding a gallon of biodiesel was used to estimate the equivalent biodiesel volume from the inedible tallow resource. The results are given in the table below.

Table C-17. Estimated Inedible Tallow Resource & Equivalent Biodiesel Production Potential

State	Inedible Tallow (10^6 Pounds)	Biodiesel Equivalent (10^6 Gallons)
Connecticut	4.9	0.6
Maine	3.2	0.4
Massachusetts	15.2	2.0
New Hampshire	0	0
New Jersey	26.8	3.5
New York	30.2	3.9
Rhode Island	2.0	0.3
Vermont	1.2	0.2
Maryland	20.8	2.7
Pennsylvania	112.2	14.6
Total:	**216.5**	**28.2**

Possibly the most expedient means of utilizing yellow grease and inedible tallow for biodiesel production or for direct firing in a boiler is to produce and use it at existing rendering plants. This strategy utilizes existing processing, transport, and supply infrastructure and avoids the problems associated with attempting to site new rendering plants in communities where they may not be welcome. In the Northeast, existing rendering plants are not uniformly distributed. Out of a national population of approximately 229 plants, there are only 15 in the Northeast. Nine of those 15 are located in a single state (Pennsylvania). Table C-18 assumes that the entire yellow grease and inedible tallow resources in the eight NESCAUM states, plus the Maryland and Pennsylvania, are directed to these 15 facilities and all of the resource is converted to biodiesel at the facilities.

Table C-18. Biodiesel Production Potential (10^6 Gallons) for Northeast Rendering Plants Based on Numbers of Plants in Each State and 2005 Raw Material* Supply

State	Numbers of Plants	Raw Material	Biodiesel Volume
Massachusetts	2	64.9	8.5
New Jersey	1	32.5	4.2
Maryland	3	97.4	12.7
Pennsylvania	9	292.2	38.1
Total:	**15**	**487.0**	**63.5**

*Raw Material is the combined estimated 2005 total yellow grease & inedible tallow (10^6 pounds)

C.7. Liquefied Natural Gas in the Northeast

General Facts & Figures (2005)

Total natural gas consumed in the 8 NESCAUM states:	2,446,193 million cubic feet
Total natural gas consumed in the 6 New England states:	763,590 million cubic feet
Percentage of LNG in the total U.S. natural gas supply:	3 percent

Everett (MA) LNG Facility

This facility, operated by Distrigas of Massachusetts, is the exclusive supplier of LNG to the New England states. In 2005, Distrigas imported 168,542 million cubic feet of natural gas into the facility, all from Trinidad and Tobago, accounting for 22 percent of total natural gas consumption in New England.

This facility is the exclusive supplier of natural gas to Boston Generating LLC Mystic Generating Station (power plant). Of all the LNG imported into the Everett facility in 2005, 35 percent (59,559 million cubic feet) went to the Mystic Generating Station. The remainder was distributed by pipeline or truck to other customers.

If the LNG delivered to Mystic is subtracted from the total, then 15 percent of the natural gas demand in New England is supplied by LNG from the Everett Facility.

Cove Point (MD) LNG Facility

The Cove Point LNG facility, operated by Dominion Cove Point LNG, is the supplier of LNG for the Mid-Atlantic. There is no indication that any of the LNG is supplied to markets in the NESCAUM states. In 2005, Dominion imported 221,689 million cubic feet of natural gas into the facility, mostly from Trinidad and Tobago. Dominion supplies natural gas to power plants operated by Dominion Virginia Power and Fairless Energy (PA). In 2005, the seven natural gas fired power generating units consumed 35,588 million cubic feet of natural gas, of which an undetermined percentage was LNG, originating from the Dominion Cove Point facility.

Lake Charles (LA) LNG Facility

This facility, operated by Trunkline LNG Company, supplies LNG via the Trunkline natural gas pipeline, which follows the Mississippi River up to Illinois and then across Illinois and northwestern Indiana, terminating at the Indiana-Michigan border. A branch line (Panhandle Eastern) runs from Oklahoma and Texas in the west, terminating at Detroit in the east. There is one power generating facility in Oswego, NY (Independence Station – Sithe Energies, Inc) that receives an undetermined amount of natural gas, originating from the Lake Charles LNG Facility. In 2005, Trunkline imported 103,770 million cubic feet of natural gas into its LNG facility, mostly from Algeria and Egypt. In 2005, Independence Station consumed 21,653 million cubic feet of natural gas for power generation purposes, an undetermined amount of which originated from the Lake Charles LNG Facility.

C.8. Biodiesel

In early 2007, approximately 400 public and federal fueling stations across the country offered biodiesel blends of B20 through B100 (GAO 2007). The number of fueling stations that offered biodiesel increased by an average of about 186 per year between 2004 and 2006. Despite this rapid increase, it is estimated that the number of fueling stations that offered biodiesel was only about 1 percent of the total number of fueling stations that offered diesel. Biodiesel fueling stations are dispersed nationwide because production facilities are not concentrated in any specific region.

Biodiesel is primarily transported by rail, but also by truck and barge. Limited capacity in this distribution system has led to supply disruptions and concerns about the system’s ability to effectively transport greater amounts of biodiesel if production significantly increases.

The bulk of the data relating to producers and distributors of biodiesel was compiled from the National Biodiesel Accreditation Program (NBAP), which is a cooperative and voluntary program for the accreditation of producers and marketers of biodiesel fuel called BQ-9000. The program is a unique combination of the ASTM standard for biodiesel, ASTM D 6751, and a quality systems program that includes storage, sampling, testing, blending, shipping, distribution, and fuel management practices. To receive accreditation, companies must pass a rigorous review and inspection of their quality control processes by an independent auditor. This ensures that quality control is fully implemented. On further investigation, the number of potential producers of biodiesel is significantly higher than the information presented by the NBAP. This, however, is attributed to the voluntary nature of the organization and admission requirements that producers meet the ASTM standard BQ-9000 quality and grade for the product.

The highest concentrations of biodiesel production and distribution networks for that grade are predominantly located in the Midwest clustering along the agrarian belt. Figure C-12 also indicates that the locations where agricultural products are produced and shipped from in order to help fuel the industry.

Source: National Biodiesel Board 2009.

Figure C-12. National Biodiesel Board Member Fuel Producers/Marketers

Most of the NBAP accredited companies are capable of supplying biodiesel anywhere in the country. In addition, the proximity of the potential biodiesel usage in relation to a company's listed mailing address is not necessarily relevant to its supply logistics or price structure. Some of these companies may not be actively producing biodiesel consistently on a national scale. It is more likely that production, distribution, and capacity in the NESCAUM states is limited when a comparison is made between the production and distribution capability of the New England region with that of the Midwest. Fortunately, the infrastructure needed to get biodiesel to consumers is emerging at a rapid pace. Currently, there are several suppliers of biodiesel, approximately twenty blenders and distributors of biodiesel, and a similar number of biodiesel retail fueling sites in New England. Some organizations with capital and commitment to the environment are building their own infrastructure to support biodiesel use. For example, in 2003, Harvard University spent $60,000 to build a state-of-the-art campus fueling station in Boston. Harvard is currently fueling its fleet of 48 diesel vehicles, including 8 shuttle buses, with B20.

Currently, the impetus for the use of biodiesel in the New England region has been sustained throughout the region by institutions, municipalities, and state-run agencies that have established and funded their own production and distribution capabilities. Biodiesel is being used throughout New England in a number of locations including: Connecticut Department of Transportation; L.L. Bean, Inc.; Maine Department of Transportation; City of Bangor, Maine; Harvard University; UMASS Amherst; NSTA; Medford, MA; Cambridge, MA; Brookline, MA; Mount Cranmore Ski Resort; New Hampshire Department of Transportation; Keene State College and the City of Keene, NH; Pease Air Force Base; Warwick, RI; University of Vermont; Vermont Law School; Sugarbush Ski Resort; and Vermont Coffee Company.

Below, Figure C-13 is an example of the production and distribution capabilities of the State of Vermont which is actually typical of most states within the NESCAUM region. In addition, the map below indicates that Vermont has rudimentary infrastructure for the distribution of biodiesel for mass consumption. However, the distribution of biodiesel is limited to specific small intra-state markets for residential heating and commercial businesses.

Source: Vermont Biodiesel Project 2007.

Figure C-13. Locations of Biodiesel Distributors in Vermont

Table C-19. Locations of Biodiesel Providers in Vermont

Business Name	Address	City	State	Zip	Phone
For Delivery					
BioQuantum, Inc.	P.O. Box 99	Perkinsville	VT	05151	(800) 901-2616
Bourne's Inc.	171 Bridge Street	Morrisville	VT	05661	(800) 326-8763
Champlain Oil Company	45 San Remo Drive	South Burlington	VT	05407	(802) 864-5380
Champlain Valley Plumbing & Heating	125 Monkton Road	Bristol	VT	05443	(802) 453-2325
D&C Transportation Inc.	32 Railroad Avenue	Orleans	VT	05860	(802) 754-6664
Dog River Alternative Fuels	1701 Chase Road	Berlin	VT	05602	(802) 229-4148
Dorr Oil Company	209 Riverside Heights	Manchester Center	VT	05255	(802) 362-1950
Fleming Oil Company	One Putney Road	Brattleboro	VT	05301	(802) 254-6095
Jack Corse Co.	5812 Vermont Route 15	Jeffersonville	VT	05464	(802) 644-2749
Owner Services, Inc.	41 School Street	Proctor	VT	05765	(802) 747-4987
Patterson Fuels	Route 117	Richmond	VT	05477	(800) 427-WARM
Rymes Heating Oils, Inc.	P.O. Box 2948	Concord	NH	03302	(603) 228-2224
Simple Energy	99 North Main Street	West Lebanon	NH	03784	(603) 298-7200
At The Pump					
Business Name	Address	City	State	Zip	Phone
Boise Citgo	3039 VT Route 22A	Bridport	VT	05734	(802) 758-2361
Dan and Whit's General Store	319 Main Street	Norwich	VT	05055	(802) 649-1602
Fleming's Shell Food Mart	429 Canal Street	Brattleboro	VT	05301	(802) 254-9727
Hart and Mead Texaco	234 Commerce Street	Hinesburg	VT	05461	(802) 482-2318
Lucky Spot Variety	174 River Road	Richmond	VT	05477	(802) 434-2332
On the Run Mobil	555 Fairfax Road	St. Albans	VT	05478	(802) 527-9932
Portland Street Valero	757 Portland Street	St. Johnsbury	VT	05819	(802) 748-1943
Steve's Citgo	3171 Ethan Allen Highway	Charlotte	VT	05445	(802) 425-2741
For Delivery & At The Pump					
Business Name	Address	City	State	Zip	Phone
Calkins Oil & Excavating, Inc.	36 Route 2 West	Danville	VT	05828	(802) 684-3375
Cota & Cota	4 Green Street	Bellows Falls	VT	05101	(802) 463-9150
Energy Co-op of Vermont	73 Prim Road, Suite 3	Colchester	VT	05446	(866) 626-4328
Evans Group of Vermont	171 Bridge Street	White River Junction	VT	05001	(800) 258-7552
Green Technologies Inc.	150 W. Canal Street	Winooski	VT	05404	(802) 655-1995
Hugh Duffy Coal & Oil Company Inc.	190 West Street	Rutland	VT	05701	(802) 773-2567
Jackman's Inc.	32 Pine Street	Bristol	VT	05443	(802) 453-2381

Source: Vermont Biodiesel Project 2007.

Appendix D: Supporting Data and Methods for Analysis of Regional Low Carbon Fuel Supply

Appendix D: Supporting Data and Methods for Analysis of Regional Low Carbon Fuel Supply

This Appendix provides detailed descriptions of data and methods used to generate the estimates of regionally available biomass. It also estimates the potential production of low carbon fuels, including electricity, presented in Chapter 5 of this report. Descriptions of data and methods are provided for estimates of biomass in the following order: woody biomass, agricultural biomass, and waste-based biomass. This Appendix then describes the methods and assumptions used to estimate quantities of low carbon fuels generated by converting different types of biomass into solid and liquid fuels. The final section of this Appendix explains, in detail, an analysis of electricity as a low carbon fuel for transportation. This includes estimates of the impacts of electric vehicles on the region's electric generating capacity and GHG emissions.

D.1. Woody Biomass Data and Methods

As described in Chapter 5, recent research evaluating the GHG impacts of biofuels has raised concerns that demand for biofuels may be creating impacts in global markets for land and bio-feedstocks. It is also a concern that this demand may increase net GHG emissions. To reduce the risk that a regional LCFS would create a significant increase in demand for feedstocks, this analysis considers woody biomass resources available after excluding woody biomass products currently being supplied to markets.

As shown in Figure D-1 below, the Northeast has significant existing markets for biomass and other low-grade wood. Major sources of market demand for low-grade wood include pulp mills, biomass electric facilities, oriented strand board (OSB) factories, medium density fiberboard manufacturers, thermal energy users (e.g., schools and hospitals), sawmills, pellet production facilities, and others.

The volume of woody biomass currently used in existing low-grade wood markets is estimated at 28.1 million green tons per year (4.4 million green tons per year in the Mid-Atlantic, and 23.7 million green tons in New England). If some of the facilities in this market were to close or decrease operations, additional woody biomass could potentially be available for other uses. These other uses may include electricity production, thermal energy, and transportation fuel production.

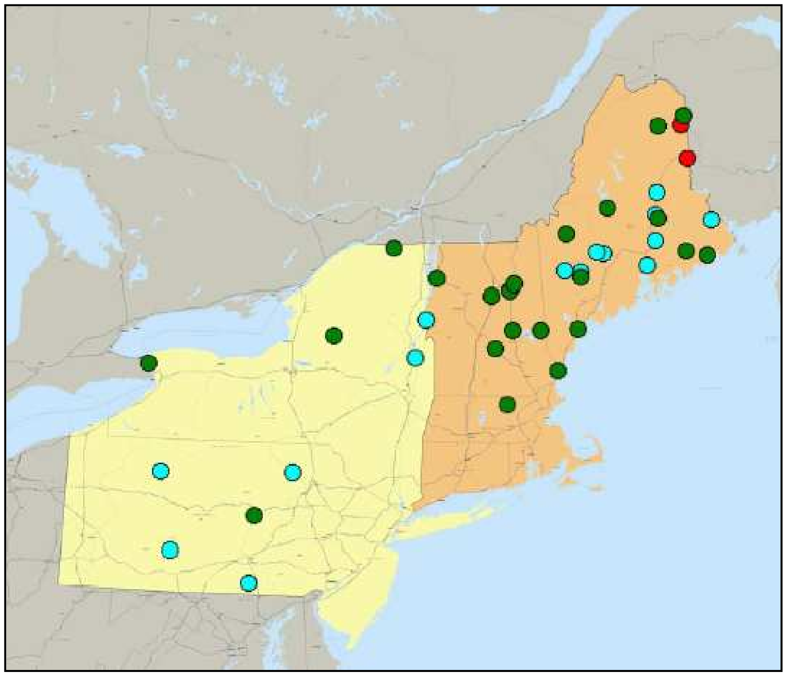


Figure D-1. Existing Northeast Markets for Biomass and Low-Grade Wood
Pulp Mills, Biomass Electric Plants and OSB Plants

Woody biomass is an aggregate description that represents numerous categories of biomass types. Not all woody biomass is appropriate for every end-use or technology. Below are detailed descriptions of each category of woody biomass included in Chapter 5. These include data sources, methods, and most typical end-uses for each category of biomass.

D.2. Forest residues

Forest residues include the otherwise unused portion of a harvested tree (e.g., branches, tops, or areas with splitting or rotting sections of wood) after the most valuable portion of the tree, the straight, lower section, is harvested for lumber, paper, or pulp markets. Logs are brought to a log landing, where the high-value portions of a tree are separated from the parts that are "off-spec," and forest residue is piled separately. Residues can be chipped directly into a logging truck, for direct delivery to market. Forest residues tend to be mixed species, as all residues on the log landing can be chipped and co-mingled. Because forest residues tend to have a high number of pieces that are oversized or otherwise not in conformance with traditional biomass specifications, forest residues are generally used at large biomass electricity plants or combined heat and power facilities (e.g., the energy plant at a pulp mill) that can screen and reprocess biomass chips.

INRS developed a national county-level database of estimated volumes of forest residues using the following sources:

- National Renewable Energy Laboratory – U.S. Department of Energy (NREL 2005);
- USDA Forest Service – Timber Product Output USDA (USDAFS 2007);
- Annual timber harvest volumes compiled by a number of individual states.

Forest residues are more concentrated in New England (particularly northern New England) and in southern and western Pennsylvania. This is because of the relatively high harvest volumes being generated by the wood-based industries located there. Residues are harvested directly from the woods and are generally available to market in "green" form, or roughly 45 percent moisture content.

Assuming that all forest residues not being used in existing markets are available for low carbon fuel applications, there are approximately 12 million green tons of forest residue in the region annually. However, we conservatively assume that only 20 percent of this quantity is used for low carbon fuel production. Because of a variety of physical and economic conditions (e.g., remote forest locations, landowner preferences) as well as environmental considerations, much of this forest residue would not be utilized. Based on this assumption, we estimate that the likely availability of forest residues available for low carbon fuel applications is 2.4 million green tons. Table D-1 below shows estimated quantities of forest residues, both maximum and likely availability.

Table D-1. Estimated Forest Residues, Maximum and Likely Availability

Maximum Availability	**(green tons)**
New England	7,400,000
Mid-Atlantic	4,600,000
Total	**12,000,000**
Likely Availability	**(20% of Maximum)**
New England	1,480,000
Mid-Atlantic	920,000
Total	**2,400,000**

The most likely fuel applications for forest residues include electricity production in biomass electricity plants and combined heat and power plants, and thermal energy (e.g., wood pellets for pellet stoves and boilers). Over the longer term, forest residues may be a suitable feedstock for some liquid transportation fuels.

D.3. Sawmill residues

Sawmill residues, including bark, sawdust, and mill chip, are produced when sawmills cut cylindrical logs into rectangular boards. Actual residue generation varies by species and mill equipment, but a general rule is that a sawmill log produces 60 to 70 percent of useful timber as boards, 20 to 30 percent as wood chips, and 10 percent as sawdust. Due to high concentrations of wood from the outer portion of the tree (which carries water from the roots to the leaves), sawmill residues are often high in moisture content (i.e., 50 percent). Sawmill residue can be used as a biomass fuel, but is often sought for other uses such as landscaping and animal bedding.

INRS's county-level database includes estimates of sawmill residue available on an annual basis. This database utilizes data developed by a number of sources, including:

- National Renewable Energy Laboratory – U.S. Department of Energy (NREL 2005);
- USDA Forest Service – Timber Product Output (USDAFS 2007);
- Mill production data from the U.S. Census Bureau, Manufacturing, Mining & Construction Division (U.S. Census Bureau 2007); and
- Annual sawmill production volumes compiled by a number of individual states.

Assuming that all sawmill residues not being used in existing markets are available for low carbon fuel applications, there are approximately 7.4 million green tons of forest residue in the region. The same assumption, that only 20 percent of this quantity is used for low carbon fuel production due to other factors and conditions, is applied. Based on this assumption, we estimate that the likely availability of forest residues for low carbon fuel applications is 1.5 million green tons. Table D-2 below shows estimated quantities of sawmill residues, both maximum and likely availability.

Table D-2. Sawmill Residues, Maximum and Likely Availability

Maximum Availability	**(in green tons)**
New England	2,990,000
Mid-Atlantic	4,390,000
Total	**7,380,000**
Likely Availability	**(20% of Maximum)**
New England	598,000
Mid-Atlantic	878,000
Total	**1,476,000**

D.4. Secondary mill residues

Secondary forest product residues are by-products of manufacturing consumer-ready material from lumber. Manufacturers that buy lumber (as contrasted with buying logs) and create a consumer-ready product – for example furniture, pallets, or factory-made housing – are part of the secondary forest products industry. They generally do not buy wood directly from loggers, foresters, or landowners. Instead, they rely upon brokers, both local and distant, to provide lumber as a raw material to their manufacturing process. The residue created at these facilities – shavings, sawdust, chips, and cut-offs – is an excellent source of biomass fuel. Because the raw material is purchased as lumber, and is generally kiln-dried, secondary forest product residues are a low-moisture content fuel, and have a higher heating value per ton than green wood fuels.

Estimated quantities of secondary mill residues, shown in Table D-3 below, are substantially lower than forest and mill residues. Assuming that all secondary mill residues are available, approximately 0.5 million tons are available. However, applying an assumption that only 40 percent of these resources would be available, we estimate that 0.2 million tons would be available for low carbon fuel applications.

Table D-3. Secondary Mill Residues, Maximum and Likely Availability

Maximum Availability	**(in dry tons)**
New England	140,000
Mid-Atlantic	330,000
Total	**470,000**
Likely Availability	**(40% of Maximum)**
New England	56,000
Mid-Atlantic	132,000
Total	**188,000**

D.5. Urban Wood Residues

Urban wood residues include most wood generated as a result of activity in and around urban and suburban areas, and include utility right-of-way clearing, used pallets and shipping crates, tree trimmings from street and yard trees, and the woody fraction of construction and demolition (C&D) debris. The components of urban wood vary by location, season, and economic cycle, but the woody fraction of C&D debris is generally around 40 percent of the urban wood stream.

INRS's database of urban wood residue was developed using data from a number of sources, including:

- National Renewable Energy Laboratory – U.S. Department of Energy (NREL 2005);
- U.S. Environmental Protection Agency waste generation estimates (USEPA 2007); and
- State-based estimates of construction and demolition debris.

In 2006, NESCAUM performed an analysis of the current C&D wood being processed and used to fuel wood boilers in New England and southern New York. The study indicated that there were 14 large wood boilers utilizing C&D wood as fuel within the study boundaries, producing almost 4.6 million MWh annually (NESCAUM 2006). The NESCAUM study used the definition employed at C&D processing sites: pallets, plywood, spools, furniture scraps, mill residue, particleboard, painted wood, and demolition wood are considered clean and may be used for fuel chips. However, processors may handle treated wood differently depending on the composition of the waste and the amount of time spent sorting or "cleaning" the waste. NESCAUM reviewed data from the Maine Department of Environmental Protection, which determined that average wood chips from C&D wood contained 66 percent untreated wood, 20 to 26 percent fines, which are more likely to contain metals and dioxin, and 10 percent painted wood, pressure-treated wood, non-burnable materials, and plastic (NESCAUM 2006).

The estimated maximum availability of urban wood residues in the Northeast is 6.2 million dry tons. However, due to co-mingling of urban wood with other wastes, the diverse and diffuse nature of urban wood generation, and the challenges of separating urban wood from other parts of the waste stream, we consider the likely availability of urban wood wastes to be 20 percent of the estimated maximum, or 1.2 million dry tons. Table D-4 below shows the maximum and likely availability of urban wood residues.

Table D-4. Urban Wood Residues, Maximum and Likely Availability

Maximum Availability	**Dry Tons**
New England	1,640,000
Mid-Atlantic	4,590,000
Total	**6,230,000**
Likely Availability	**(20% of Maximum)**
New England	328,000
Mid-Atlantic	918,000
Total	1,246,000

D.6. Net Forest Growth

Net forest growth refers to the annual level of forest growth on timberland (i.e., forestland capable of growing wood and where timber can be legally harvested) above the annual harvest level. The net growth refers only to the “roundwood” portion of the tree, or the stem that can be used for biomass or a variety of other forest products. An increase in harvest of net forest growth would also cause an increase in residue availability. Net forest growth correlates to approximately 0.3 green tons of forest residues for each ton of roundwood harvested.

INRS estimated net forest growth of timberland on a per-county basis using the USDA’s *Forest Inventory and Analysis* (FIA) tool, a resource on national trends in timber growth and harvest. Based on USDA’s FIA tool, the maximum quantity of net forest growth in the region equals 27.5 million green tons of woody biomass. Considering the variety of factors that will limit the actual use of new forest growth, including ecological concerns, limits on the ability to economically gather all wood from a site, and landowner attitudes toward timber harvesting, among others, we assume that only 10 percent of this total will likely be available for low carbon fuel applications. As such, there is approximately 2.8 million green tons of woody biomass from net forest growth. Table D-5 shows maximum and likely availability of net forest growth in New England and the Mid-Atlantic.

Table D-5. Net Forest Growth, Maximum and Likely Availability

Maximum Available	Green Tons
New England	3,870,000
Mid-Atlantic	23,640,000
Total	**27,510,000**
Likely Available	**(10% of Maximum)**
New England	387,000
Mid-Atlantic	2,364,000
Total	**2,751,000**

D.7. Agricultural Biomass

The Northeast is no longer a major agricultural producer, so agricultural activity is not likely to be a major source of potential biomass for the region. However, a recent study evaluated the region's potential for growing energy crops on less productive crop and pasturelands not in use for food crops. This section describes data and methods used in this analysis.

D.7.1 Dedicated Energy Crops

Dedicated energy crops that could feasibly be grown on marginal land in the Northeast include short-rotation woody crops, such as hybrid poplar and hybrid willow, and herbaceous crops such as switchgrass. An analysis of the potential for the Northeast Biomass Regional Program (NRBP) considered switchgrass and short-rotation woody crops independently. It was assumed that switchgrass was grown only on Conservation Reserve Program lands, and therefore represents the maximum theoretical availability. Short-rotation woody crops were assumed to be grown on 25 percent of the unused farmland in the region that is not enrolled in the Conservation Reserve Program (Antares 2007). Table D-6 provides maximum totals for switchgrass and short-rotation woody crops, which together round up to 3.3 million dry tons per year. Assuming that only 50 percent of this would be available to markets for a variety of factors such as economic and environmental constraints, likely availability of energy crops is 1.6 million dry tons per year.

Table D-6. Estimated Maximum Energy Crop Potential, by State

(Thousand Dry Tons/Year)

State	Switchgrass	Short-Rotation Woody Crops
Connecticut	1.4	59.8
Maine	0	125.1
Massachusetts	.2	65.7
New Hampshire	0	45.1
New Jersey	11.8	121.6
New York	295.4	1,398.3
Pennsylvania	1.1	1,001.0
Rhode Island	0	8.5
Vermont	5.5	137.9
TOTAL	**315.4**	**2,963.0**

D.7.2 Waste-based Biomass

As discussed in Chapter 5, waste-based biomass is a unique feedstock in the Northeast. The region's dense population ensures that, even with continued supply of recyclables to existing markets and significant ramp-up of source reduction and recycling, there is likely to be a steady stream of organic waste in the region. Use of waste-based biomass may alleviate concerns about use of virgin biomass feedstocks and the associated indirect land use changes and may result in avoided emissions as waste is managed closer to the source, rather than transported outside the region.[72] Table D-7 shows the percentages of MSW that are landfilled versus exported out of state for each of the northeastern states.

[72] Due to high tipping fees and limited space for new landfills, much of the Northeast's waste is exported out of the region. The weighted average transport distance by state of MSW exported for out-of-state disposal was determined using destination data provided by the Congressional Research Service's *Report for Congress*: *Interstate Shipment of MSW* (McCarthy 2007). The destination of exported wastes was provided in total tonnage by state, which was converted to a percent exported to determine the weighted average transport distance. The transport distance from one state to another was determined by using the web-based Google Earth program to determine the driving distance from the generating state's capital to the destination state's largest landfill, as determined by WasteNews' compilation of the largest landfills.

Table D-7. Management of Northeastern MSW, By State

State	Waste Managed Instate			Waste Exported	
	Percent	Percent Landfilled	Percent Combusted	Percent	Average Distance (weighted)
CT	82.5%	28%	72%	17.5%	332 miles
ME	99.7%	42%	58%	0.3%	126 miles
MA	77.5%	69%	31%	22.5%	650 miles
NH	99.5%	73%	26.98%	11.5%	178 miles
NJ	72.1%	75%	25%	27.9%	136 miles
NY	61.6%	77%	23%	38.4%	329 miles
PA	97.8%	not available	not available	2.2%	340 miles
RI	94.4%	100%	0%	5.6%	586 miles
VT	85.9%	86%	14%	14.1%	227 miles

In this report, waste-based biomass is used to define refuse that is organic in origin and becomes available after primary use and all economically and environmentally beneficial options for disposal have been exhausted. The organic portion of MSW, including yard waste, food waste, and paper waste, used cooking oils, biosolids from livestock, and biosolids and biogas from wastewater treatment facilities were considered. The following section describes how maximum and likely volumes for each category were determined.

D.7.3 Municipal Solid Waste

To estimate MSW-based biomass volumes, waste data for each of the northeast states was retrieved from state published data and a 2006 survey of waste production by state (Simmons *et al.* 2006).[73] Depending on availability of data for years 2004 to 2006 for each state, two to three years of data were averaged to estimate total waste in 2005. Waste characterization tables in EPA's *Municipal Solid Waste Generation Facts and Figures for 2006* (EPA 2006) were used to determine the organic portion by category (yard waste, paper, food waste, wood scraps) and type. The breakdown of yard waste into 50 percent grass, 25 percent brush, and 25 percent leaves was taken from EPA's *Municipal Solid Waste in the United States: 2005 Facts and Figures* (EPA 2007). Some states and cities, including Pennsylvania, Vermont, and New York City, have conducted their own waste characterizations. The results from these studies are compared in Table D-8 to the EPA assumptions used in this report.

[73] Waste data for 2004 were retrieved from Simmons *et al.* 2006. Waste data for 2005 and 2006 were taken from state MSW plans and other relevant publications available on state environmental agency websites.

Table D-8. Comparison of National and State Waste Studies

	EPA	PA	NYC	VT-Com	VT- Res
Paper	33.9%	33%	29.6%	20.7%	28.1%
Organics (incl. Food/Yard Waste)	30.8	34.3%	38.9%	37.1%	22.0%
Total Waste Characterized	99.9%	99.7%	92.9%	95.4%	86.7%

Sources: PADEP 2001, DSNY Bureau of Waste Prevention 2007, DSM Environmental Services 2002.

To determine a per capita feedstock estimate for each category of organic waste, 2005 population data from the U.S. Census Bureau were used for each state. Population projections for each state in 2010 and 2020, provided in Table D-9, were then used to estimate future waste totals, assuming that waste totals increase commensurate with the rate of population growth.

Table D-9. Population Estimates for Northeast, 2005 to 2030

	Population			
	2005	**2010**	**2020**	**2030**
New England	***14,372,985***	***14,738,789***	***15,309,528***	***15,623,015***
Maine	1,318,557	1,357,134	1,408,665	1,411,097
New Hampshire	1,314,821	1,385,560	1,524,751	1,646,471
Vermont	630,979	652,512	690,686	711,867
Massachusetts	6,518,868	6,649,441	6,855,546	7,012,009
Rhode Island	1,086,575	1,116,652	1,154,230	1,152,941
Connecticut	3,503,185	3,577,490	3,675,650	3,688,630
Mid-Atlantic	***40,429,964***	***41,046,390***	***41,825,909***	***42,048,053***
New York	19,258,082	19,443,672	19,576,920	19,477,429
New Jersey	8,745,279	9,018,231	9,461,635	9,802,440
Pennsylvania	12,426,603	12,584,487	12,787,354	12,768,184
Northeast	**54,802,949**	**55,785,179**	**57,135,437**	**57,671,068**

Source: U.S. Census Bureau 2008.

Based on the methodology described above, Table D-10 provides an estimate of organic municipal waste by category and type for 2010, 2020, and 2030. The maximum availability does not include any of the cardboard and office paper disposed in the region, relying on the assumption that 100 percent is used in existing markets. The likely availability for the organic portion of MSW was estimated at 50 percent.

Table D-10. Estimated Quantity of Organic MSW in Northeast, 2010 to 2020

Maximum Availability			
	Biomass Quantity (Tons)		
Biomass Type	**2010**	**2020**	**2030**
Yard Waste	5,506,063	5,595,848	5,665,064
Paper	18,856,381	19,163,864	19,400,904
Wood Scraps	4,982,779	5,063,959	5,125,240
Food Scraps	12,822,339	13,031,427	13,192,615
TOTAL	66,492,294	67,576,482	68,410,989
Likely Availability			
	Biomass Quantity (Tons)		
Biomass Type	**2010**	**2020**	**2030**
Yard Waste	2,753,032	2,797,924	2,832,532
Paper	9,428,191	9,581,932	9,700,452
Wood Scraps	2,491,390	2,531,980	2,562,620
Food Scraps	6,411,170	6,515,714	6,596,308
TOTAL	20,390,809	20,723,277	20,978,928

D.7.4 Waste Oils

Waste oil is the spent oil from restaurant fryalators (“yellow”) and grease traps (“brown”). Most waste oil is currently collected, following an effort by northeastern states to prevent used oil from entering into municipal sewage systems. Today, waste oils have a variety of commercial uses, including the market for biodiesel from yellow grease, which requires little cleaning or processing of oil before conversion into diesel fuel (Cohen 2007). Yellow grease availability was calculated assuming that restaurants produce 9 pounds of yellow grease per person per year (Wiltsee 1998). Likely availability was estimated at 10 percent due to competing markets for waste oils. Table D-11 below summarizes the maximum and likely availability of waste oils, based on our assumptions.

Table D-11. Estimated Quantities of Waste Oils, 2010 to 2020

Maximum Availability		
	Biomass Quantity (Tons)	
Biomass Type	**2010**	**2020**
Used Cooking Oil “yellow”	251,033	257,109
Likely Availability		
	Biomass Quantity (Metric Tons)	
Biomass Type	**2010**	**2020**
Used Cooking Oil “yellow”	25,103	25,711

D.7.5 Agricultural Livestock Waste and Biosolids and Biogas from Wastewater Treatment Facilities (WWTF)

Waste solids from wastewater treatment facilities and livestock have an alternative use in the region as fertilizer. Biogas (methane) from many wastewater treatment facilities is already captured and flared or used to generate electricity. Solid livestock waste by livestock type and state were determined by using the U.S. Census Bureau's *2008 Statistical Abstract of the National Data Book* for cattle, pigs, and poultry (except laying chickens) and Iowa State's *Manure Production Assumptions* (Lorimor 2001). Data on the number of laying chickens by state was taken from the National Agricultural Statistics Service's *Chickens and Eggs* report (USDANASS 2008). Information on solid wastes and biogas generation per person was derived from the EPA's *Biosolids Generation, Use, and Disposal in the United States* (EPA 1999) and applied to the estimates of current and future population for each state. Likely availability is assumed to be 50 percent. Table D-12 summarizes our estimates of the maximum and likely availability of agricultural and wastewater biowaste for low carbon fuel production.

Table D-12. Estimated Quantities of Agricultural and Wastewater Biowaste, 2010 to 2020

Maximum Availability			
	Biomass Quantity (Metric Tons or Cubic Feet)		
Biomass Type	**2010**	**2020**	**2030**
Agricultural Livestock Waste (tons)	10,430,126	10,590,876	10,710,844
Wastewater Treatment Plant Biosolids (tons)	1,450,415	1,470,707	1,485,521
Wastewater Treatment Plant Biogas (cubic feet)	55,785,179	56,565,669	57,135,437
Likely Availability			
	Biomass Quantity (Metric Tons or Cubic Feet)		
Biomass Type	**2010**	**2020**	**2030**
Agricultural Livestock Waste (tons)	5,215,063	5,295,438	5,355,422
Wastewater Treatment Plant Biosolids (tons)	725,208	735,354	742,761
Wastewater Treatment Plant Biogas (cubic feet)	27,892,590	28,282,835	28,567,719

D.8. Electric Capacity for Plug-In Hybrid Electric Vehicles

Assumptions about PHEV penetration in the northeast states were calculated by applying national market share estimates reported by EPRI and NRDC (EPRI/NRDC 2007) to business-as-usual projections of vehicle stock from NE-Vision (NESCCAF 2008). The electricity requirements (kWh per year) associated with 20-mile and 40-mile all-electric ranges (AER) were based on EPRI and NRDC calculations, and assumed to be 1,840 kWh and 2,477 kWh, respectively. Table D-13 below summarizes the low and high projections of the number of vehicles entering the Northeast's market, as well as total electricity demand associated with this level of PHEV market penetration.

Table D-13. Potential PHEV Levels and Associated Electricity Demand for the Northeast

Vehicle Penetration Level	Vehicle Stock (number of vehicles)		Additional Electricity Demand (kWh per Year)	
	Baseline LDV	PHEVs 2020	20-mi AER	40-mi AER
Low	41,705,451	2,620,396	4,821,528,175	6,490,720,266
High		8,229,022	15,141,399,265	20,383,285,859

The analysis to assess the incremental effects of PHEV on the electric power systems in New England, New York, and the Mid-Atlantic was based on an evaluation of recent patterns of economic generation dispatch in these electricity grids. The load duration curve in Figure D-2 represents the order of dispatch of different generation resources over the course of one year. The number of hours of electricity generation in one year is displayed on the x-axis, and electricity load in mega-Watts (MW) on the y-axis. The dispatch order of generation is driven by marginal cost of operation for a given generation technology. (Wind and solar have intermittent output, but they are operated with other baseload generation because their marginal cost of operation is extremely low.)

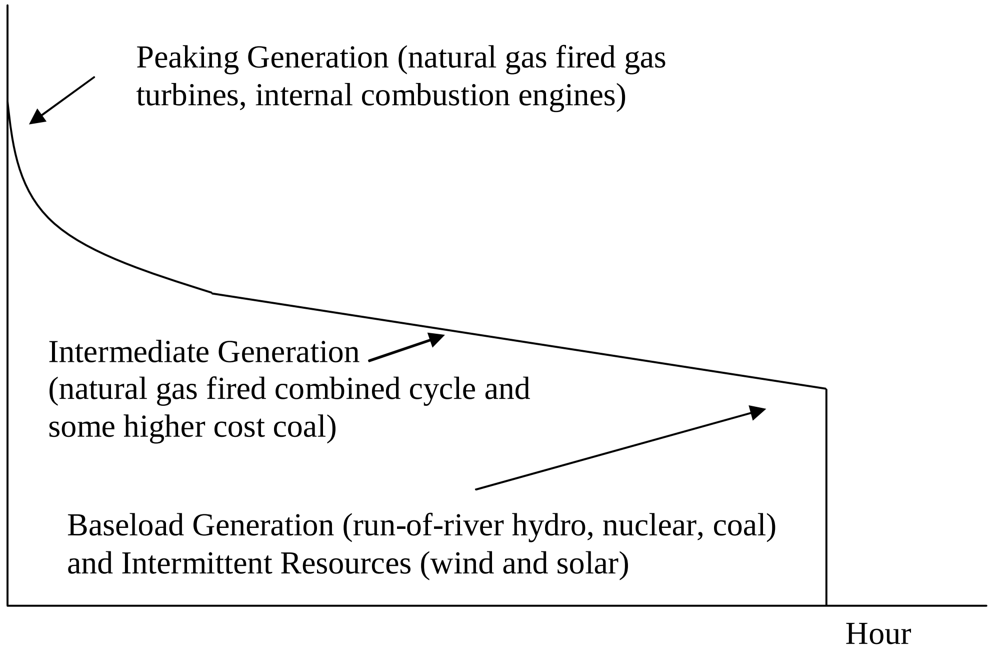


Figure D-2. Forecasted Peak Demand and Energy for New England, New York and PJM Mid-Atlantic

The load duration curve reflects that, in the New England, New York, and PJM power grids, excess generation capacity is available during many hours of the year, whereas extra capacity is needed during a more limited number of hours each year.

Therefore, in addition to vehicle penetration and AER, this analysis evaluated scenarios which varied the initial time of vehicle charging (i.e., when the vehicle is plugged in) and the charging duration (i.e., how long the vehicle charges). Workday (9 a.m.), after work (5 p.m.), and nighttime (12 midnight) charging times and 2-hour, 4-hour, and 6-hour charging durations were represented in different scenarios.

Other assumptions required for the analysis are estimated heat rates and emissions factors for baseload, intermediate, and peaking generation technologies represented in the load profiles for the three electricity grids affected. Table D-14 below shows the assumptions for heat rates and CO_2 emission factors for coal, natural gas combined cycle, and natural gas turbine generation units. Table D-15 displays the peak capacity of each grid, and annual electricity generation as well.

Table D-14. Generation Unit Heat Rates and Emission Characteristics

Unit Characteristic	Existing Coal	Existing Natural Gas Combined Cycle	Natural Gas Turbine
Heat Rate (BTU/kWh)	8,600	6,500	9,200
CO_2 Emissions (metric tons/MWh)	.90	0.35	0.50

Sources: The Brattle Group 2008, various publicly available resources, and industry knowledge.

Table D-15. Peak and Annual Electricity Generation Capacity in PJM, ISO-NE, and NY-ISO

	Peak (MW)			Annual Energy (GWh)		
	2010	2015	2020	2010	2015	2020
PJM Mid-Atlantic	145,413	155,988	167,217	307,893	331,437	355,144
ISO-NE	26,724	28,367	30,110	137,885	143,500	183,146
NYISO	31,251	32,748	34,316	166,996	174,994	183,375

Notes: GWh stands for giga-Watt-hours, which is a 1000 MWh
References: PJM: Load Forecast Report, May 2008 for Mid-Atlantic region (1.4%)
ISO-NE: CELT, 2008 (1.5%); 1.5% per year escalation from 2015 to 2020
NYISO: 2008 Load and Capacity Data Book; 2018-2020 escalated at same rate as from 2008-2018 (0.94%)

D.9. Results

The first requirement for determining the effects of PHEV on electric dispatch was to calculate the incremental hourly load for different scenarios. Table D-16 provides the incremental hourly load for various penetration, charging duration, and AER scenarios in 2010 and 2020.

Table D-16. Incremental Hourly Load (MW) for Different Charging Duration and AER Scenarios of Low and High Vehicle Penetration Rates for 2010 and 2020

		20-mi AER		40-mi AER	
		Low	High	Low	High
2010	**2-hour**	6,336	19,898	8,530	26,786
	6-hour	2,112	6,633	2,843	8,929
2020	**2-hour**	7,400	23,237	9,961	31,282
	6-hour	2,467	7,746	3,320	10,427

Because dispatch differs by time of day (simplified), it was then necessary to apply each of the incremental hourly load scenarios to different start times for charging, which loosely correspond to generation types. Figure D-3 illustrates three possible outcomes on grid requirements associated with PHEV charging on the load duration curve. The type of generation used to meet the incremental electricity demand due to charging of PHEV depends primarily on the time of day that charging occurs.

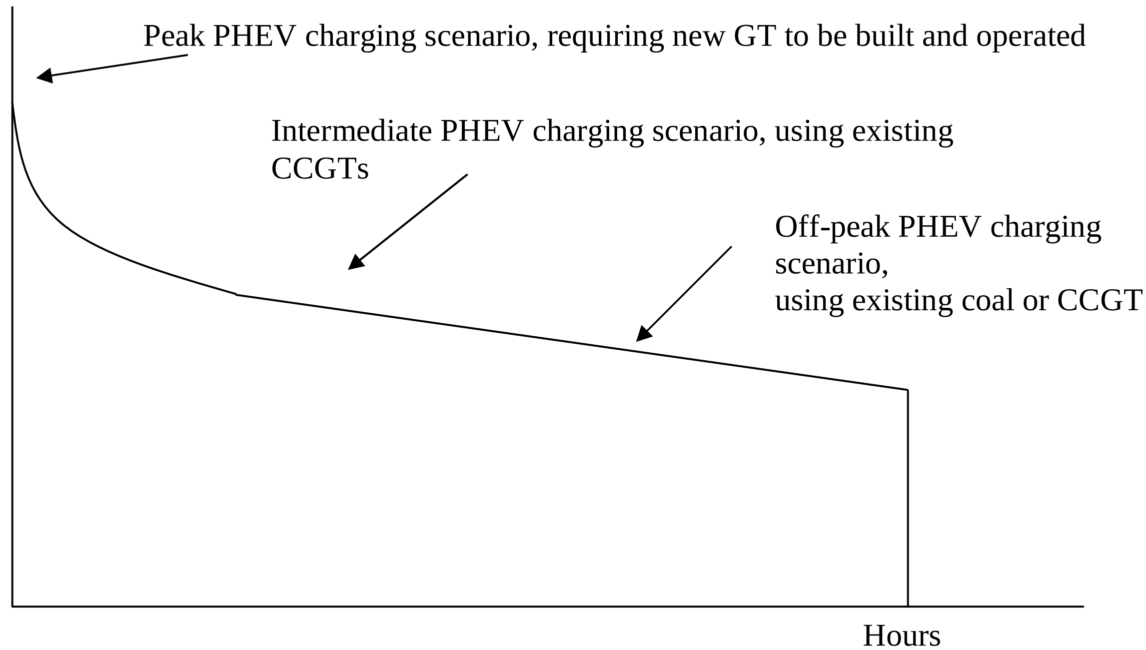


Figure D-3. Stylized Load Duration Curve Demonstrating Incremental Demand and Generation Due to PHEV SHAPE

Depending on charging time, charging duration, and vehicle penetration, some PHEV scenarios would require no additional electric generation capacity. Table D-17 provides a summary of the additional capacity necessary to meet PHEV electricity demand.

Table D-17. Capacity Remaining/ Required for each PHEV Electricity Demand Scenarios by Regional ISO ("-" indicates additional capacity required)

		2010			2015			2020		
		NE	**NY**	**PJM**	**NE**	**NY**	**PJM**	**NE**	**NY**	**PJM**
40 mi High 2 Hour Charge	**9am**	-2145	-102	11162	-2486	-392	11713	-2706	-571	12581
	5pm	-6984	-6585	-12066	-7623	-7186	-13188	-8158	-7595	-14112
	12am	562	-415	20450	387	-720	21669	344	-915	23254
40 mi High 4 Hour Charge	**9am**	1375	3191	17744	1354	3201	18894	1404	3274	20267
	5pm	-3465	-3292	-5485	-3782	-3593	-6006	-3783	-3750	-6426
	12am	4082	2877	27031	4228	2872	28851	878	2930	30940
40 mi High 6 Hour Charge	**9am**	2548	4288	19937	2634	4399	21288	2774	4556	22829
	5pm	-2291	-2195	-3291	-2502	-2395	-3612	-2678	-2469	-3864
	12am	5255	3975	29225	5508	4070	31244	5824	4212	33502
40 mi Medium 2 Hour Charge	**9am**	-376	1553	14470	-556	1414	15322	-641	1362	16444
	5pm	-5215	-4930	-8758	-5693	-5380	-9578	-6093	-5663	-10249
	12am	2331	1240	23758	2317	1085	25278	2410	1017	27117
40 mi Medium 4 Hour Charge	**9am**	2259	4018	19397	2319	4104	20699	5514	4240	22199
	5pm	-2580	-2465	-3831	-2817	-2690	-4201	62	-2784	-4494
	12am	4966	3705	28685	5193	3775	30655	8564	3896	32872
40 mi Medium 6 Hour Charge	**9am**	2548	4288	19937	2634	4399	21288	2774	4556	22829
	5pm	-2291	-2195	-3291	-2502	-2395	-3612	-2678	-2469	-3864
	12am	5255	3975	29225	5508	4070	31244	5824	4212	33502
40 mi Low 2 Hour Charge	**9am**	2653	4387	11162	189	4506	21502	2896	4671	23058
	5pm	-2187	-2097	-12066	-4948	-2288	-3398	-2556	-2354	-3635
	12am	5360	4073	20450	3062	4177	31458	5947	4326	33731
40 mi Low 4 Hour Charge	**9am**	3773	5435	22229	3972	5650	23789	5514	5895	25506
	5pm	-1066	-1048	-999	-1165	-1144	-1111	62	-1130	-1187
	12am	6480	5121	31517	6845	5321	33745	8564	5550	36179
40 mi Low 6 Hour Charge	**9am**	4147	5784	22928	4380	6031	24551	4642	6303	26321
	5pm	-692	-699	-301	-757	-763	-349	-811	-721	-372
	12am	6854	5471	32215	7253	5703	34508	7692	5959	36994
20 mi High 2 Hour Charge	**9am**	-335	1592	14547	-511	1456	15406	-592	1407	16535
	5pm	-5174	-4892	-8681	-5647	-5338	-9494	-6044	-5618	-10158
	12am	2372	1278	23835	2363	1128	25363	2458	1062	27207
20 mi High 4 Hour Charge	**9am**	2280	4038	19436	2342	4125	20741	5514	4263	22244
	5pm	-2559	-2446	-3792	-2795	-2669	-4159	62	-2761	-4449
	12am	4987	3724	28724	5215	3796	30697	8564	3919	32917
20 mi High 6 Hour Charge	**9am**	3151	4853	21066	3293	5015	22519	3479	5215	24147
	5pm	-1688	-1631	-2163	-1844	-1779	-2381	-1974	-1809	-2546
	12am	5858	4539	30353	6166	4686	32476	6529	4871	34820
20 mi	**9am**	979	2821	17004	923	2798	18088	942	2842	19404

Medium 2 Hour Charge	**5pm**	-3860	-3662	-6224	-4214	-3996	-6813	-4510	-4182	-7289
	12am	3686	2507	26292	3796	2469	28044	3992	2498	30077
20 mi Medium 4 Hour Charge	**9am**	2937	4652	20665	3059	4796	22082	5514	4981	23679
	5pm	-1902	-1831	-2564	-2078	-1998	-2819	62	-2044	-3014
	12am	5644	4339	29952	5932	4467	32038	8564	4636	34351
20 mi Medium 6 Hour Charge	**9am**	3589	5263	21885	3771	5462	23413	3990	5694	25103
	5pm	-1250	-1221	-1344	-1366	-1332	-1487	-1462	-1331	-1590
	12am	6296	4949	31172	6644	5133	33369	7040	5349	35776
20 mi Low 2 Hour Charge	**9am**	3229	4926	21211	3378	5094	22678	3570	5300	24317
	5pm	-1610	-1558	-2017	-1759	-1700	-2222	-1883	-1724	-2376
	12am	5936	4612	30499	6251	4766	32635	6620	4956	34990
20 mi Low 4 Hour Charge	**9am**	4062	5705	22768	4286	5944	24377	4542	6210	26135
	5pm	-778	-779	-460	-850	-850	-523	-910	-815	-558
	12am	6769	5391	32056	7160	5615	34333	7592	5865	36808
20 mi Low 6 Hour Charge	**9am**	4339	5964	23287	4589	6227	24943	4866	6513	26741
	5pm	-500	-519	59	-547	-567	43	-586	-511	48
	12am	7046	5651	32575	7463	5899	34900	7916	6169	37414

This analysis is necessarily limited by the ability to forecast many factors, including: the timing, degree, and elements of greenhouse gas and other emission reduction policies; future electric power generation costs and performance of conventional and renewable technologies, particularly relative costs and performance; input fuel prices such as uranium, coal, natural gas and oil; transmission expansions and associated policies; development of plug-in hybrid charging stations and associated policies; and peak versus off-peak load growth. Therefore, this analysis should be viewed as a possible range of outcomes with associated policy variables that only begin to reveal the policy adjustments needed to reduce the cost and emissions associated with using the electric grid to fuel the transportation system.

Current state policies in the region would affect the impact PHEVs have on air emissions. All three regions, or parts thereof, have cap-and-trade policies for nitrogen oxides and sulfur dioxide and are implementing the Regional Greenhouse Gas Initiative (RGGI), which caps carbon dioxide emissions from generation units 25 MW and greater. If the number of allowances for these air emissions is not increased to account for emissions from existing or added generation (if needed) associated with PHEVs, then the incremental emissions from the region will be zero. There may be incremental emissions from bordering states not subject to these caps, since electricity may be imported into the region. The impact of PHEVs, under this scenario, could put price pressure on the prices of allowances, resulting in higher allowance prices combined with more construction of low and zero air emission generation facilities than would otherwise occur. Estimating these possible increases in emission allowance prices and changes in future generation investment due to PHEVs is beyond the scope of this report.

The three regions also have energy efficiency and renewable energy policies that may or may not be modified in conjunction with a possible PHEV policy. If additional energy efficiency and renewable energy investments are tied to the additional demand PHEVs impose upon the electric grid, the incremental effects of PHEVs would be lessened. In addition, all three regions are implementing efforts to reduce peak demand, which flattens the load duration curve.

There are also uncertainties beyond the effects of PHEVs on the electrical grid. The location that charging occurs will affect transmission and distribution systems. For example, additional transmission and distribution investments may be required if commuters to cities such as New York or Boston charge during the day. Substantial transmission constraints exist in the greater Boston, New York City/Long Island and northeastern portion of New Jersey (Potomac Economics, LTD 2007).

In 2007, major interfaces in the New York City load pocket were congested 20 percent of the time. Constraints in New York City and Long Island along with local load pockets were substantial enough to raise prices in these zones (Potomac Economics, LTD 2007). In the case of the PJM Mid-Atlantic, northern New Jersey incurred over $200 million in congestion costs in 2007 (PJM Interconnection 2007). The constraints in Boston require less immediate attention, but could cause concern in a high-penetration PHEV scenario.