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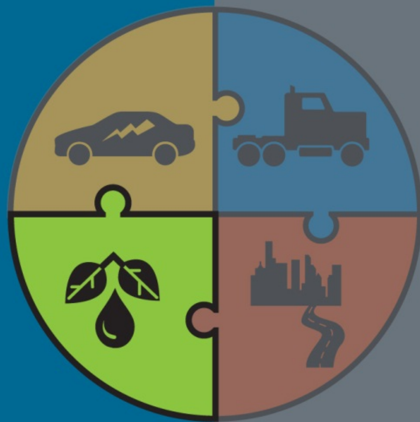

FUELS

Alternative Fuel Infrastructure Expansion: Costs, Resources, Production Capacity, and Retail Availability for Low-Carbon Scenarios

TRANSPORTATION ENERGY FUTURES SERIES:

Alternative Fuel Infrastructure Expansion: Costs, Resources, Production Capacity, and Retail Availability for Low-Carbon Scenarios

A Study Sponsored by
U.S. Department of Energy
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Prepared by
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managed by
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About The Transportation Energy Futures Project

This is one of a series of reports produced as a result of the Transportation Energy Futures (TEF) project, a U.S. Department of Energy (DOE)-sponsored multi-agency project initiated to identify underexplored strategies for abating greenhouse gases (GHG) and reducing petroleum dependence related to transportation. The project was designed to consolidate existing transportation energy knowledge, advance analytic capacity-building, and uncover opportunities for sound strategic action.

Transportation currently accounts for 71% of total U.S. petroleum use and 33% of the nation's total carbon emissions. The TEF project explores how combining multiple strategies could reduce GHG emissions and petroleum use by 80%. Researchers examined four key areas – light-duty vehicles, non-light-duty vehicles, fuels, and transportation demand – in the context of the marketplace, consumer behavior, industry capabilities, technology and the energy and transportation infrastructure. The TEF reports support DOE long-term planning. The reports provide analysis to inform decisions about transportation energy research investments, as well as the role of advanced transportation energy technologies and systems in the development of new physical, strategic, and policy alternatives.

In addition to the DOE and its Office of Energy Efficiency and Renewable Energy, TEF benefitted from the collaboration of experts from the National Renewable Energy Laboratory and Argonne National Laboratory, along with steering committee members from the Environmental Protection Agency, the Department of Transportation, academic institutions and industry associations. More detail on the project, as well as the full series of reports, can be found at http://www.eere.energy.gov/analysis/transportationenergyfutures.

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Participants in an initial Transportation Energy Futures scoping meeting in June 2010 – representing the U.S. Department of Energy and national laboratories – assisted by formulating innovative and timely ideas to consider for the project. Steering Committee members and observers offered their thoughtful perspective on transportation analytic research needs as well as insightful comments on an initial Transportation Energy Futures work plan in a December 2010 meeting, and periodic teleconferences through the project.

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Acronym List

AEO	Annual Energy Outlook
BAU	business as usual
BEV	battery electric vehicle
BGGE	billion gallons of gasoline equivalent energy
BTS2	Billion Ton Study, 2011 update
Btu	British thermal unit
CCS	carbon capture and storage
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent greenhouse gases
DOE	U.S. Department of Energy
E10	ethanol-gasoline blend with approximately 10% ethanol by volume
E85	ethanol-gasoline blend with approximately 85% ethanol by volume
EIA	Energy Information Administration
EVSE	electric vehicle supply equipment
FCEV	fuel cell electric vehicle
FCI	fuel carbon intensity
FT	Fischer-Tropsch
gCO_2e	grams carbon dioxide equivalent
gge	gallon of gasoline equivalent
GHG	greenhouse gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (model)
HEV	hybrid electric vehicle
kWh	kilowatt-hours
LCOE	levelized cost of energy
LDV	light-duty vehicle
LNG	liquid natural gas
M/HDV	medium- and heavy-duty vehicles
MJ	megajoule
MDT	million dry short tons
$MMTCO_2e$	million metric tons of carbon dioxide equivalent
$MTCO_2e$	metric tons of carbon dioxide equivalent
mpgge	miles per gallon of gasoline equivalent
MSW	municipal solid waste
NACS	National Association of Convenience Stores
NLDV	non-light-duty vehicle
NPN	National Petroleum News
NREL	National Renewable Energy Laboratory
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
quad	quadrillion Btu
REF	Renewable Electricity Futures study
TEF	Transportation Energy Futures
TWh	terawatt-hour
VMT	vehicle miles traveled
VRI	Vehicle-to-Refueling Station Index
WTT	well to tank
WTW	well to wheels

EXECUTIVE SUMMARY

Fuels Infrastructure in Low-Carbon Scenarios

The petroleum-based transportation fuel system is complex and highly developed, in contrast to the nascent low-petroleum, low-carbon alternative fuel system. This report examines how expansion of the low-carbon transportation fuel infrastructure could contribute to deep reductions in petroleum use and greenhouse gas (GHG) emissions across the U.S. transportation sector. Three low-carbon scenarios, each using a different combination of low-carbon fuels, were developed to explore infrastructure expansion trends consistent with a study goal of reducing transportation sector GHG emissions to 80% less than 2005 levels by 2050.[1] This goal was for analytic purposes only. These scenarios were compared to a business-as-usual (BAU) scenario and were evaluated with respect to four criteria: fuel cost estimates, resource availability, fuel production capacity expansion, and retail infrastructure expansion.

Initial evaluations of these four criteria enable consideration of screening-level questions about fuel infrastructure in the low-petroleum, low-carbon scenarios:

1. How do alternative fuel costs compare to conventional fuel costs?
2. Are low-carbon resources sufficient?
3. How does expansion of alternative fuel production capacity compare to conventional production capacity replacements, upgrades, and expansion?
4. How do costs of providing alternative fuel retail infrastructure compare to conventional retail infrastructure?

Although definitive comparisons are not possible in this screening study, results suggest that expansion of the retail infrastructure for alternative fuels may pose greater issues than fuel costs, resources, or production capacity. The study does not address market barriers and transition costs associated with the development of new advanced vehicle and low-carbon fuel markets, so fuel cost estimates do not reflect investment risks or projected fuel prices. However, an evaluation of each scenario suggests that the goal of a reduction of 80% in GHGs can be reached while maintaining total fuel costs that are ultimately lower than BAU fuel cost projections without imposing excessive demands on energy resources such as biomass, natural gas, or renewable electricity systems.

The amount of new fuel production capacity required [e.g., billions of gallons of gasoline equivalent energy (BGGE) per year] in the low-carbon scenarios is comparable to those for conventional fuels in the BAU scenario, despite the transition to different fuels, because fuel demand in the low-carbon scenarios is lower. Expansion of retail infrastructure, on the other hand, may prove challenging in terms of spatial coverage and sustainable business models for retail outlets. Suggestions in the study for further analysis call for improved cost estimates, an improved understanding of the influence of refueling infrastructure on consumer vehicle purchase decisions, exploration of the potential role of public-private partnerships in infrastructure planning and expansion, and spatial and temporal market and infrastructure expansion trends.

[1] The term "infrastructure" refers to the complete fuel supply chain, including resource extraction and fuel production, storage, delivery, and dispensing.

Key Findings

Use of a variety of advanced low-carbon fuels can contribute to deep and long-term greenhouse gas and petroleum use reductions. Advanced biofuels play a major role in all low-carbon scenarios developed for this study, especially in non-light-duty vehicle market segments, while natural gas, electricity, and hydrogen play greater or lesser roles in the light-duty vehicle market segments of each particular low-carbon scenario. The combination of reductions in demand for transportation services (e.g., fewer vehicle miles traveled per person) and improvements in end-use efficiency (e.g., more efficient vehicles) can significantly reduce future demand for transportation fuels. These reductions are key to reducing total fuel expenditures, the use of low-carbon energy resources, the need for new fuel production capacity, and capital costs for retail fueling infrastructure.

- In the three low-carbon fuel scenarios developed for this study, low-carbon fuels account for approximately 35% of the overall 80% reduction in GHG emissions below 2005 levels by 2050, with efficiency improvements accounting for approximately 55% and demand reductions accounting for 10%.
- Overall fuel costs in the low-carbon scenarios are less than business-as-usual expenditures by $200 billion to $1,000 billion per year by 2050 [compared to fuel expenditures in the Low Oil price and High Oil price cases, respectively, in the 2011 *Annual Energy Outlook* (Energy Information Administration 2011)].
- Domestic biomass resources can make substantial contributions to a low-carbon transportation future. Within the low-carbon scenarios, biomass resource utilization on the order of 630–830 million metric dry tons per year is sufficient to serve the transportation fuel sector by 2050.
- Expansion of new low-carbon fuel production capacity in the low-carbon scenarios is approximately twice the new petroleum fuel production capacity needed in the Business As Usual scenario, ranging from 1.5 to 2.0 billion gallons of gasoline equivalent energy per year of capacity annually after 2020. Capacity expansion requirements would be reduced if biomass-based pyrolysis oil products can be processed in existing refinery systems.
- In general, retail infrastructure capital costs in the low-carbon fuel scenarios are comparable to those in the Business As Usual scenario, though capital costs for electricity and hydrogen are higher than for liquid fuels. For some fuels, such as compressed natural gas and hydrogen, it may prove challenging to provide adequate geographic coverage for the light-duty vehicle market while maintaining economically favorable station sizes or fuel throughput.

Different Fuels Scenarios All Reach Deep GHG Reductions

The scenarios developed for this report represent a range of possible low-carbon fuel demand outcomes that would all reach the 2050 GHG reduction goal. The scenarios were developed to explore contrasts among infrastructure expansion needs for different fuels. Scenario trends to 2050 were developed using an internally consistent vehicle stock and fuel consumption analytic framework in a modified version of Argonne National Laboratory's VISION model (Argonne National Laboratory 2011). Inputs to this model were derived from a number of external sources as well as from modeling results described in other Transportation Energy Futures (TEF) reports (Grenzeback et al. 2013; Plotkin et al. 2013; Porter et al. 2013; Ruth et al. 2013; Vyas et al. 2013). The following four scenarios were developed:

- **Business As Usual:** No significant transportation-sector changes that would reduce petroleum use or GHG emissions.
- **Portfolio:** Successful deployment of a variety of advanced vehicle and fuel technologies.

- **Combustion:** Market dominance by more efficient end-use technologies that are fueled by advanced biofuels and natural gas.
- **Electrification:** Market dominance by electric-drive vehicles in the light-duty vehicle (LDV) sector, including battery electric, plug-in hybrid, and fuel cell vehicles, fueled by low-carbon electricity and hydrogen.

These scenarios were developed using a bottom-up analytic approach, based on input assumptions that include projections of transportation services, changes in market share of different technologies, and technology improvement trends. They are not the result of an integrated economic or technology optimization model. Key inputs for the low-carbon scenarios—Portfolio, Combustion, and Electrification—include reductions in activity levels below the BAU scenario and improvements in the efficiency of end-use technologies. Beyond these demand changes and efficiency improvements, the scenarios are distinct from each other with respect to assumptions about the types and volumes of low-carbon fuels used for the remaining reductions to attain the 80% GHG reduction goal by 2050. Figure ES.1 is a general depiction of how reductions based on changes in demand, improved efficiency, and use of low-carbon fuels combine to a total 80% GHG reduction by 2050: demand reductions account for approximately 10%; non-LDV (NLDV) and LDV efficiency improvements for approximately 55%; and use of low-carbon fuels for approximately 35%.

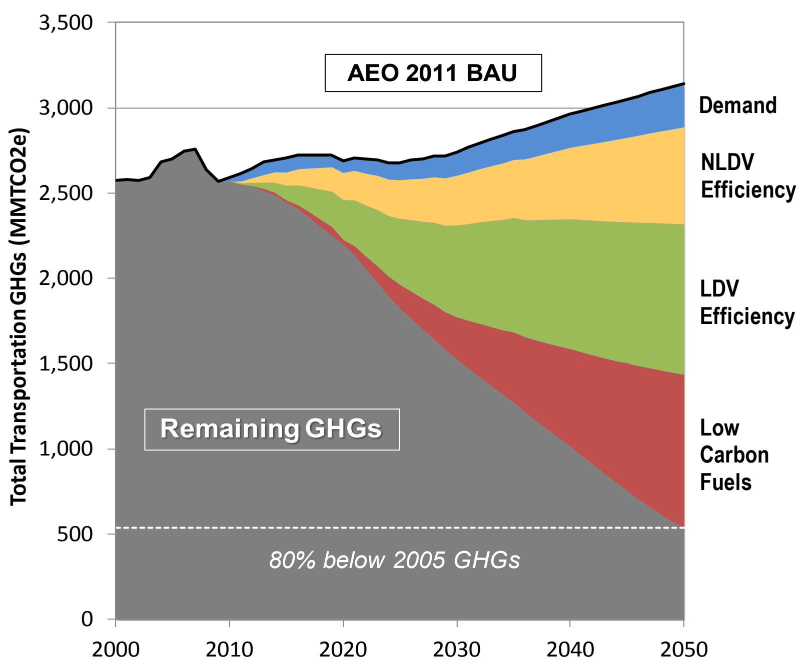


Figure ES.1. General depiction of low-carbon scenario GHG reductions due to demand reductions, efficiency improvements, and introduction of low carbon fuels

$MMTCO_2e$ = million metric tons of carbon dioxide equivalent

The resulting demand for different types of transportation fuels in 2050 is summarized in Figure ES.2 for each of the four scenarios. All three low-carbon scenarios have significantly decreased fuel demand due to less demand for motorized transportation services and greater fuel economy of vehicles. As indicated, conventional gasoline is nearly completely displaced and use of conventional diesel is reduced dramatically. Each scenario involves significant volumes of infrastructure-compatible biofuels for the diesel, jet, and gasoline fuel markets. Variations in the LDV market share account for much of the variation in demand for electricity, hydrogen, and compressed natural gas. Replacing conventional petroleum fuels with these low-carbon fuels would require major changes in the vehicle fleet, fuel production, and retail fueling infrastructures.

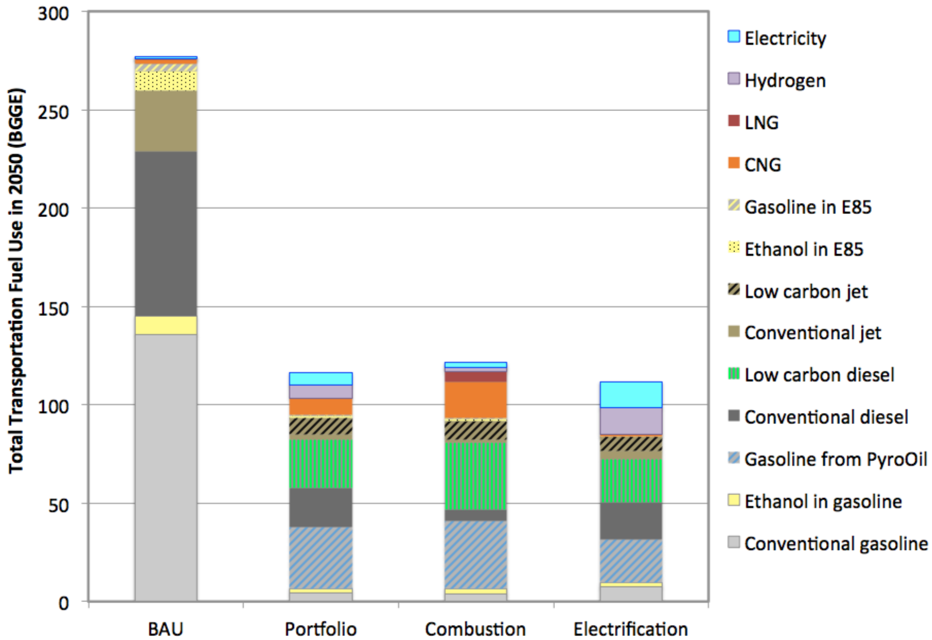


Figure ES.2. Volume of total transportation fuel use by scenario in 2050

BGGE = billion gallons of gasoline equivalent energy; CNG = compressed natural gas; E85 = ethanol-gasoline blend with approximately 85 percent ethanol by volume; LNG = liquid natural gas; PyroOil = pyrolysis oil.

The Portfolio scenario rolls out multiple fuel types in parallel, the Combustion scenario emphasizes infrastructure-compatible liquid biofuels and use of compressed natural gas in LDVs, and the Electrification scenario includes significant expansion of both hydrogen and electricity for LDVs.

Infrastructure Evaluation Criteria

The scenarios were evaluated on the basis of fuel cost estimates, resource availability, fuel production capacity expansion, and retail infrastructure expansion. The results of the evaluation of these criteria are summarized below.

Fuel Costs. Relative cost is one criterion for evaluating each alternative fuel–vehicle system and its associated infrastructure. Based upon assumed long-term cost estimates, we find that each low-carbon scenario results in total fuel costs that could be lower than expenditures in the BAU case, which is based on extrapolation of the 2011 *Annual Energy Outlook* (AEO) Low Oil price case (Energy Information Administration 2011). Due to assumed greater vehicle efficiency, the low-carbon scenarios use far less fuel overall, contributing to lower total fuel costs. The estimates in this report suggest total fuel savings on the order of $200 billion–$1,000 billion per year by 2040–2050 when compared to the AEO Low Oil price case and High Oil price case, respectively. However, these fuel cost estimates are bottom-up technology estimates, and therefore likely underestimate actual fuel prices that would be realized as market outcomes.

Energy Resource Availability. Energy resource availability to supply each alternative fuel pathway is another key metric in understanding the feasibility of low-carbon transportation fuel scenarios and associated fuel infrastructures. Given the low-carbon scenario input assumptions about demand reduction and end-use efficiency improvements, biomass resource utilization ranging from 630–830 million dry short tons per year would be sufficient to serve the transportation fuels sector. Biomass resources—based on the updated *Billion Ton Study* (U.S. Department of Energy 2011) estimate—appear adequate for biofuels to play a major role in a very low-carbon transportation sector, although we have not fully accounted for regional differences or for competition for biomass resource within the transportation sector or among the transportation sector and other sectors. Moreover, natural gas and renewable sources of electricity also appear adequate to meet demand in the low-carbon scenarios.

Fuel Production Capacity Expansion. Expansion of the low-carbon fuel production infrastructure is about twice as large as the expansion for petroleum refining capacity in the BAU scenario (an extrapolation of the 2011 AEO Reference case from 2035 to 2050). While the low-carbon scenarios involve significant new fuel production infrastructure, these scenarios use much less fuel overall. New production capacity requirements in the low-carbon scenarios can be significantly reduced to the degree that biomass-based pyrolysis oil products can be refined in existing petroleum refining systems.

Retail Infrastructure Expansion. Expansion requirements for retail infrastructure components, such as the number of refueling or recharging stations needed to serve a particular urban market, depend upon assumptions about market growth, urban area population density trends, and retail sector market dynamics to 2050. For some fuels that require new retail infrastructure, such as natural gas or hydrogen, infrastructure analysis suggests that it may prove challenging to provide sufficient geographic coverage while maintaining economically favorable station sizes. In general, retail infrastructure capital costs are a relatively small share of total fuel costs in the low-carbon and BAU scenarios. Electricity and hydrogen stations tend to add more retail infrastructure costs than stations for biofuels or compressed natural gas.

These findings are based on an analytic approach that draws upon published literature on transportation systems and alternative fuels, as well as multiple sources of data on technology cost and performance projections. The scenarios presented here are therefore largely based upon analytic results previously reported elsewhere and do not rely heavily upon new analysis of vehicle or fuel systems. The contribution made here to the existing literature is a comparison of consistent metrics across distinct scenarios involving a broad range of technology types. The geographic and market analysis of retail infrastructure expansion requirements in each low-carbon scenario is a novel contribution to the growing literature on low-carbon transportation futures.

This report identifies the following areas where additional research could improve future analyses by refining modeling assumptions and extending the analysis framework to incorporate relevant topics that were outside the study scope, including:

- Explore stakeholder decision-making processes influencing investments in fuel production and retail infrastructure, including evaluating fuel-specific costs, technical challenges, market opportunities and barriers, policy and financing mechanisms, and environmental and social effects.
- Estimate fuel infrastructure expansion costs and assess them in the context of the total cost of driving, including fuel costs, vehicle ownerships costs, and environmental and social impacts associated with fuel use and transportation services.
- Improve understanding of consumer vehicle purchase decisions and the influence of spatial proximity and geographic coverage of different types of refueling infrastructure (for electricity, liquid fuel, liquid natural gas, compressed natural gas, and hydrogen), in different locations (residences, worksites, and publicly accessible sites), and with different refueling times (e.g., Level 1 vs. Level 2 electric vehicle supply equipment) and vehicle ranges (e.g., battery electric vehicles vs. plug-in hybrid electric vehicles).
- Explore the potential role of public-private partnerships (including involvement of electric and natural gas utilities, or current fuel providers) in supporting infrastructure planning and expansion, and in overcoming market barriers.

- Analyze markets for various vehicles and fuels at a geographically detailed level to understand region-specific effects on technology roll-out and the potential for regionalized markets, including the influence of state and local policy incentives.

Scenario development to meet explicit goals for GHG or petroleum reduction can improve understanding of both near- and mid-term market dynamics, as well as long-term technology potential. The results presented here provide some insights into key scenario evaluation criteria and help to outline future challenges in modeling the market introduction and infrastructure expansion of alternative low-carbon transportation fuels. This work is policy-neutral with regard to a policy of adopting GHG or petroleum reduction goals; it explores the potential contribution of alternative fuels to meeting such goals if they were adopted.

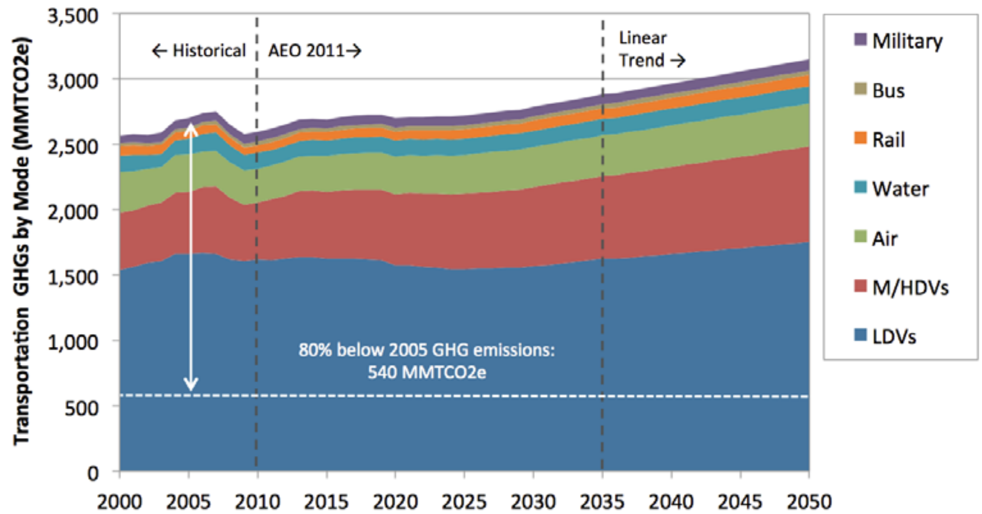
1. INTRODUCTION

Today's transportation sector is served by a very large, efficient, and reliable petroleum-based liquid fuel infrastructure. A range of fuel and vehicle technology combinations have been proposed and assessed as alternatives to the current system that would provide sustainable, non-petroleum, low-carbon mobility. Many of these alternatives would require new or modified fuel infrastructure. The results of numerous past studies have focused on a wide range of topics to improve the understanding of the relative merits of these technologies, including vehicle designs, fuel production and delivery processes, techno-economic policy modeling, and consumer behavior patterns (Sperling 1988; Tompkins et al. 1998; Greene 2001; Bandivadekar et al. 2008; Morrow et al. 2010). A few studies have examined low-carbon fuel scenarios for the entire transportation sector (Yang et al. 2008; McCollum and Yang 2009), but most have focused on the light-duty vehicle (LDV) market segment (Melaina and Webster 2011; National Research Council 2013). Many studies have concluded that the cost of reducing greenhouse gas (GHG) emissions is higher in the transportation sector than in other sectors (Ribeiro et al. 2007; Bandivadekar et al. 2008; International Energy Agency 2010; McKinsey & Company 2010; McCollum et al. 2012). Some studies have recommended a portfolio policy approach that supports multiple low-carbon fuel and vehicle options as a viable strategy (The Energy Foundation 2001; International Energy Agency 2010), and other studies have found that the differences in costs and benefits associated with these technology combinations are relatively small (Ogden et al. 2004; Yeh et al. 2008). These results suggest a need to characterize additional distinctions between technology options, moving beyond comparisons of cost and performance metrics, especially with regard to scenarios for deep reductions in GHG emissions and petroleum use over the long term.

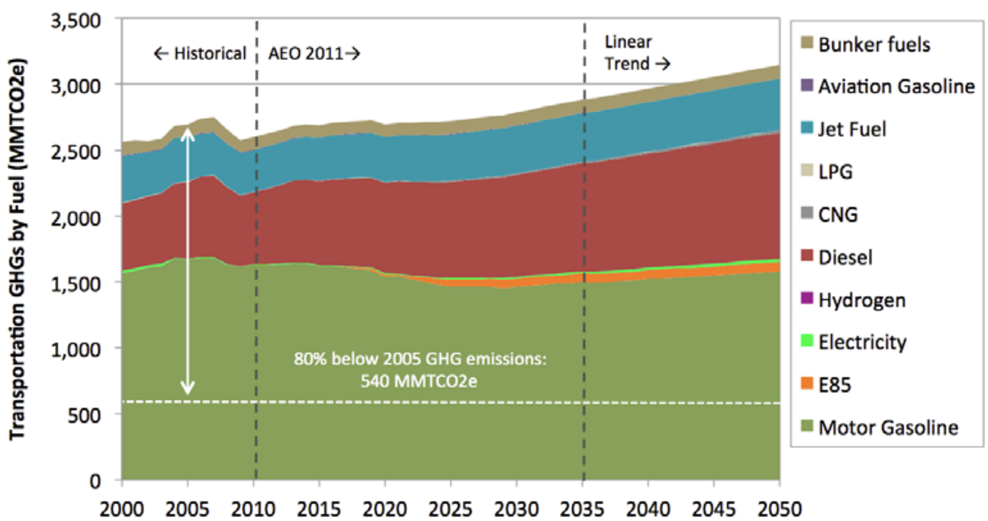
To address this need, this study employs a scenario approach to provide insight by focusing on infrastructure expansion trends required for fuel supply systems that would meet a goal of reducing 2050 transportation sector GHG emissions to 80% below 2005 levels, and deeply reducing petroleum use. This GHG emission reduction level has been identified as a target threshold for slowing climate change (Azar and Schneider 2002; U.S. Department of State 2010). This goal was used as a constraint in developing low carbon scenarios, and this report does not proposed it as a policy objective.

Alternative low-carbon fuels would be most competitive in replacing petroleum fuels if they can offer levels of cost, convenience, and reliability similar to today's system (Ogden and Anderson 2011). To reduce GHG emissions significantly across the entire transportation sector, the infrastructure that produces and delivers these fuels would need to expand to provide large volumes of fuel to a diverse set of end users dispersed across large geographic regions. Moreover, this expansion would need to take place quickly to meet the GHG emissions reduction goal by 2050. In some cases, such as for compressed natural gas (CNG), electricity, and hydrogen, this infrastructure expansion and vehicle adoption would be interdependent. Section 2 provides an overview of the existing petroleum fuel infrastructure as context for the low-carbon fuel infrastructure expansion requirements evaluated later in the study.

This paper compares a business-as-usual (BAU) scenario with three low-carbon scenarios. The low-carbon scenarios explore distinct means to reach an aggregate 80% reduction in GHG emissions below 2005 levels by 2050 across seven U.S. transportation market segments: 1) LDVs, 2) medium-duty and heavy-duty vehicles (M/HDVs), 3) air, 4) marine, 5) rail, 6) bus, and 7) military. The fuel supply analysis in this paper takes into account fuel demand from all of these sectors, while the discussion of retail fueling infrastructure considers demand primarily from LDVs. The GHG emissions associated with fuel use within each of these market segments in the BAU scenario are shown in Figure 1.1, with projections from the reference case in the *Annual Energy Outlook (AEO) 2011* for years 2010–2035 [for details, see Energy Information Administration (EIA) 2011] and linear extrapolations beyond 2035 to 2050 based upon trends between 2025 and 2035. GHG emissions are also shown by fuel type. These projections suggest an increase in GHG emissions of 17% from the 2,698 million metric tons of carbon dioxide equivalents ($MMTCO_2e$) in 2005 to the estimated 3,148 $MMTCO_2e$ in 2050. There is considerable uncertainty as to whether the reference case represents the most likely future outcome, and side cases in the AEO explore future conditions, such as higher or lower oil prices, that might result in different energy use and GHG emission profiles. As indicated in the figure, the 80% reduction goal is 540 $MMTCO_2e$, which is an 83% reduction below the 2050 BAU GHG estimate.[2]



(a) GHG projections by transportation market segment



(b) GHG projections by transportation fuel type.

Figure 1.1. Projected transportation GHG emissions by (a) market and (b) fuel compared to the 2050 GHG goal

Extrapolations beyond 2035 AEO projections are based upon linear trends between 2025 and 2035.

[2] This 2050 GHG estimate is unique to this study. It includes increased fuel carbon intensities associated with unconventional sources of crude oil, such as tar sands. The baseline does not include fuel used for transport via pipelines, such as natural gas to power pipeline compressors, and it does not include petroleum products used as lubricants, such as motor oil. While these two markets are conventionally included by the EIA within the transportation sector, they are considered outside the scope of this study due to anticipated pipeline improvements largely being electrification and lubricant carbon intensity improvements (e.g., bio-based) arising from the industrial sector.

The potential for fuels to contribute to transportation GHG emissions reductions depends upon two key non-fuel trends: 1) the demand for transportation services, and 2) the efficiency with which fuels are consumed by end-use technologies to provide those services. In the LDV market, for example, demand would be measured in vehicle miles traveled (VMT) per year, and efficiency would be measured in miles per gallon of gasoline equivalent energy (mpgge). For air transport, demand is measured in seat miles traveled, and efficiency is measured in seat miles per gallon. The potential to shift these demand and efficiency trends towards a low-carbon transportation future has been examined in parallel studies, the results of which were inputs for this analysis (Stephens 2013; Vyas et al. 2013). For example, each low-carbon scenario assumes a 10% reduction in LDV VMT and a 15% reduction in M/HDV VMT, as well as aggressive improvements in end-use efficiency for rail, M/HDV, air, and LDV modes. These demand and end-use efficiency scenario input assumptions are reviewed in Section 3.1. The resulting time series estimates of the quantities of fuel required in each mode are reviewed in Section 3.2.

Building upon these fuel demand estimates, three distinct low-carbon fuel supply scenarios have been developed that meet the 80% GHG emission reduction goal by 2050:

Portfolio Scenario. A wide variety of low-carbon end-use and fuel technologies are assumed to achieve commercial success. In this scenario, the government is assumed to support a “portfolio” of advanced technology options, and all or most of these options are then successfully brought to market expediently and in large volumes by private industry. The policy environment is assumed to include sufficient incentives to reach deep reductions in GHG emissions and petroleum use, with explicit support of less-competitive fuels and technologies to push a broad portfolio of options toward commercialization.

Combustion Scenario. In this scenario, hybrid-electric internal combustion engine vehicles become the dominant technology for LDVs, and advanced low-carbon biofuels and natural gas become the primary fuels across the transportation sector. Compared to the other two scenarios, the Combustion scenario could conceivably occur with less emphasis by government on “pushing” advanced technologies into the market; the primary focus of government intervention in this scenario is assumed to be support for advanced biofuels production and deployment of CNG vehicles and retail infrastructure. The policy environment is assumed to include sufficient incentives to reach deep reductions in GHG emissions and petroleum use, but without placing priority on technology diversity or electrification.

Electrification Scenario. This scenario relies upon widespread use of low-carbon electricity and hydrogen, primarily for LDVs, but also within other fuel pathways and end-use technologies. Compared to the other two scenarios, the Electrification scenario assumes that focused government support is forthcoming, if necessary, for deployment of advanced battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs), as well as support for the infrastructure expansion needed to supply these vehicles with low-carbon hydrogen and electricity. The policy environment is assumed to include sufficient incentives to reach deep reductions in GHG emissions and petroleum use, with a strong emphasis on electrification as a technology strategy.

Additional characteristics of these three low-carbon scenarios are summarized in Table 1.1. Comparisons in the table for market pull and expanding fuel infrastructure are relative to the low-carbon scenarios indicated, not to the BAU scenario. For the Portfolio scenario, it is assumed that public and private research, development, and deployment efforts supply low-cost technology options, so market pull is shown as playing a relatively minor role. The influence of market pull is higher in the Combustion scenario, with efficient but relatively inexpensive alternative fuel vehicles, while focused policy support for electric-drive vehicles has high influence in the Electrification scenario (Sanden and Azar 2005).

Table 1.1. General Low-Carbon Scenario Characteristics

Scenario Characteristic	Scenario		
	Portfolio	Combustion	Electrification
Assumptions about technology innovation success	Widespread success across multiple vehicle and fuel types	Major successes with advanced biofuels; success with hybrid electric vehicles	Major successes with electric drive vehicles and low-carbon electricity and hydrogen; moderate success with biofuels
Types of government support likely to be required	Concerted policies to retain a broad portfolio	Focused on natural gas and advanced biofuels	Focused on electric drive vehicles and low-carbon electricity and hydrogen
Assumed relative influence of market pull in commercializing new low-carbon technologies	Low	High	Moderate
Relative effort in expanding new fuel supply infrastructure to achieve fuel carbon reductions	Moderate	Low	High

The mix of low-carbon fuels used in each of these scenarios to meet the 2050 goal is reviewed in Section 3.2. Section 4 then evaluates fuel infrastructure expansion trends based on four criteria: 1) estimated fuel costs, 2) energy resource availability, 3) rates of fuel production capacity expansion, and 4) expansion of retail infrastructure components. Section 5 summarizes the main conclusions.

2. EXPANDING FUEL INFRASTRUCTURE

Each of the low-carbon fuel technologies could play a role in reaching an 80% reduction in GHGs in the transportation sector. Predicting which of these fuels is likely to offer large reductions is challenging. Market simulation models have attempted to predict future market shares for vehicles and fuels under carbon constraints, but this analytic capability is limited by a number of factors, including difficulty in quantifying non-cost barriers, uncertainties surrounding technology change and policy effectiveness, and the difficulty of formulating, analytically, interactions between industry and government stakeholder behavior and consumer decisions or preferences (Greene et al. 2008; Yeh et al. 2008; Plotkin et al. 2013; Stephens 2013). Other analytic challenges are the high degree of uncertainty surrounding the future cost of low-carbon, petroleum, and unconventional fuels; cross-sector market effects of increasing demand for low-carbon energy resources such as biomass; and the various policy influences and market dynamics associated with bringing advanced and novel fuels and vehicles to market in large volumes. Although sophisticated models have been developed to address these and other challenging issues (Winebrake and Creswick 2003; Stephan and Sullivan 2004; Newes et al. 2012), some analysts have called for simple scenario approaches rather than using cost optimization or market simulations forecasting (Craig et al. 2002).

This study adopts a scenario framework based upon simplified projections of technology improvements and stakeholder behavior. Although this approach is not predictive, it does allow for a coherent and self-consistent examination of fuel infrastructure expansion trends across a range of possible market shares for major vehicle and fuel types. It also allows for a relatively detailed comparison to a BAU expansion of the petroleum fuel infrastructure. The two sections below review key attributes of the vehicle-fuel pathways examined in this study and international experiences with programs supporting CNG vehicles and supporting fuel infrastructure, which is pertinent as an example of recent fuel infrastructure development.

2.1. Vehicle-Fuel Pathways

Figure 2.1 outlines major infrastructure supply chain components for various liquid fuel, gaseous fuel, and electricity pathways. The key at the left of the Figure 2.1 color-codes each of the infrastructure components as existing (blue, solid outline), new production technologies (red, dashed outline), or new fuel delivery technologies (green, dotted outline). Major energy resources are numbered by type below the key, and these numbers are used to indicate which resources are or might be utilized in existing or new production technologies. For example, refineries predominantly rely upon petroleum (1), natural gas (2), and (increasingly) unconventional fossil fuels (4). The top portion of the Figure 2.1 shows supply chains for both liquid petroleum and liquid biomass fuels, with two "upstream" biofuel pathways blending into the petroleum product supply chain: pyrolysis oil and algal oil are introduced at the refinery and fatty acid methyl esters, ethanol, and Fischer-Tropsch (FT) biofuels are blended with refinery output products (Bunting et al. 2010). Another option for blending these biofuels, as well as biobutanol and green diesel, is to blend at a location closer to the end use, such as at the truck delivery terminal. These biofuels can also be delivered directly to market via truck to refueling stations as gasoline (which is mostly E10, an ethanol-gasoline blend with approximately 10% ethanol by volume), E85 (an ethanol-gasoline blend with approximately 85% ethanol by volume), or biodiesel fuels. The upstream blending pathways are means of bringing infrastructure-compatible biofuels to market while making relatively minor modifications to the existing gasoline and diesel production and delivery infrastructure.

Two gaseous fuel infrastructure supply chains are shown in the middle of the Figure 2.1: natural gas and hydrogen. The natural gas supply chain is shown in a simplified manner, with transmission pipelines or liquefied natural gas (LNG) tankers providing large-volume delivery. CNG stations are shown connected to distribution lines while LNG stations (not shown) would receive fuel via LNG delivery trucks. One crossover from the biofuels infrastructure is biogas entering the natural gas infrastructure, injected into either the transmission or distribution pipeline systems. Similarly, hydrogen can be introduced into the natural gas infrastructure (at low volumetric percentages), with large central production facilities being more likely to inject hydrogen at the transmission line than elsewhere and regional production facilities being more likely to inject hydrogen into distribution lines (Florisson 2010; Melaina et al. 2013). Hydrogen can be produced from a wide range of sources and at various scales, with major delivery options including pipeline, liquid truck, or high-pressure gaseous trucks. Onsite hydrogen production at the fueling station, from natural gas, electricity, or reforming of biofuels such as ethanol or bio-oil, is an alternative to hydrogen delivery. The bottom of Figure 2.1 shows a simplified electricity supply chain, with generation types, transmission lines, distribution lines, and transformers as key infrastructure components upstream of vehicle charging stations, referred to here as electric vehicle supply equipment (EVSE).

Figure 2.1 does not capture all possible fuel pathways or combinations, but it does outline major options for expanding alternative fuel infrastructure. For example, it does not include the use of biogas to produce electricity, production of byproduct electricity at biofuel or hydrogen production plants, or the use of hydrogen storage to buffer variable renewable electricity supply. These and other novel supply chain options could prove economically competitive in a low-carbon future. They are not examined in this study for the sake of simplicity and because they are considered second order to the very basic infrastructure expansion metrics under examination. However, a more detailed examination of technically or economically synergistic relationships between infrastructure systems could reveal additional opportunities to expand fuel infrastructure more efficiently and at lower cost.

Figures 2.2 – 2.4 indicate the fuel pathways considered in this study. Figure 2.2 indicates pathways that provide biofuels through the existing gasoline or diesel infrastructure systems. Advanced biomass-based blendstocks or fuels that can be inserted into existing systems with relatively minor modifications are under development, and are collectively referred to as “infrastructure-compatible” pathways in this report. In addition to these infrastructure-compatible pathways, E85 is a unique variation on the fuel blending option, and butanol is a nominal or partial infrastructure-compatible biofuel. In the three low-carbon scenarios, the majority of advanced low-carbon ethanol is blended with gasoline rather than being sold as E85. Figure 2.3 indicates various production options for diesel fuel. In this analysis, a generic diesel liquid fuel is assumed to represent the fuels required for the M/HDV, air, and marine market segments, when in fact these markets are served by distinct grades of diesel fuel. Figure 2.4 indicates a variety of fuel and vehicle options for the LDV market segment. Gasoline, diesel, and E85 flex fuel vehicles can be hybridized, while gasoline plug-in hybrid electric vehicles (PHEVs) can also be charged to enable some fraction of miles driven to be electric miles. Electricity is used in BEVs, and hydrogen is used in FCEVs, while plug-in hybrid electric fuel cell vehicles can use electricity and hydrogen. Many other potential vehicle-fuel combinations could be added to this list, such as diesel PHEVs or internal combustion engine hybrid-electric vehicles (HEVs) burning hydrogen, hythane (a blend of hydrogen and natural gas), dimethyl ether, or ammonia (Ogden et al. 2011). But again, these and other options have been excluded for the sake of simplicity. Their inclusion would not significantly enhance the main goal of understanding basic fuel infrastructure expansion trends needed to support a low-carbon transportation system.

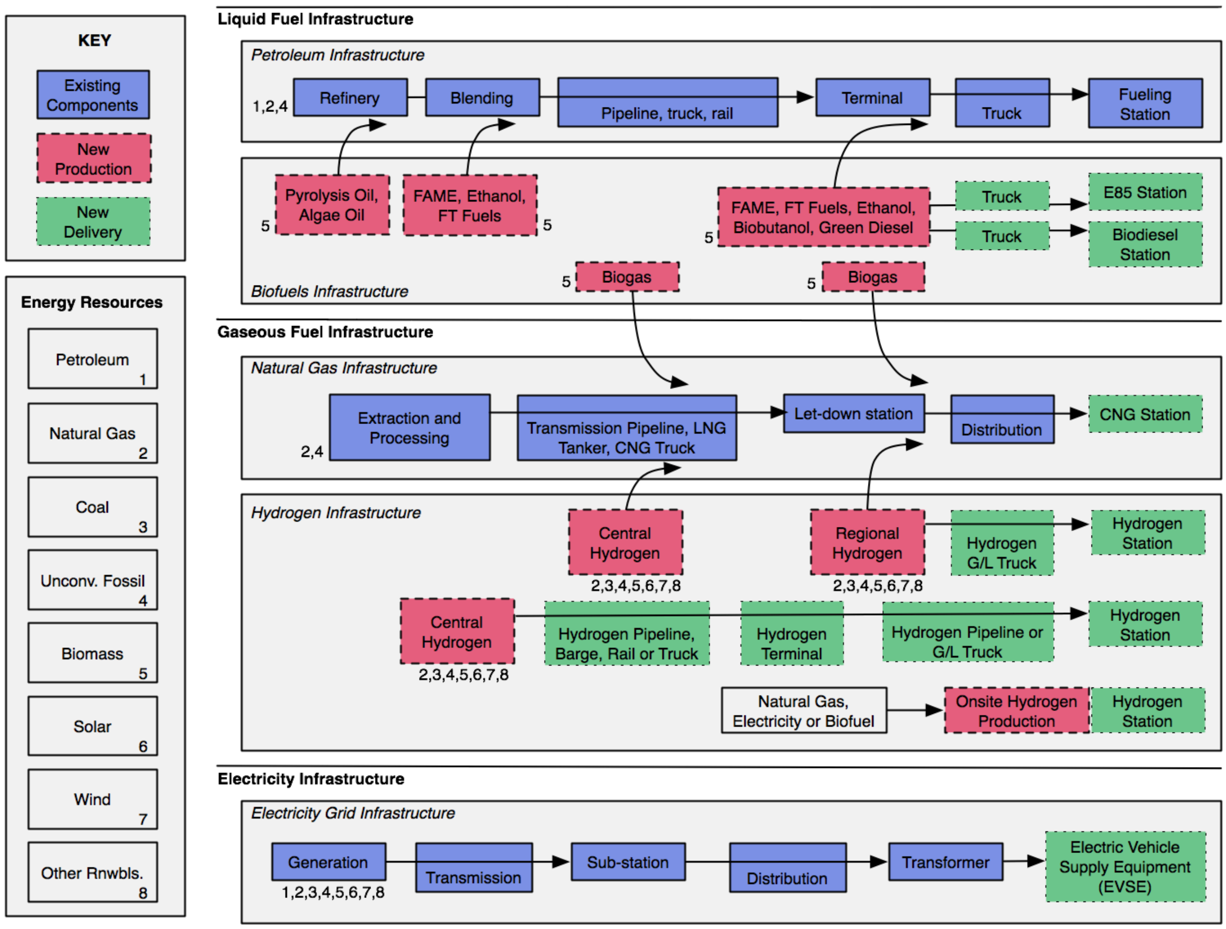


Figure 2.1. Existing and new infrastructure components for producing and delivering liquid fuels, gaseous fuels, and electricity

(Source: Derived from Bunting et al. 2010)

CNG = compressed natural gas; E85 = ethanol/gasoline blend with 85% ethanol by volume; FAME = fatty acid methyl esters; FT = Fischer-Tropsch; G/L = gaseous/liquid; LNG = liquid natural gas

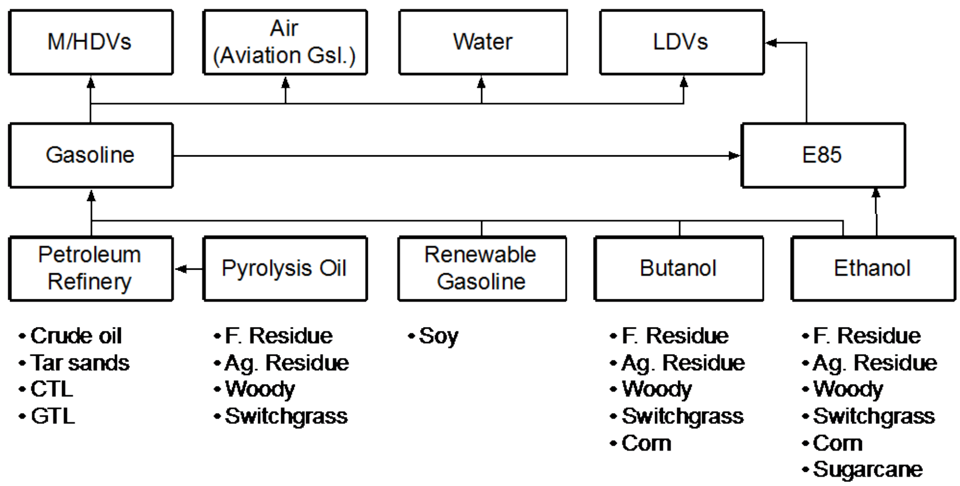


Figure 2.2. Gasoline and ethanol blend pathways examined in this study

Ag. Residue = agricultural residue; CTL = coal to liquids; F. Residue = forest residue; GTL = gas to liquids

Fuels are produced from multiple feedstock types and used in multiple market segments. Pyrolysis oil intermediates used in refineries are produced from biomass resources, and butanol is indicated as a nominal infrastructure-compatible fuel to be blended with gasoline. Ethanol can be blended with gasoline either at low levels as E10 or at high levels as E85.

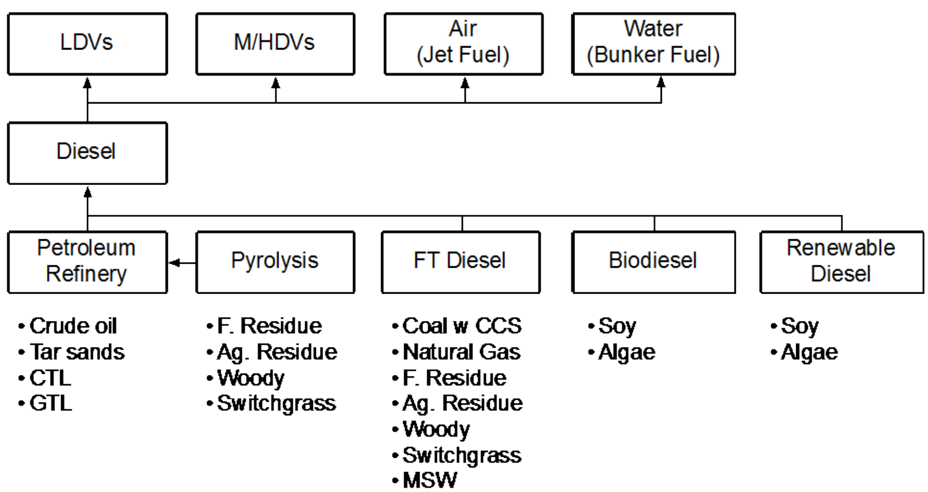


Figure 2.3. Diesel blend pathways examined in this study

Ag. Residue = agricultural residue; CCS = carbon capture and storage; CTL = coal to liquids; F. Residue = forest residue; GTL = gas to liquids; MSW = municipal solid waste

Fuels are produced from multiple feedstock types and used in multiple market segments. Pyrolysis oil intermediates used in refineries are produced from biomass resources, and FT diesel, biodiesel, and renewable diesel products are blended.

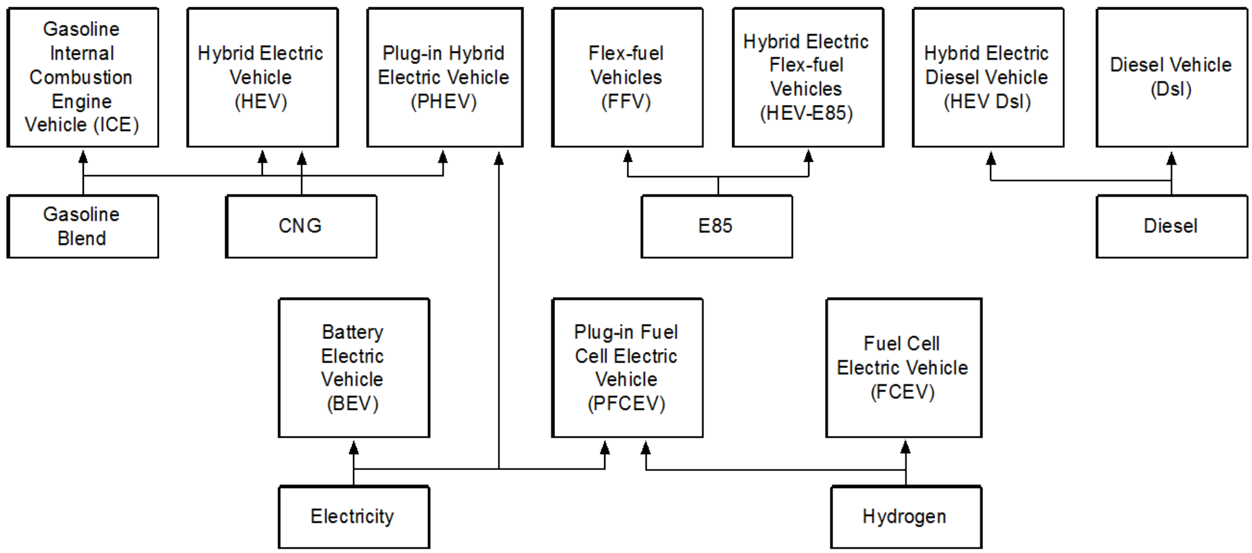


Figure 2.4. Fuel pathways for LDVs examined in this study

2.1.1. Petroleum Fuel Infrastructure

The low-carbon scenarios are evaluated with reference to a BAU scenario in which petroleum fuels dominate transportation fuel markets out to 2050 (see Figure 1.1b). The infrastructure components required to supply petroleum fuels in the BAU scenario provide context for evaluating the infrastructure expansion requirements in the low-carbon fuel scenarios. The existing petroleum fuel infrastructure, as well as BAU projections of growth trends for different components along the petroleum supply chain, is an important reference for understanding future low-carbon fuel infrastructure expansion trends. The petroleum industry has evolved over many decades of growth, adaptation, competition, learning, and technological development. Early petroleum infrastructure developments were driven by entrepreneurial stakeholders and the allure of quick profits from the sale of kerosene into lighting markets in the late 1800s. Since those early developments, the competitive instincts and efficient managerial approach first embodied by Rockefeller's Standard Oil Company continued to evolve after the industry shifted from kerosene to gasoline and diesel as the main products in the early 1900s. This evolution has resulted in an efficient and highly complex infrastructure system grounded in sophisticated supply-chain management methods (Williamson et al. 1963; Yergin 1992). Continued technological advances, global competition, and improved analytic methods have combined to increase the efficiency of the petroleum product supply chain since the 1990s (Neiro and Pinto 2004; Grossmann 2005). In comparison to this history, an emerging a low-carbon fuel infrastructure may not attain a comparable level of scale, scope, cumulative learning, or technological maturity by 2030 or even 2050. The low-carbon scenarios do not explicitly account for the market barriers, logistics, learning, or legacy effects associated with the transitional infrastructure expansion dynamics that would occur between about 2015 and 2030. Comparisons with the early transitional phases of gasoline infrastructure developments have been made elsewhere (Melaina 2007).

Figure 2.5 shows sources, processing, and use of energy in the U.S. petroleum sector from the *Annual Energy Review 2011* report (EIA 2012a). It indicates energy inputs on the left, petroleum products in the middle, and consumption markets on the right. Total energy inputs are conserved in the Figure 2.5, meaning that conversion losses are not shown as leaving the energy flow from left to right. The figure shows that crude oil production and imports comprise some 14.72 quadrillion Btu (quads).

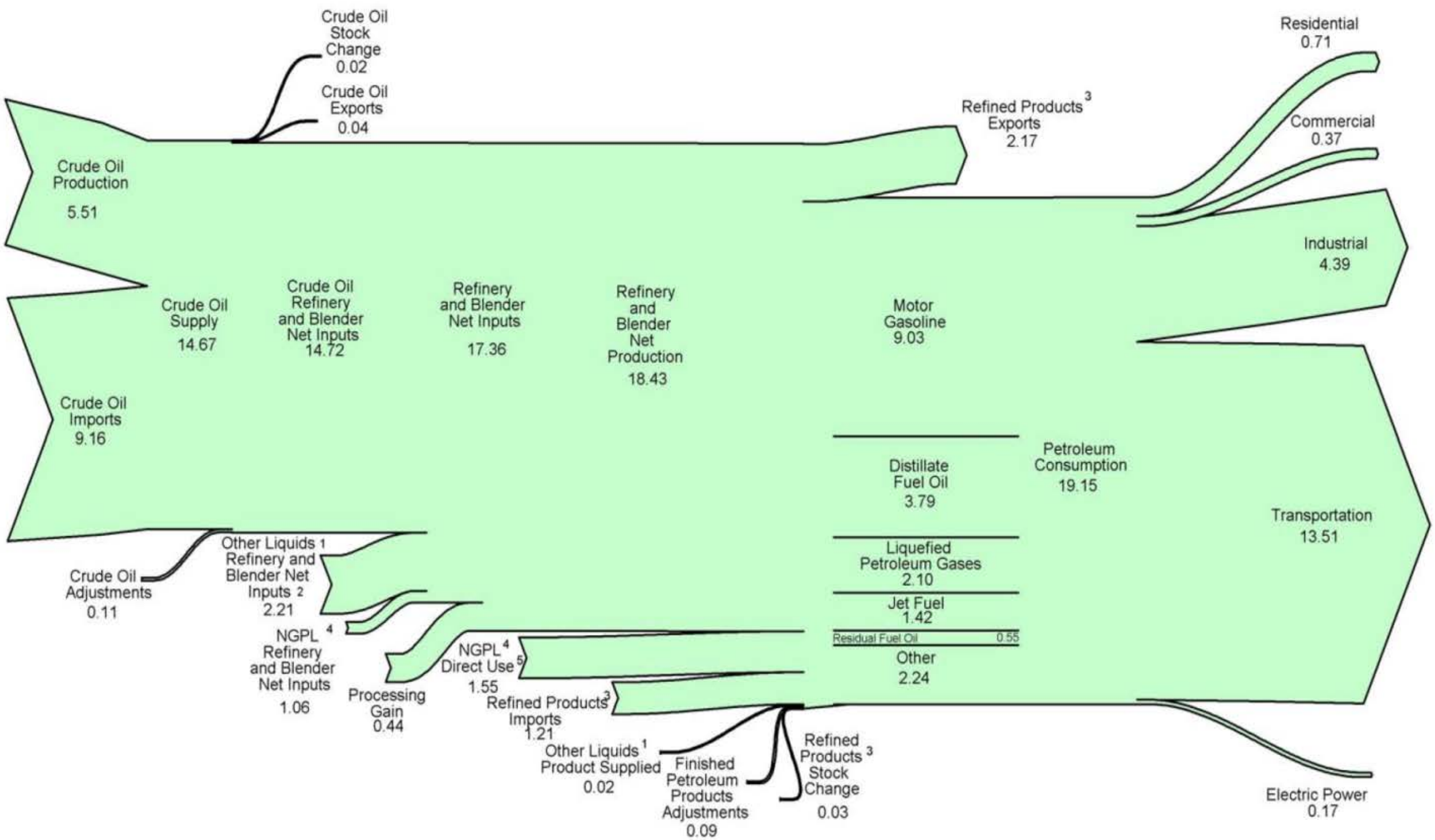


Figure 2.5. Sources, processing, and use of energy in the U.S. petroleum sector in quads

(Source: EIA 2012a, Fig. 5.0)

Notes: 1) Unfinished oils, hydrogen/oxygenates/renewables/other hydrocarbons, and motor gasoline and aviation gasoline blending components; 2) Renewable fuels and oxygenate plant net production (0.92), net imports (1.28), and adjustments (0.08) minus stock change (0.06) and product supplied (0.02); 3) Finished petroleum products, liquefied petroleum gases, and pentanes plus; 4) Natural gas plant liquids; 5) Production minus refinery input.

These are supplemented by additional refinery and blender inputs, such as renewable fuels, oxygenates, natural gas plant liquids, and processing gain, for a total of 18.43 quads of refinery and blender net production. Accounting for 2.17 quads in exported refined products, additional natural gas plant liquids, and refined product imports, total petroleum consumption is 19.15 quads. This is 19.5% of the total U.S. energy consumption of 98 quads in 2010 (see EIA 2012a*,* Figure 1.0). However, only 13.51 quads are consumed in the transportation sector (70.5% of total petroleum consumption), as indicated by the portion of the flow that is labeled "Transportation" on the right of Figure 2.5. The industrial sector consumes 4.39 quads, residential 0.71 quads, commercial 0.37 quads, and electric power 0.17 quads. Of the refined petroleum products, the majority of the motor gasoline, distillate fuel oil, and jet fuel are consumed in the transportation sector and total 12.55 quads of refined products. The "other" category of refined products is a mixture of transportation fuels and non-transportation fuel products, including asphalt and road oil, aviation gasoline, kerosene, lubricants, naphtha-type jet fuel, pentanes plus, petrochemical feedstocks, special naphthas, still gas (refinery gas), waxes, miscellaneous products, crude oil burned as fuel, and petroleum coke (see EIA 2012a, Figure 5.11). Of the 2.1 quads of liquefied petroleum gases, 99% is consumed in the residential, commercial and industrial sectors; and of the 3.79 quads of distillate fuel oil (which includes diesel fuel and fuel oils), 28% is consumed in non-transportation sectors. Of the 0.55 quads of residual fuel oil, 28.5% is consumed in the commercial, industrial, and electric power sectors (see EIA 2012a, Table 5.13a through Table 5.13d).

Major petroleum fuel infrastructure components can be summarized in three general categories: extraction (including oil wells, crude pipelines, marine terminals, and ocean tankers); production (refineries); and distribution (production pipelines, bulk storage and terminals, tank trucks, and fueling outlets). Figure 2.6 is a simplified schematic of the petroleum fuel supply chain: crude oil is delivered by tankers and crude pipelines, converted to petroleum products at refineries, delivered by product pipeline to bulk storage facilities and terminals, and then delivered by tank truck to refueling outlets (Neiro and Pinto 2004). Not indicated in this simplified figure are the crude delivery modes of marine, truck, and rail, which accounted for 27%, 3%, and 2%, respectively, of domestic crude transport in 1999 (Allegro Energy Group 2001). Crude oil production is a highly global market, and U.S. imports have tended to come from Canada, Mexico, Saudi Arabia, Venezuela, and Nigeria in recent years (EIA 2012a, Table 5.4). By the end of 2010, the United States had 148 operable refineries and 137 operating refineries, with a total operating capacity of 16.9 million barrels per day and a total idle capacity of 0.8 million barrels per day. The highest density of refineries is along the Gulf Coast, with refineries located within Texas and Louisiana accounting for 46% of all operating capacity at the end of 2010 (EIA 2012c). However, as shown in Figure 2.7, refineries are distributed across the country, connected through approximately 200,000 miles of pipelines to production fields (crude oil pipelines) and to major urban markets (product pipelines) (EIA 2012b). One source estimates that there are approximately 95,000 miles of U.S. product pipelines (American Petroleum Institute and the Association of Pipe Lines 2012), and the Internal Revenue Service reported 1,347 active fuel terminals in July of 2011 (Internal Revenue Service 2012). Estimates of the number of refueling stations vary significantly, from 100,000 to 157,000 stations, depending upon how the stations are defined and counted (see Section 2.1.2).

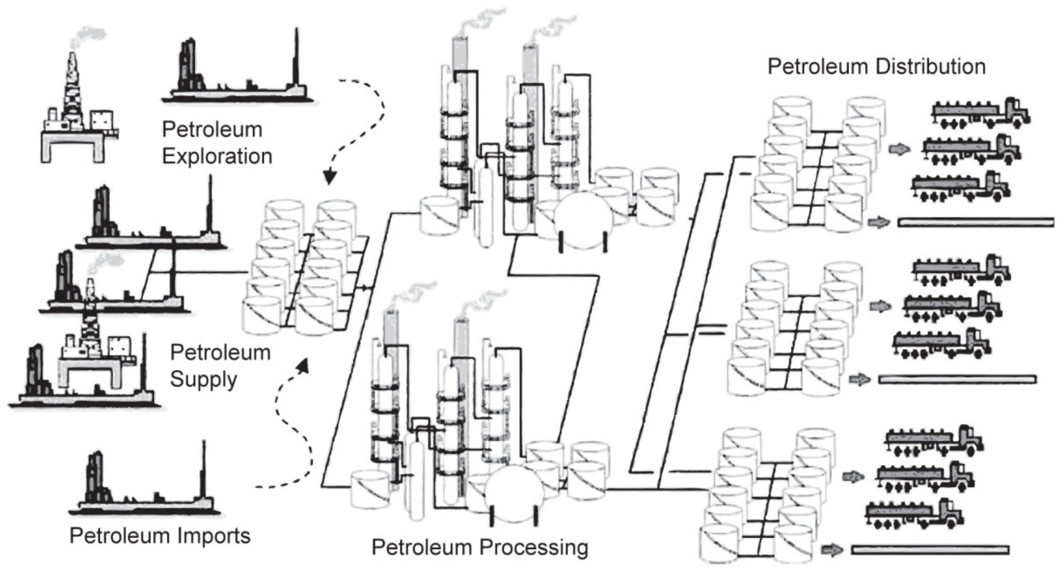


Figure 2.6. Features of a general petroleum supply chain

(Source: Adapted from Neiro and Pinto 2004)

The geographic distribution of major petroleum infrastructure components is indicated in Figure 2.7. Both crude oil and petroleum product pipelines are indicated, with crude pipelines connecting production sources or coastal import terminals to refineries, and product pipelines connecting refineries to major end-use markets. Pipelines are traditionally owned by large integrated companies, while truck delivery terminals and bulk storage facilities may be owned by smaller independent jobbers or marketers delivering refined products to market.

Product pipelines move finished products from refineries, storage facilities, and ports to terminals for truck distribution to retail sites. There are approximately 95,000 miles nationwide of refined product pipelines, and they are found in almost every state in the United States with the exception of some New England states. These refined product pipelines vary in size, from relatively small diameter (8–12 inch) lines up to 42-inch diameter lines. All interstate, common-carrier pipelines are regulated by the Federal Energy Regulatory Commission in terms of operation and tariff. Products move in a pipeline in batches ranging in size from 2,000 to 3,200,000 barrels. The speed of movement is 3–5 miles per hour. Product pipelines only ship products one way. Almost all of the pipelines are underground and are monitored constantly by operators for pressure drop and flow rates.

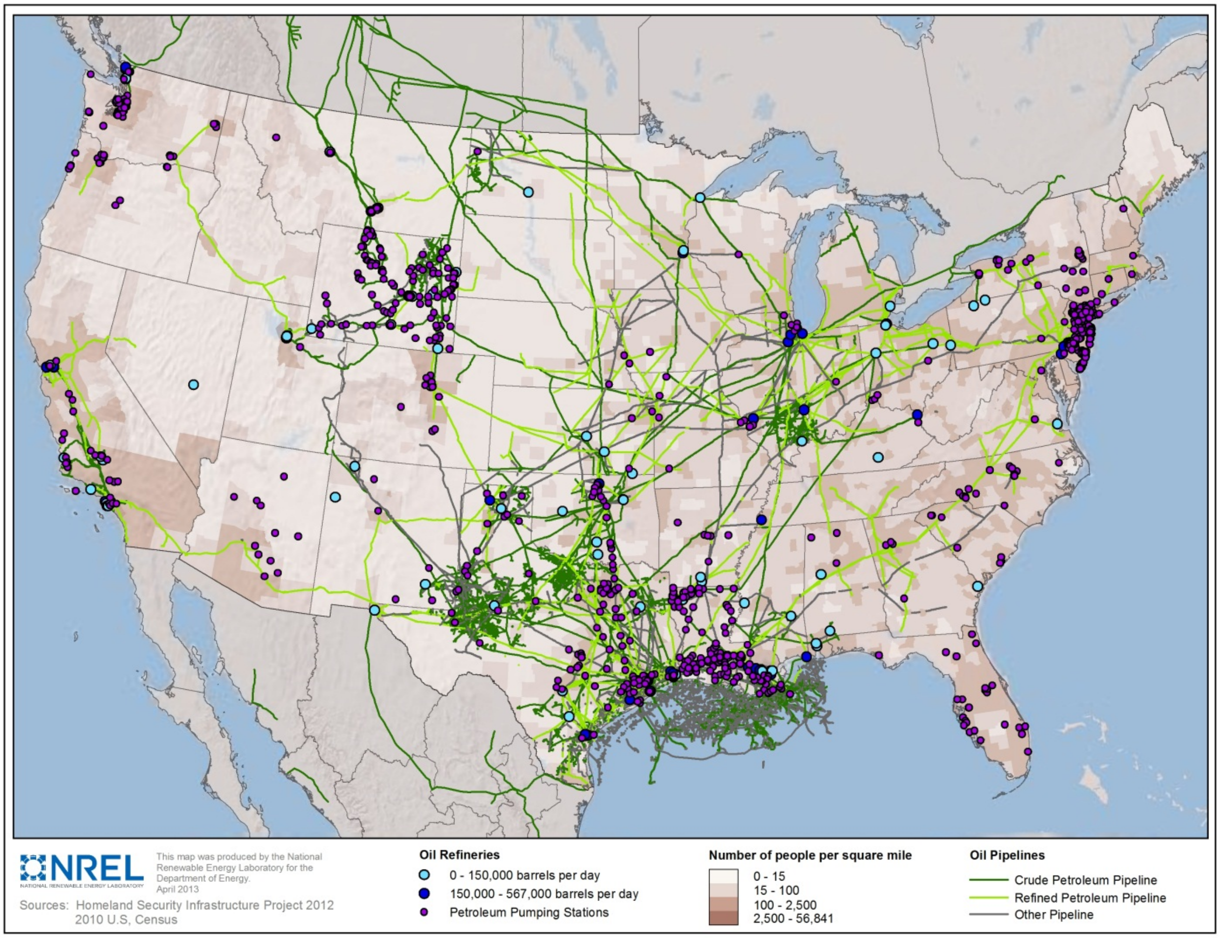


Figure 2.7. Geographic distribution of major U.S. petroleum fuel infrastructure components

(Source: National Renewable Energy Laboratory)

As indicated in Figure 2.1, there are multiple options for introducing low-carbon fuels into the existing petroleum infrastructure system, as well as the existing natural gas and electricity systems. For many liquid fuel infrastructure components, such as pipelines, pumping stations, storage tanks, terminals, and delivery trucks, the introduction of infrastructure-compatible low-carbon fuels (e.g., fuels refined from biomass pyrolysis oils) may require little or no modification to existing equipment; ethanol uses many infrastructure components that are distinct from existing petroleum systems. In contrast to these liquid fuel options, increased use of natural gas and electric vehicles would tend to require more significant infrastructure expansions "downstream," or closer to the vehicles, including compressed gas filling stations and electric charging stations. Some of these downstream or retail infrastructure components may compete with, or be combined with, existing gasoline and diesel retail outlets, which are discussed in the following section. Increased use of hydrogen vehicles would require new infrastructure across the supply chain, from production to filling stations, though existing hydrogen production capacity at refineries is significant and would be used to some degree during the early market ramp-up period.

2.1.2. Retail Station Networks

Gasoline retail station outlets are another asset of the petroleum industry that can be leveraged to deliver alternative fuels to vehicles, although the trend of large oil producers withdrawing from the retail sector complicates this leverage opportunity. Many stations are owned by smaller petroleum product marketers and an increasing number of high-volume stations are owned by large retail or "big box" stores (EIA

2001). Historical data on convenience stores that sell motor fuel, which is about 80% of all convenience stores in recent years, are provided on an annual basis through a convenience store industry survey [National Association of Convenience Stores (NACS) 2010]. As indicated in Figure 2.8, the number of convenience stores selling motor fuels has grown to be a larger fraction of the total number of motor fuel outlets. This reflects an important and ongoing change in retail fuel business models. The estimate of total outlets is based upon the annual survey conducted by *National Petroleum News* (NPN) (NPN 2011), though the NPN counts are likely an upper limit on the total number of publically available refueling locations, as they include some private or restricted locations (Melaina 2007). By comparison, the U.S. Census tracks retail stations that derive more than 50% of their income from fuel sales, resulting in a lower number of outlets than what either industry survey reports after 2007. Both datasets show that convenience stores are the dominant fraction of the public refueling station market. The NPN outlets include locations where fuel is supplied to non-light duty vehicles (NLDVs), including both public and private (fleet) outlets. Data characterizing these NLDV dispensing facilities on a national scale are sparse and incomplete. The discussion of retail outlets in this study therefore focuses on outlets serving the LDV market. The NACS and U.S. Census data are a close approximation of the total retail outlets serving LDVs, although outlets such as urban or interstate truck stops also serve M/HDVs.

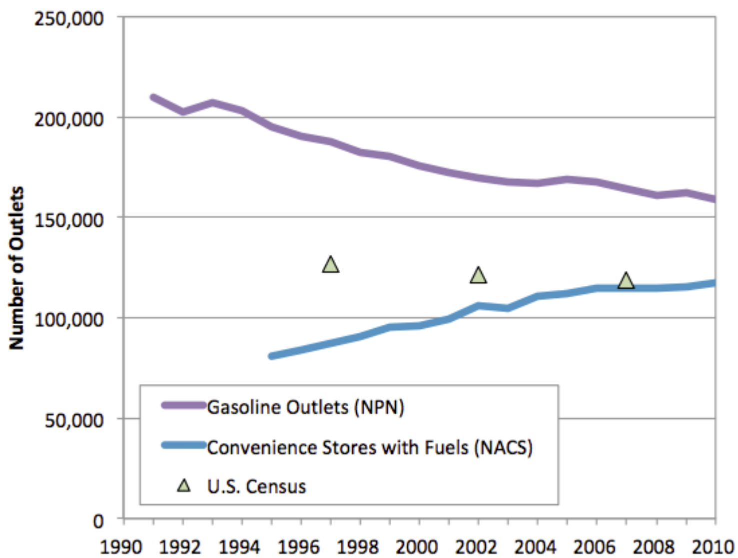


Figure 2.8. Gasoline retail outlets by source

NACS = National Association of Convenience Stores; NPN = National Petroleum News

Historical trends provided through the NACS annual survey suggest that since 1975 an average of 5,000 new convenience stores have been opened per year, and approximately 4,300 have been closed per year (3,124 convenience stores were reported in 1974, the first year of the NACS survey). Entry barriers and market conditions vary year-to-year and depend upon a variety of factors, resulting in fluctuations in the number of new entrants and closures each year. Although precise data are not available, the annual rate of openings of new convenience stores that sell motor fuel is declining. Assuming that the majority of these newly opened stores are also newly constructed at a cost of $2.5 to $3 million per station (NACS 2010), we estimate that annual investments likely range between $7.5 to $10.8 billion per year to maintain the current stock of convenience stores selling motor fuels.

These costs include buildings and land, and only about one-third of the total costs are direct costs for fueling equipment and technology (NACS 2010). The degree to which fueling equipment costs can or should be decoupled from total outlet costs is highly relevant to a cost assessment of future low-carbon fuel markets, and brings into question the degree to which today's retail outlet business models might be relied upon to sell alternative low-carbon fuels. NACS data also suggest that an average station remodel costs $300,000 per station and occurs once every 10.4 years. This would translate to approximately12,000 remodels per year and $3.5 billion total for annual remodeling costs. It is not clear how many new market entrants are new construction and how many are remodels; the $7.5–$10.8 billion per year estimate would be 10 times too high if all of the new entrants were remodels. However, given the downward trend in non-convenience-store outlets from the NPN survey (see Figure 2.8), with 74% of all outlets being convenience stores in 2010, this is probably a reasonable estimate of total annual investment into the gasoline retail outlet market.

This estimate is used in the evaluation of low-carbon scenarios as a reference for investments made in today's retail fuel sector, but it does not necessarily reflect the degree to which retail outlets rely upon revenue streams from fuel vs. non-fuel products. For the cost estimates and scenario evaluations, we assume that this bundling of services is an inherent attribute of today's gasoline and diesel retail sector. However, it is unclear if similar bundling is also required for alternative fuels such as electricity, CNG, or hydrogen, or even if current bundling practices will persist for liquid fuels into the future given the growing market dominance of outlets co-located with big box stores.

2.1.3. Availability of Retail Locations for Alternative Fueling

The availability of retail fuel locations is a significant market barrier for some low-carbon fuels and vehicles. If a new fuel is not available and convenient, consumers are unlikely to purchase dedicated vehicles that are only capable of using this new fuel. This is a major barrier for the market development of dedicated vehicles such as hydrogen FCEVs, BEVs, or CNG vehicles, and it is a significant issue for increasing alternative fuel use in flex-fuel or bi-fuel vehicles such as E85-capable vehicles, CNG bi-fuel vehicles, and PHEVs. Plug-in electric vehicles (PEVs) can also be charged at home, and it is uncertain to what extent charging at work or public commercial charging stations might support the market growth of these vehicles. Moreover, it is uncertain to what degree additional workplace or commercial EVSE might increase electric miles driven by a given fleet of PEVs. Unlike E85 or CNG stations serving flex-fuel or bi-fuel vehicles, EVSE infrastructure requirements are further complicated by rates at which vehicles can be charged, time-of-day charging benefits and drawbacks, and vehicle battery sizes, which can range from 10 to 40 miles per full charge for PHEVs and 100 or more miles for BEVs.

Early studies of the fuel availability issue relied upon surveys and interviews (Greene 1998; Tompkins et al. 1998; Brownstone et al. 2000) and some of these were referenced to available data on emerging CNG or diesel fueling station networks (Sperling and Kurani 1987; Kurani 1992). As a rule of thumb, these and other subsequent studies suggest that coverage equivalent to 10%–20% of existing gasoline stations would be sufficient to support early vehicle markets (Melaina 2003; Nicholas et al. 2004), although one survey-based study suggested that 30% may be needed for urban markets and 50% for rural (Synovate Motoresearch 2003). More recent and detailed analyses suggest that sufficient coverage could be provided if alternative fuel were available at the equivalent of less than 10% of existing stations (Nicholas and Ogden 2006; Stephens-Romero et al. 2010). Sufficient coverage requirements vary with population density and traffic patterns, and therefore vary from city to city. This is apparent from the large variations in the existing gasoline retail-network density (stations per square mile) among U.S. cities (Melaina and Bremson 2008). Another recent study examines the degree to which early market coverage requirements could be reduced through a station clustering strategy (Ogden and Nicholas 2011). While these results apply to some degree to refueling availability requirements in general, most studies focused on hydrogen fueling, given that station availability is critical to the market success of FCEVs. Bi-fuel hydrogen vehicles have been developed by BMW, Mazda, and others, but most automakers are focusing on dedicated hydrogen fuel cell vehicles (Green Car Congress 2006; Mazda 2012).

Some studies have attempted to quantify a lack of refueling availability as a penalty against the purchase price of a new vehicle. This quantification is used in discrete choice models representing how consumers weigh the advantages and disadvantages, or preferences and dislikes, when considering the purchase of a new vehicle. If the vehicle is an alternative fuel vehicle and consumers are aware of the degree to which refueling availability may be limited, a "rational model" of the vehicle purchase decision process suggests that this penalty would be a function of either the percentage of stations offering the fuel in the consumer's urban area or the additional distance or searching time that a consumer would travel or spend finding a refueling location. The wide variation in results and analytical approaches associated with penalties for limited refueling availability is shown in Figure 2.9. There is a tendency for analytical approaches (based upon travel models and value-of-time estimates) to give lower penalties than those from stated preference surveys.

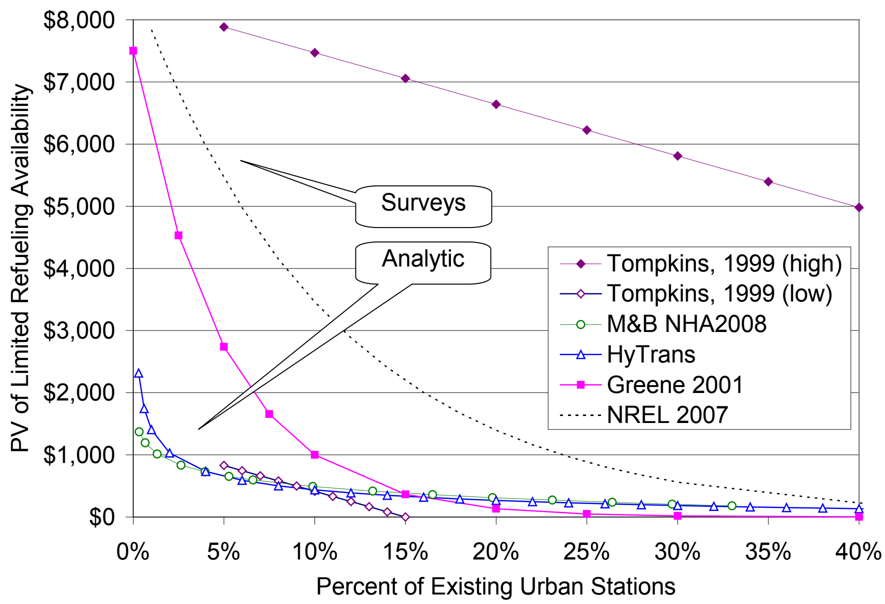


Figure 2.9. Present value of the real or perceived penalty against the purchase price of a new dedicated vehicle (e.g., hydrogen FCEV) as a function of the percentage of urban fueling stations offering fuel

(Source: Melaina 2009)

"M&B NHA2008" is based upon Melaina and Bremson (2008); "NREL 2007" is based upon a survey study reviewed in Melaina et al. (2012); "HyTrans" penalties are derived from results presented in Nicholas et al. (2004).

One study of coverage requirements assesses the average travel time for all residents in a given urban area to drive from their place of residence to a fueling station location. Using a detailed traffic model and a location optimization routine, Nicholas and Ogden (2006) examined the variation in average travel times across four major California urban areas. These results can be interpreted as follows:

- In the case of Sacramento, with a population density of 3,768 persons per square mile, coverage equivalent to 2% of existing gasoline stations would allow all residents in the urban area, on average, to reach a fueling station within seven minutes of their place of residence. If coverage were equivalent to about 16% of existing gasoline stations, this average travel time would be three minutes for all residents.
- By comparison, in Los Angeles, with a population density of 5,421 persons per square mile, coverage equivalent to approximately 7% of stations would correspond to an average travel time of three minutes.

The researchers note that additional stations beyond those needed to achieve an average travel time of approximately three minutes have a diminishing effect on reducing the average travel time in any given urban area. A similar analytic approach is being pursued to plan retail station rollouts in California using the University of California Irvine STREET model (Stephens-Romero et al. 2010). In a complementary study, Melaina and Bremson (2008) estimate the degree to which some U.S. urban areas appear to have an excess of gasoline stations per square mile and propose an upper threshold of stations needed in an urban area as a function of population density. Combined, these studies provide a theoretical portrait of retail fuel sector expansion requirements associated with sufficient provision of alternative fuels for both early markets and large-scale deployment (cf. National Research Council 2009, pg. 237). General trends revealed in the results of these studies are used in evaluating LDV retail infrastructure expansion requirements in Section 4.4.

2.2. Experiences from International CNG Programs

Alternative fuel retail infrastructure has been installed internationally. Selected international experiences with CNG infrastructure expansion are reviewed below with respect to network expansion, vehicle market growth, and policy support mechanisms. CNG station installations are the focus here because they are perhaps the most noteworthy as examples of expansion of infrastructure that significantly differs from gasoline station equipment. International efforts to deploy other alternative fuels have been discussed elsewhere (Sperling and Gordon 2010; Goldemberg 2006).

In a review of international efforts to adopt CNG vehicles, Yeh (2007) suggests that a vehicle-to-refueling station index (VRI) metric has significant explanatory power for successful market adoption. As shown in Figure 2.10, temporal trends indicate which countries have approached or exceeded a ratio of 1,000 CNG vehicles per fueling station (Brazil, Italy, India and Argentina). Countries in which this ratio has not been reached have generally not seen market take-off (New Zealand, China, United States). Difficulties with the Canadian CNG experience were reviewed by Flynn (2002). New Zealand is unique in having reversed its move toward CNG market adoption, while Argentina's CNG market has thrived based upon a unique mix of policy support mechanisms. Both cases, which are reviewed in more detail below, suggest the degree to which strong policy support complements even favorable market conditions. The VRI metric is interesting as a measure of retail availability that sustains widespread market adoption, in contrast to the sufficient geographic coverage metric, which addresses coverage to support early market growth. As shown in Figure 2.10, Brazil and India started market growth with relatively low VRI values; early market VRI values are not shown for Argentina and Italy. The last year indicated for Italy, 2004, reflects a drop in the VRI from just over 1.2 to approximately 0.85 due to an increase in CNG stations. This year also indicates a slight reduction in natural gas vehicles as a percent of all vehicles relative to 2001, the previous reported year.

The VRI values shown for "U.S. conventional" indicate the number of conventional gasoline vehicles per gasoline refueling outlet, with the VRI increasing gradually from 0.99 to 1.39 between 1995 and 2002. This increase is due to a gradual decline in the number of gasoline stations and an increase in the total number of gasoline LDVs. As a more recent point of reference, 240 million LDVs were supported by approximately 159,000 conventional stations in the United States in 2010, resulting in a VRI of 1.51. However, rather than increasing monotonically, this value has fluctuated between 1.45 and 1.55 since 2006 (Davis et al. 2012, Table 4.18).

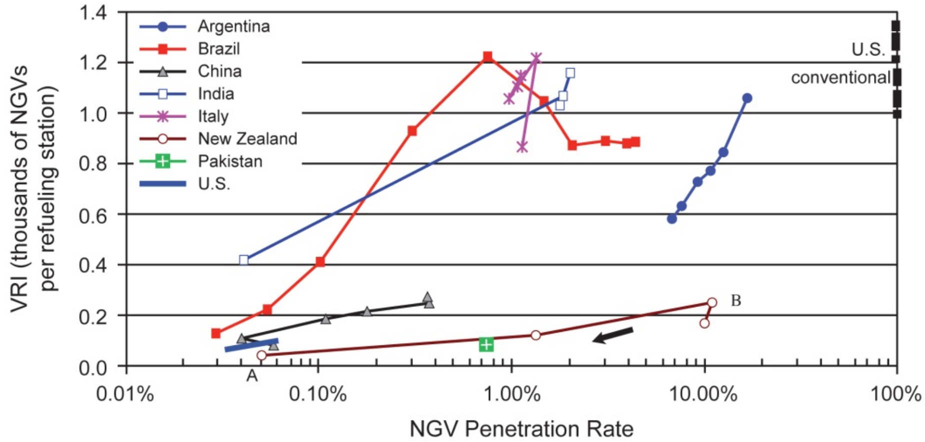


Figure 2.10. Vehicle-to-refueling-station index (VRI) and natural gas vehicle market penetration as share of total vehicle fleet for select countries

(Source: Adapted from Yeh 2007)

An aggressive CNG program was launched in New Zealand in 1979 with a goal of converting 150,000 vehicles to operate on CNG by 1985 (later revised to 200,000 vehicles by 1990). By 1986, seven years after the program was launched, 110,000 CNG vehicles had been converted and were served by 400 fueling stations (Sathaye et al. 1989, pg. 2). Actions taken by the New Zealand government included the following:

- Establishment of a series of standards for vehicle conversions and fueling stations.
- Creation of a CNG Coordinating Committee to provide guidance on technical and regulatory challenges.
- Creation of a grant program for conversion kits, which paid NZ$200 per kit until 1983, then increased to NZ$500–$5,000 per kit, with a lower interest rate of 10%, starting in 1983. Sathaye et al. (1989) report that the average payback time for vehicle conversions, taking into account grants, was approximately two years.
- Offer of a 25% grant for both fueling station equipment and expenditures related to CNG.
- Tax write-offs given for vehicles converted in factories.
- Implementation of a low fuel tax for CNG.
- Active promotion of CNG and "encouragement" to retailers to keep CNG at half the price of gasoline (New Zealand was natural gas-rich at the time).

Additionally, a CNG industry group offered consumers free fuel vouchers for up to NZ$300 for the first two years after converting a vehicle.

As reported by Kurani (1992), consumer acceptance was limited early on by the lack of CNG fueling stations, but acceptance increased as more stations were installed and the fraction of total retail stations offering CNG approached 10%. CNG vehicles accounted for 11% of on-road LDVs by 1986 (see Figure 2.10), and CNG displaced some 875,000 barrels of gasoline in 1985 (Sathaye et al. 1989). A new government in 1985 reduced support for the conversion loan program, increasing the interest rate and limiting the number of loans per month. Combined with the drop in world oil prices in 1986, this dampened growth in CNG vehicles and stations. The government attempted to revive the program in 1986, but market growth stagnated with continued decline in the price of oil. A cost-benefit analysis by

Sathaye et al. (1989) indicates that, overall, the program provided benefits to New Zealand when assuming 1985 gasoline prices, but it struggled to break even with lower gasoline prices after 1985.

After the discovery of large natural gas reserves in the early 1980s, Argentina policymakers began to examine the potential role of natural gas vehicles as an alternative to petroleum fuel imports. In 1983, Argentina's Secretary of Energy established a committee to consult on the deployment of natural gas vehicles and infrastructure. The committee made recommendations on rules, codes, and standards for natural gas vehicle conversions and fueling equipment, resulting in a national implementation plan and established codes and standards, both in 1984. A pricing policy set CNG to 45% of the price of premium gasoline, starting in 1985. In 1987, the president of Argentina formally decreed CNG a matter of national interest (Collantes and Melaina 2011). Although the original target market was heavy-duty diesel vehicles, the market where CNG vehicles took hold was fleet LDVs, and taxicabs in particular. A loan program was established for taxicab drivers to finance vehicle conversions, with fuel savings contributing to paying off the loans. By the mid-2000s, gasoline consumption had declined and CNG vehicle fuel use approached total gasoline consumption on an energy basis, and by 2007 the total number of CNG retail stations exceeded 1,600. It is estimated that Buenos Aires had an approximate density of 0.3 station per square mile, which is roughly half the density of gasoline stations in major U.S. cities (Melaina and Bremson 2008). As shown in Figure 2.10, Argentina reached a VRI of 1.0, equal to 1,000 natural gas vehicles per refueling station, shortly after a 10% market penetration. Aside from the work on codes and standards, direct financial support for CNG infrastructure in Argentina was minimal during the early market growth period and expansion largely continued due to pricing policies that influenced both the financing of vehicles and the relative price of CNG compared to gasoline (Collantes and Melaina 2011).

These international experiences with alternative fuel infrastructure took place under unique conditions and do not necessarily imply that similar policy support or economic conditions would lead to success in the Unites States. However, they do provide some reference for the timing and retail-station infrastructure expansion for introduction of new fuels. Although the outcomes were very different, both programs relied upon strong government support and a mix of policies and initiatives, and both were highly susceptible to the influence of the price differential between CNG and gasoline.

3. Low-Carbon Fuel Scenarios

Different combinations of low-carbon fuels could be used to reduce GHG emissions to 80% of 2005 levels by 2050; however, each fuel has different infrastructure characteristics. This section reviews input assumptions about reductions in demand intensity and energy intensity for the low-carbon scenarios, and then provides details on the combinations of low-carbon fuels assumed for each scenario. In general, the different combinations of fuel volumes and associated fuel carbon intensities that reduce transportation sector 2050 GHG emissions by 80% fall within a relatively well defined range. This can be demonstrated in a simplified manner for each transportation market segment using metrics for activity (α), end-use efficiency (η) and fuel carbon intensity (FCI):

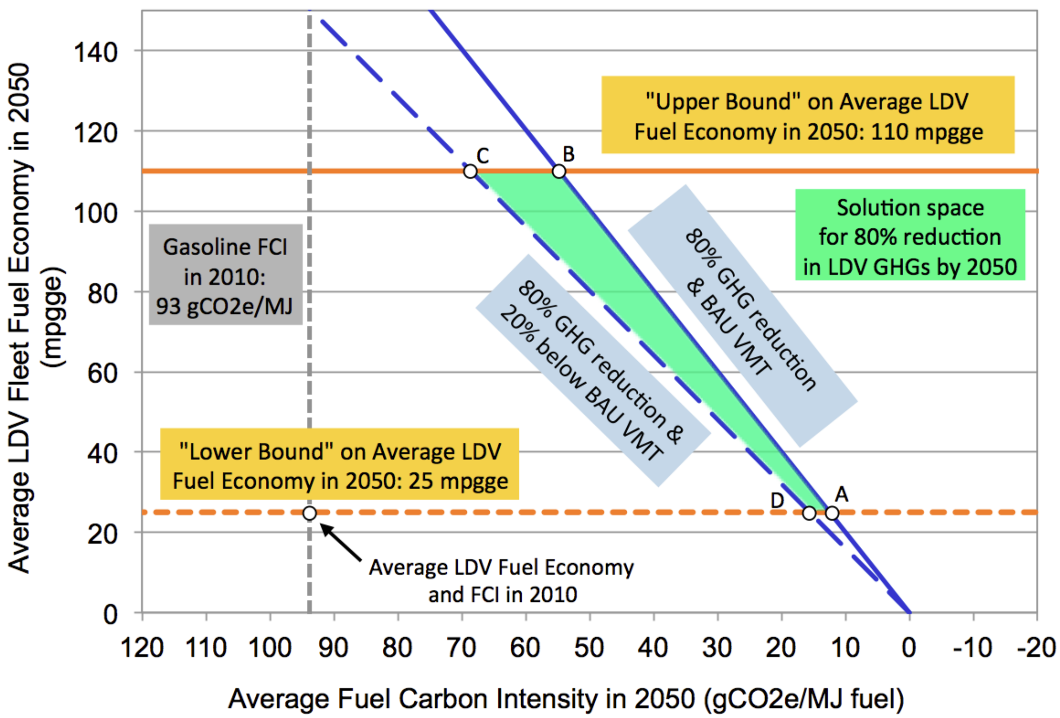
$$GHG = \alpha \cdot \eta \cdot FCI$$

The measure of activity (or demand intensity) for LDVs and M/HDVs is typically expressed in VMT/yr and end-use efficiency (or energy intensity) is expressed in mpgge. For the air market segment, activity is measured in seat-miles traveled and end-use efficiency is measured in seat-miles per gallon gasoline equivalent. In all market segments, the units for FCI are expressed in grams of CO_2 equivalent GHG emissions per megajoule (MJ) of fuel consumed (gCO_2e/MJ), using the higher heating value of each fuel. Similar approaches to decomposing the 2050 GHG goal for the transportation sector have been discussed elsewhere (Yang et al. 2008; Leighty et al. 2012; Melaina and Webster 2011).

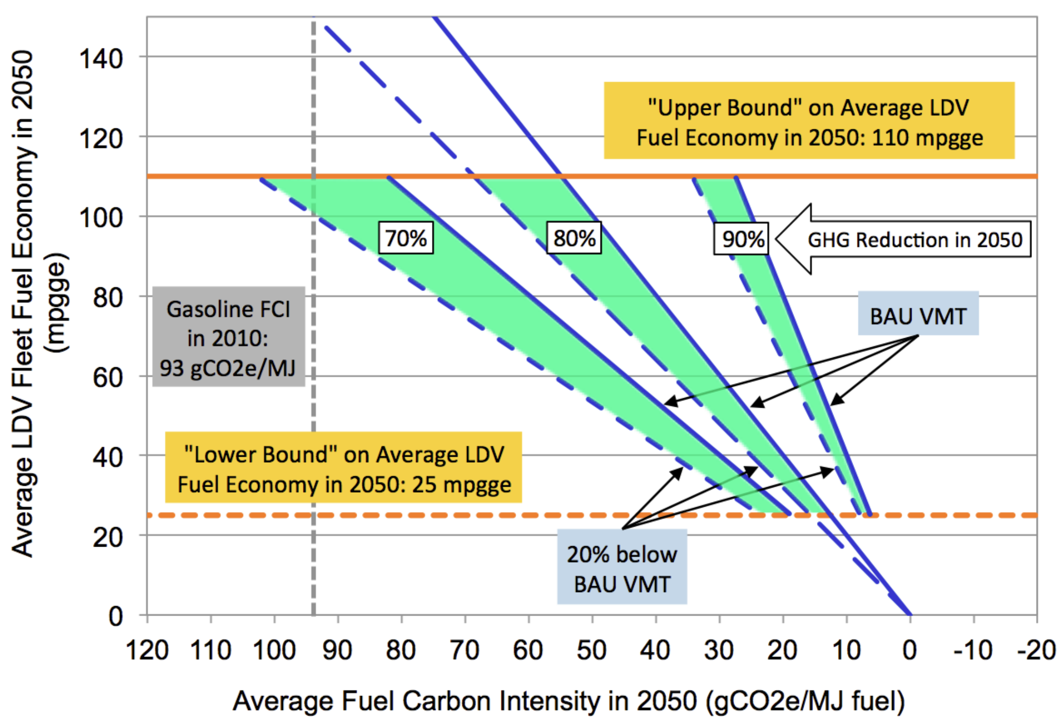
Using the BAU scenario trends underlying the GHG projections shown in Figure 1.1 as a reference, we can infer from this simple equation to what degree each of the three variables would have to change to reach an 80% reduction in GHG emissions. Figure 3.1a shows the resulting feasible solution space for the LDV market segment. The area highlighted in green includes all feasible outcomes that reach an 80% GHG emission reduction by 2050. The vertical axis indicates the average fuel economy of the on-road LDV fleet, with 25 mpgge being a nominal "lower bound" in 2050 and 110 mpgge serving as a nominal "upper bound" in 2050. The horizontal axis indicates FCI declining to zero toward the right hand side of the figure. As a reference, the FCI for gasoline in 2010 is indicated as a vertical dashed grey line, and the intersection of gasoline FCI and average on-road LDV fuel economy in 2010 is indicated as a point. The two diagonal blue lines are bounds on potential activity levels (measured in VMT) for LDVs in 2050. The solid blue diagonal line is the BAU projection for VMT in 2050 (5.05 trillion miles traveled), and the dotted blue line is a 20% reduction below this VMT level by 2050. This shaded green area, indicating the solution space, can be interpreted as follows. If projected BAU VMT growth trends prevail through 2050 and no major improvements in LDV fuel economy take place by 2050, average FCI would have to be reduced to approximately 12 gCO_2e/MJ to meet the 2050 80% GHG goal. This extreme solution to the GHG goal is represented by point A in Figure 3.1a. If VMT trends prevail but LDV fuel economy increases dramatically such that average on-road fuel economy reaches 110 mpgge, then the average FCI would need to be reduced to approximately 55 gCO_2e/MJ (point B). Alternatively, if VMT growth trends are dampened and total VMT are 20% lower than the BAU value for 2050, average FCI reductions do not need to be as deep, indicated by points C and D. Any point within the green-shaded solution space meets the 80% GHG reduction goal by 2050 with some combination of LDV demand intensity (α), energy intensity (η), and FCI.

Figure 3.1b shows the same LDV 80% GHG emission reduction solution space, as well as solution spaces for 70% and 90% GHG emission reductions by 2050. This comparison, keeping LDV fuel economy and VMT constant, highlights the degree to which FCI reductions would need to be relied upon to meet a range of possible GHG reduction levels. As indicated, no gasoline FCI reductions would be required to meet a 70% GHG emission reduction goal by 2050 if average on-road fuel economy exceeded 100 mpgge and VMT were reduced by 20% below the BAU projection. Figure 3.2 and Figure 3.3 portray similar feasible solution spaces for M/HDVs and commercial aircraft, with corresponding nominal upper and lower bounds on fuel intensity and demand intensity. The upper bounds on fuel intensity are aggressive, and distinct opportunities for improvement are discussed elsewhere (Vyas et al. 2013).

This simple algebraic exercise begins to reveal the range in the extent to which low-carbon fuel strategies could be relied upon to reach deep reductions in 2050 GHG emissions in the transportation sector. The role of low-carbon fuels is explored in detail in the Portfolio, Combustion, and Electrification scenarios. As summarized in Table 1.1, these scenarios include distinct market shares of advanced LDVs and different fuel production types across all market segments. Section 3.1 reviews the distinct combinations of demand intensity reductions and end-use efficiency improvements associated with each scenario. Section 3.2 examines low-carbon fuel supply options that are then used to reach the additional GHG reductions to meet the 2050 GHG goal. While the fuel supply trends included in each scenario are not optimal or necessarily equally feasible, they represent a range of possible options for fuel supply infrastructure expansion. The internal consistency achieved by decomposing assumptions about market and technology development trends underlying these three key metrics (α, η, and *FCI*) allows for a more detailed evaluation of the scenarios in Section 4.



(a)



(b)

Figure 3.1. Feasible solution space for LDVs in 2050: (a) fuel economy and FCI, and (b) feasible solution spaces for LDVs at 70%, 80% and 90% GHG reductions by 2050

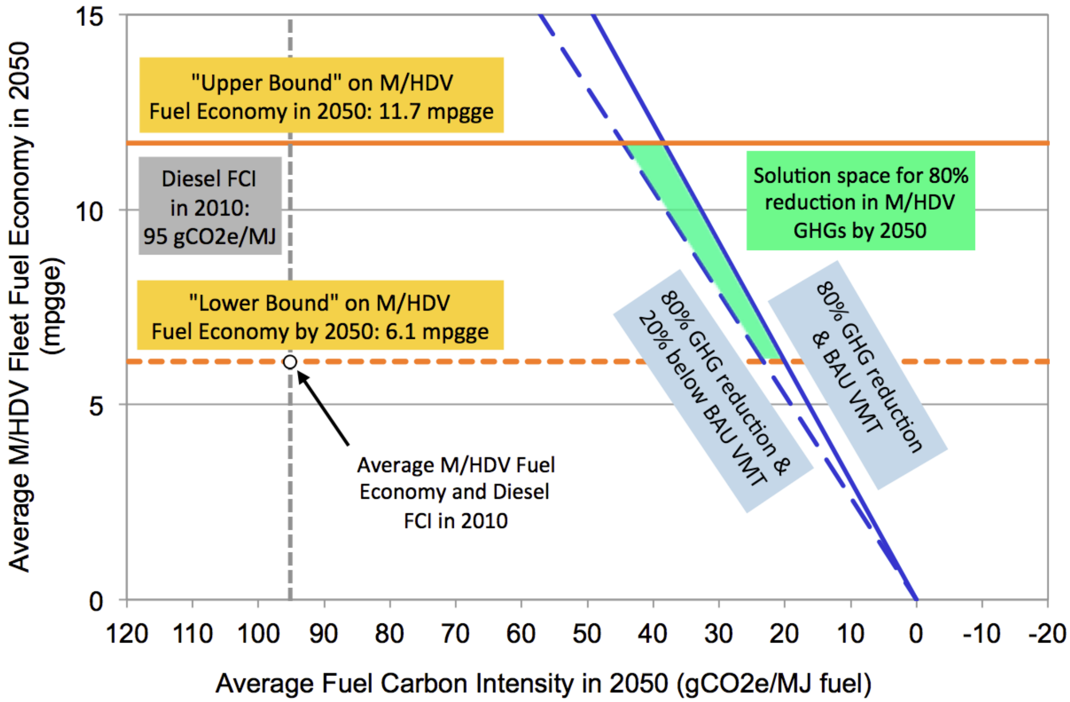


Figure 3.2. Feasible solution space for M/HDVs in 2050: Fuel economy and FCI

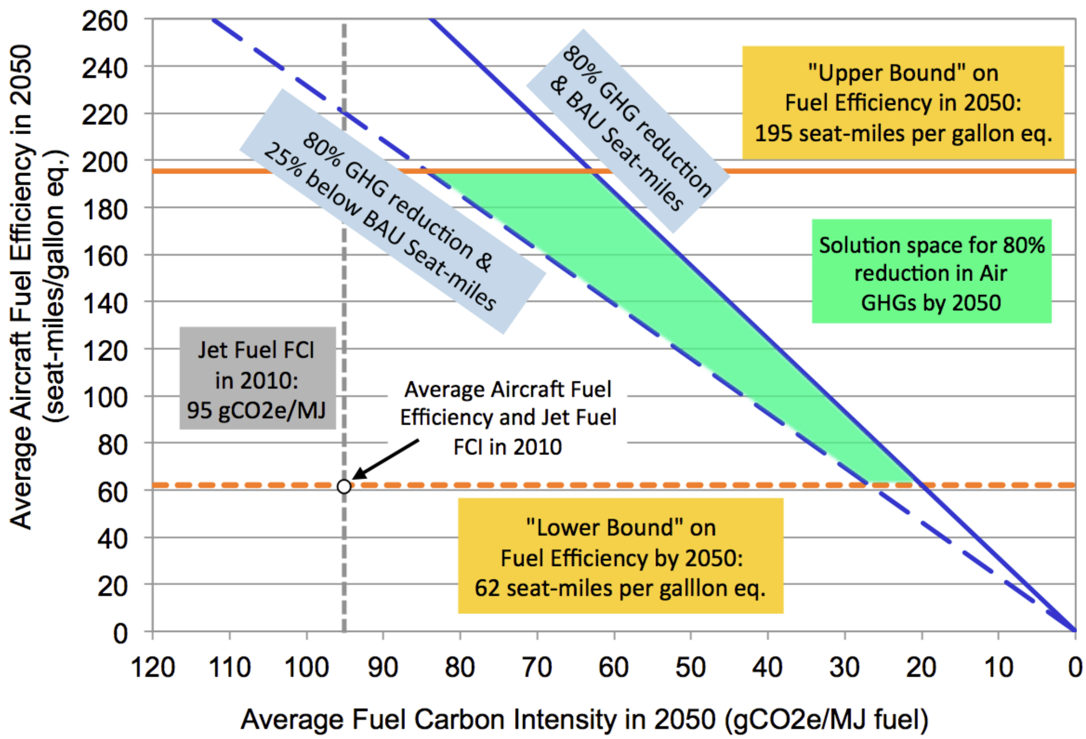


Figure 3.3. Feasible solution space for aircraft in 2050: Seat-miles per gallon of fuel and FCI

3.1. Transportation Demand Intensity and Energy Intensity Reductions

The low-carbon scenarios assume significant reductions in transportation demand and in the energy intensity of end-use vehicles. Compared to the BAU scenario, all three low-carbon scenarios assume a 10% reduction in LDV VMT and a 15% reduction in M/HDV VMT, as shown in Figure 3.4. Demand in other transportation markets is assumed to be equal to the BAU scenario. This demand intensity reduction is based upon results from parallel reports on demand reduction conducted for the Transportation Energy Futures (TEF) study (Grenzeback et al. 2013; Vyas et al. 2013). Aggressive energy intensity improvements in NLDV sectors have also been estimated for the TEF project (Vyas 2011) and are summarized in Figure 3.5. These NLDV energy intensity reductions are assumed for each of the three low-carbon scenarios. Similarly, new LDV vehicle fuel economies, by drivetrain type, are assumed to improve at the same rate for all three low-carbon scenarios, as shown in Figure 3.6 and Figure 3.7. The main difference across the three low-carbon scenarios is the variation in the market share of LDVs. These market shares are compared alongside the BAU scenario market shares, in Figure 3.8, Figure 3.9, Figure 3.10, and Figure 3.11. As discussed earlier, the Combustion scenario tends to rely upon LDVs that use biofuels and CNG/LNG, the Electrification scenario tends to rely upon LDVs that use hydrogen and electricity, and the Portfolio scenario is a combination of multiple types of LDVs. The LDV platforms in the analysis include the following:

- BEV
- Spark ignition PHEV
- Fuel cell vehicle
- Diesel HEV
- Spark ignition HEV
- Diesel
- CNG
- Flex-fuel vehicle (E85 capable)
- Gasoline internal combustion engine.

Figure 3.12 summarizes the implications of these demand and efficiency assumptions for reducing fuel use (a) and reaching the 2050 GHG goal (b). The solid black line indicates BAU GHG emissions. The dashed blue line, just below the BAU line, shows the reductions in fuel use and GHG emissions that would result from the demand intensity reductions for LDVs and M/HDVs discussed above (see Figure 3.4). The dotted red line indicates the additional reductions that would result from the end-use efficiency improvements across all NLDV market segments (see Figure 3.5). Beyond these demand and NLDV efficiency assumptions, end-use efficiency improvements in the LDV segment in each scenario bring total 2050 fuel use down to 112–122 billion gallons of gasoline equivalent energy (BGGE) and GHG emissions down to approximately 1,400–1,500 $MMTCO_2e$. To meet the 2050 GHG goal, another 1,900–2,000 $MMTCO_2e$ would need to be reduced through use of low-carbon fuels.

The demand and efficiency reductions shown in Figure 3.12b can also be expressed in terms of the degree to which each reduction type closes the gap between BAU GHG emissions in 2050 and the 2050 goal. Demand reduction alone reduces the gap by 10%, and NLDV efficiency improvements reduce the gap by an additional 22%. LDV efficiency improvements for the Portfolio, Electrification, and Combustion scenarios each reduce the gap by an additional 31%, 31%, and 36%, respectively. Therefore, the gap remaining to be closed by low-carbon fuels is 32%–37% of the total GHG emission reductions required by 2050. The GHG reductions due to LDV efficiency are nearly identical in the Portfolio and Combustion scenarios. The GHG reductions in the Electrification scenario are not as deep, even though fuel use reductions due to LDV efficiency are greater than in the Portfolio and Combustion scenarios (Figure 3.12a). The higher GHG emissions in the Electrification scenario shown in Figure 3.12b are due, in part, to the higher carbon intensity of the grid (BAU power generation mix) and hydrogen (produced primarily from natural gas in BAU) before incorporating scenario assumptions about low-carbon fuels.

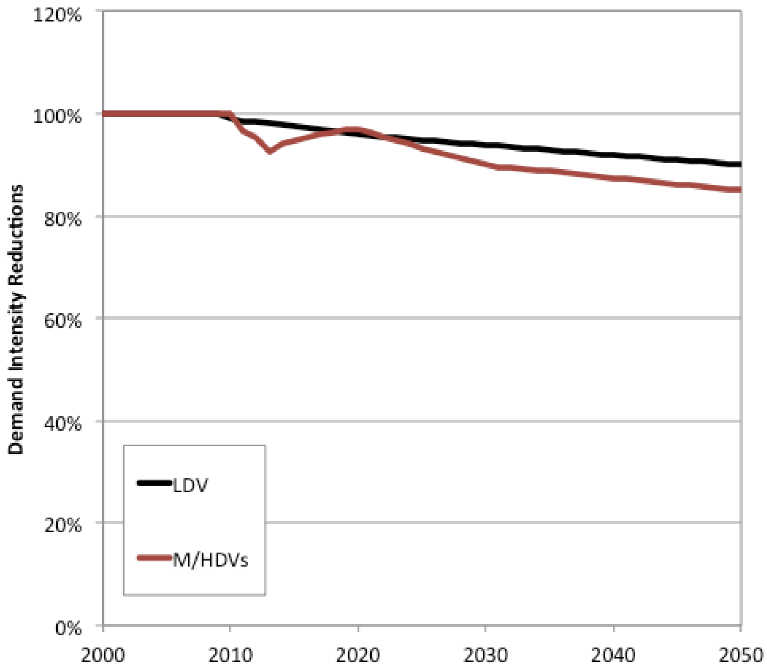


Figure 3.4. Demand intensity reductions for LDVs and M/HDVs, shown as a ratio of low-carbon scenario VMT to the BAU VMT

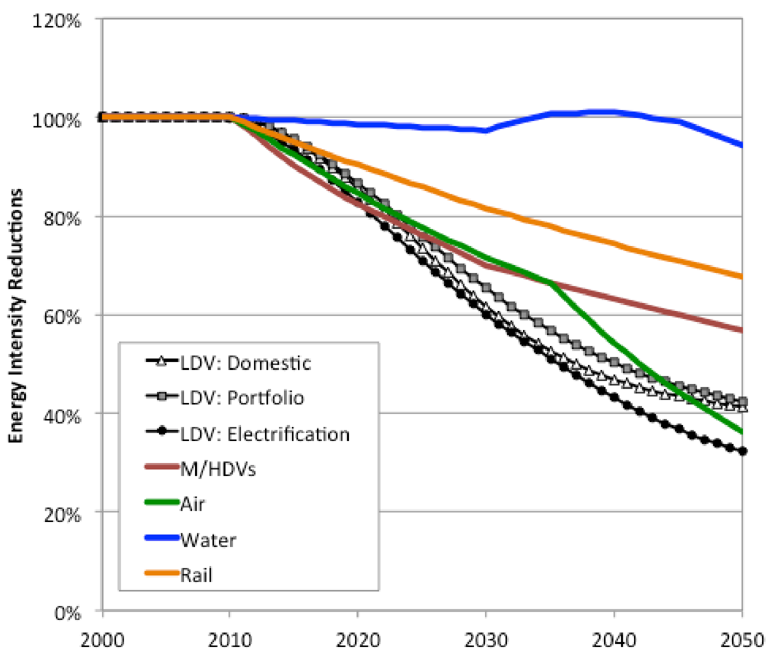


Figure 3.5. Energy intensity reductions for M/HDV, air, water, and rail sectors, and three LDV scenarios

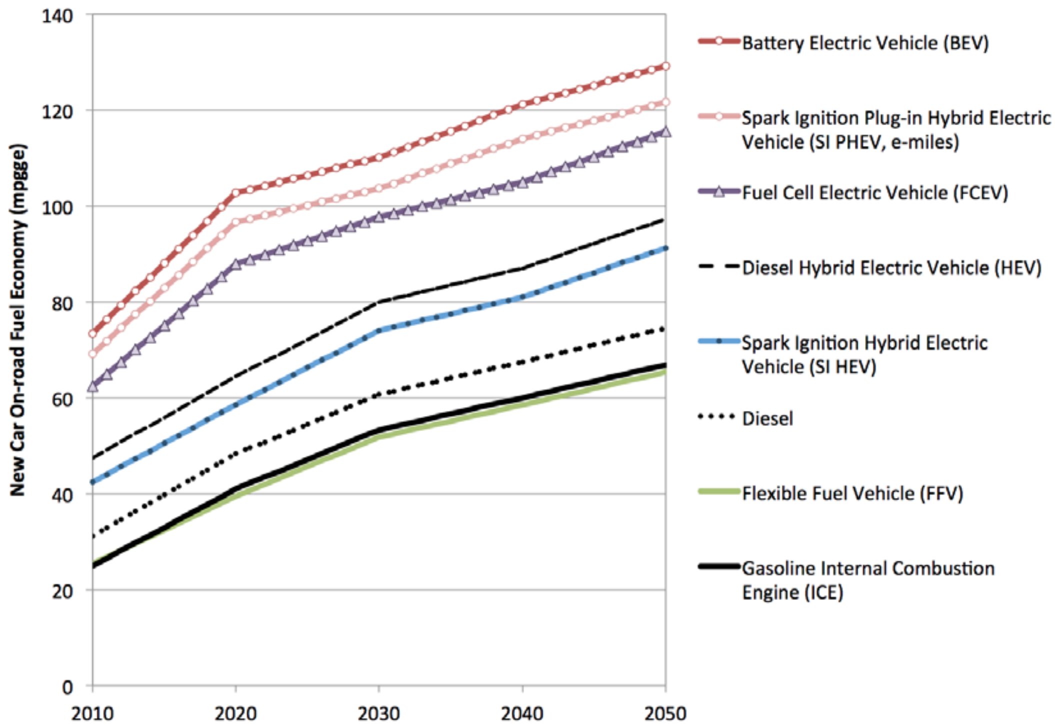


Figure 3.6. New car on-road fuel economy for the low-carbon scenarios

Note: PHEV gasoline miles have a fuel economy that is equivalent to spark ignition (SI) HEVs.

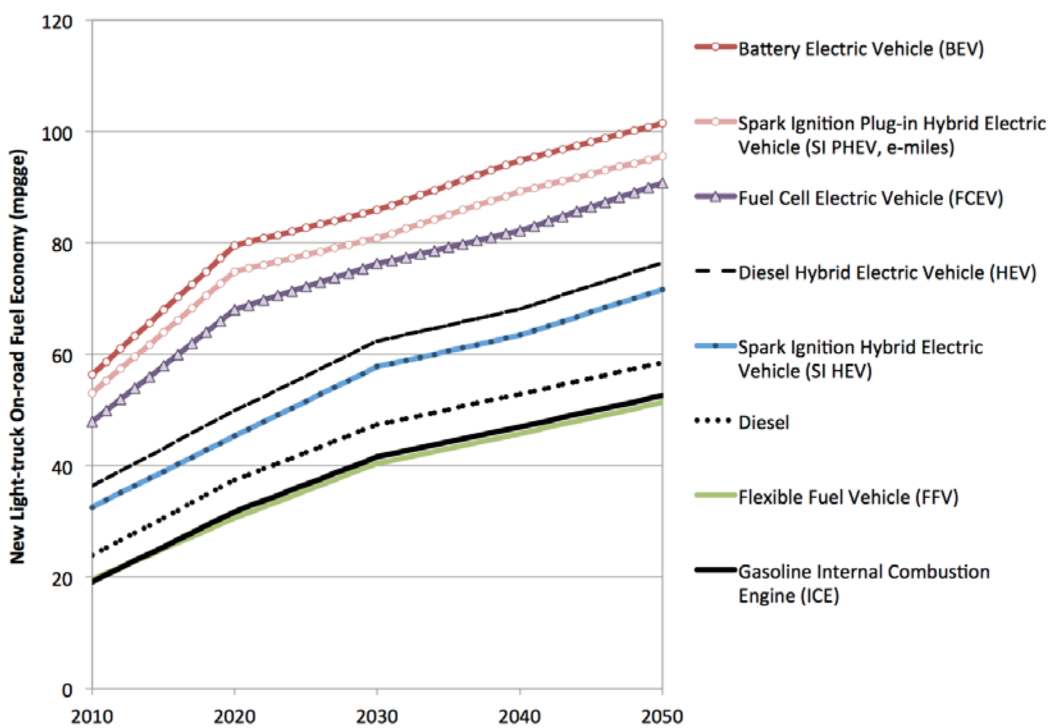


Figure 3.7. New light truck on-road fuel economy for the low-carbon scenarios

Note: PHEV gasoline miles have a fuel economy that is equivalent to spark ignition (SI) HEVs.

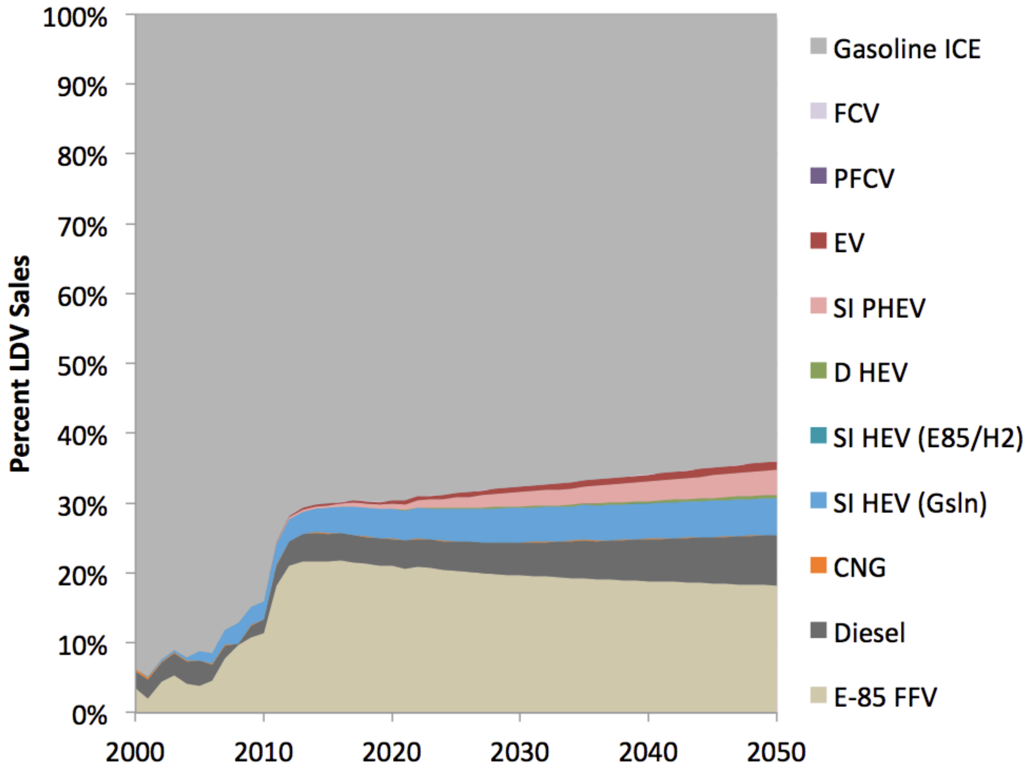


Figure 3.8. New LDV market shares for the BAU scenario

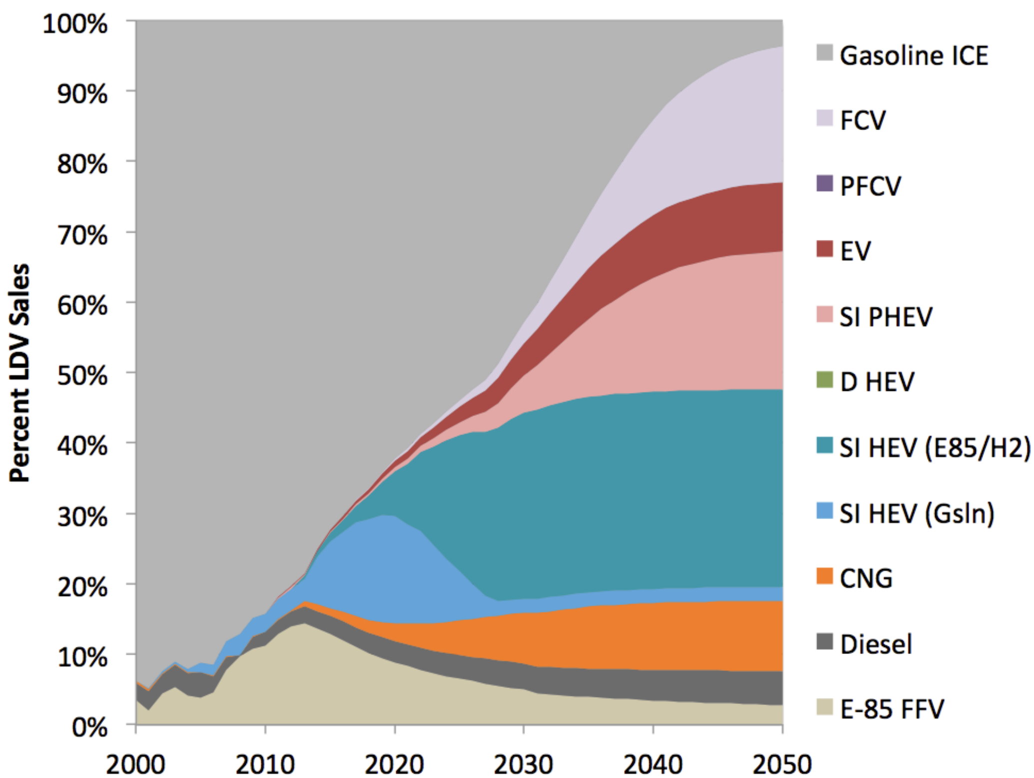


Figure 3.9. New LDV market shares for the Portfolio scenario

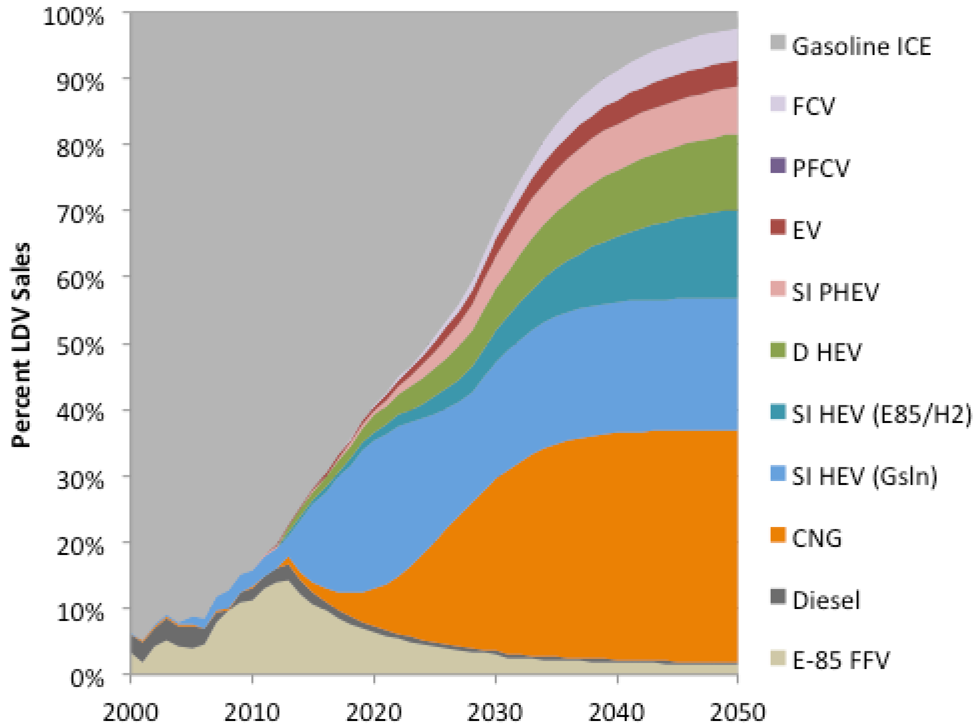


Figure 3.10. New LDV market shares for the Combustion scenario

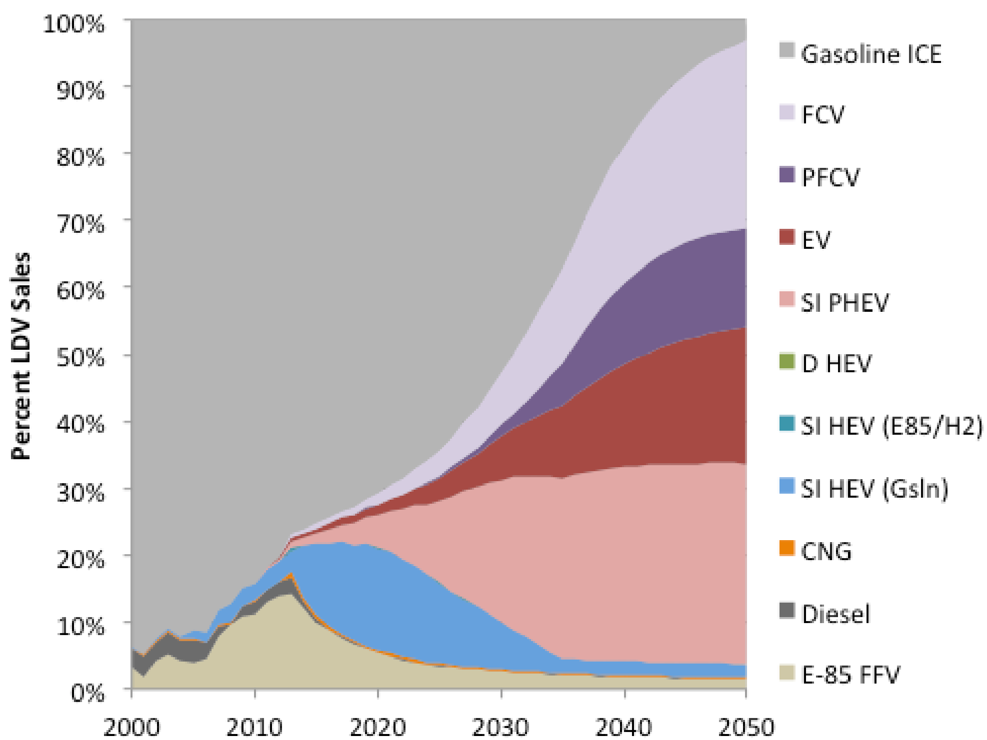
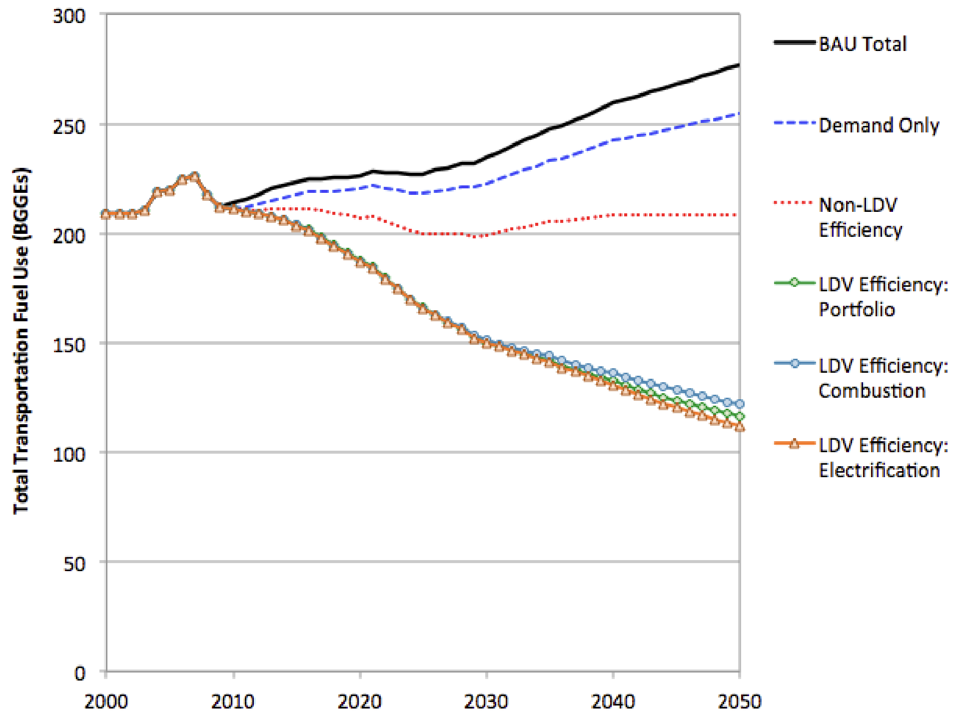
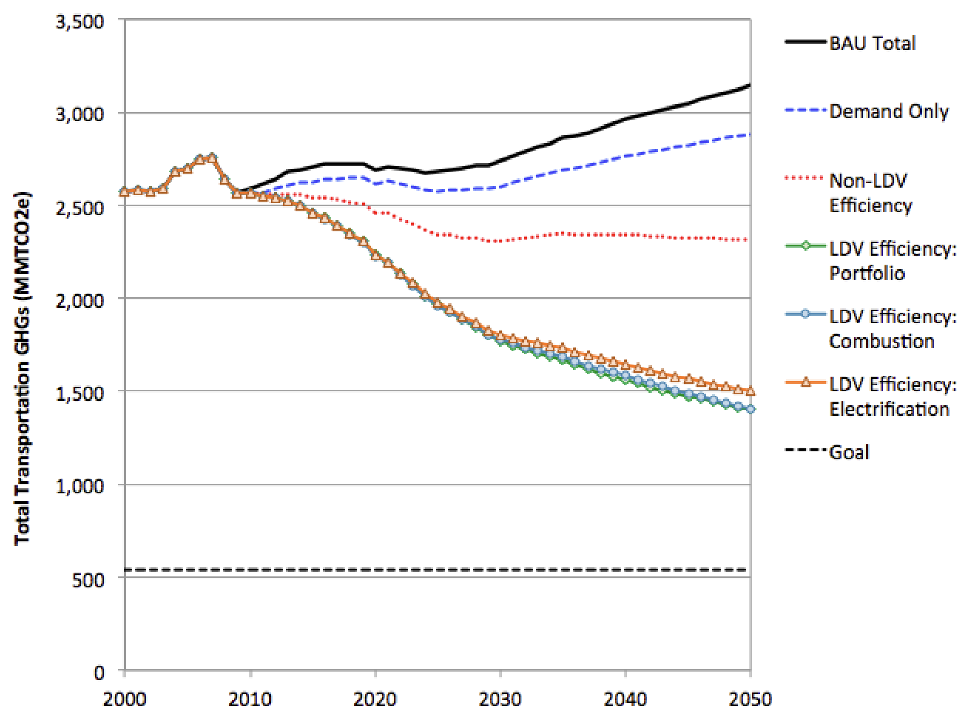


Figure 3.11. New LDV market shares for the Electrification scenario



(a)



(b)

Figure 3.12. Fuel use reductions (a) and GHG reductions (b) due to demand reductions and efficiency improvements, and with carbon intensities of conventional fuels

Conventional fuels are gasoline with corn ethanol blend for internal combustion engines, BAU grid electricity for PEVs, and hydrogen from natural gas for fuel cell vehicles. GHG reductions in (b) for the Portfolio and Combustion scenarios are nearly identical, and are approximately 6.5% lower than the total GHGs in the Electrification scenario.

These demand reductions, end-use efficiency improvements, and LDV market share values begin to highlight the similarities and differences between the three scenarios. Figure 3.13 clarifies distinctions among LDV fuel options by indicating total VMT by fuel type for all LDVs in 2050. All three low-carbon scenarios have a 10% reduction in total LDV VMT compared to BAU VMT, and the BAU scenario is 85% fossil fuel miles, including gasoline from conventional and unconventional petroleum resources. Biofuel VMT are half or more of total VMT in both the Portfolio and Combustion scenarios, and approximately one quarter of total VMT in the Electrification scenario. CNG fuels a large fraction of total VMT in the Combustion scenario and a smaller but still significant share in the Portfolio scenario. Hydrogen and electricity are used for more than half of all VMT in the Electrification scenario, and about one-third of VMT in the Portfolio scenario. The next section outlines combinations of fuels within each scenario, and how fuel types with particular FCI reductions help reach the 2050 GHG reduction goal.

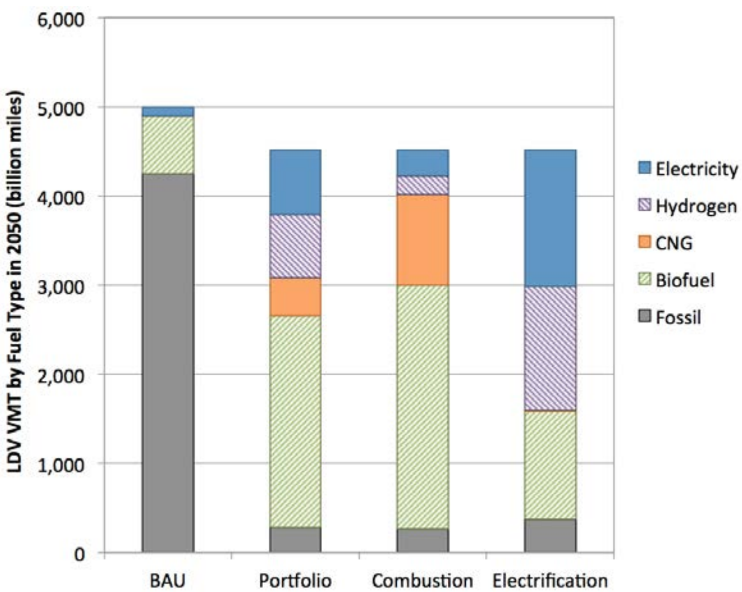


Figure 3.13. LDV VMT by fuel type in 2050

3.2. Fuel Volumes and Sufficient Life Cycle Fuel Carbon Intensities

Total life-cycle FCIs, measured in gCO_2e per MJ of fuel, have been projected to 2050 based upon two major fuel models, GREET (Argonne National Laboratory 2011) and GHGenius [(S&T)^2 Consultants], as well as a number of other sources. These models do not extend to 2050 in most cases so a number of assumptions have been made to project FCI values over time for each fuel, with most fuel characteristics remaining similar beyond about 2030 (see Appendix A). FCIs do not account for land use changes or other indirect impacts. As explained in Appendix A, this limitation of scope may be of particular concern for biofuels. Figure 3.14 shows the combination of fuels used in the BAU scenario, which can be compared to the fuel combinations assumed for each of the low-carbon scenarios in Figure 3.15, Figure 3.16, and Figure 3.17. The ramp-up rates for introducing low-carbon fuels in each of the low-carbon scenarios vary in terms of timing and magnitude; however, it is the total fuel volume and average FCI of each fuel type that determine whether the scenario reaches the 2050 GHG goal. The volume of each fuel type in 2050 is shown side by side for each scenario in Figure 3.18. The relative proportions among these fuels differ from the relative proportion of total VMT by LDV in Figure 3.13 due to the efficiency of the LDV fleet in 2050 and changes in fuel use within NLDV modes. As shown, fuel use in the Electrification scenario is slightly less than that in the Combustion scenario, which is slightly less than that in the Portfolio scenario. Fuel use in the Portfolio scenario is less than half that in the BAU scenario.

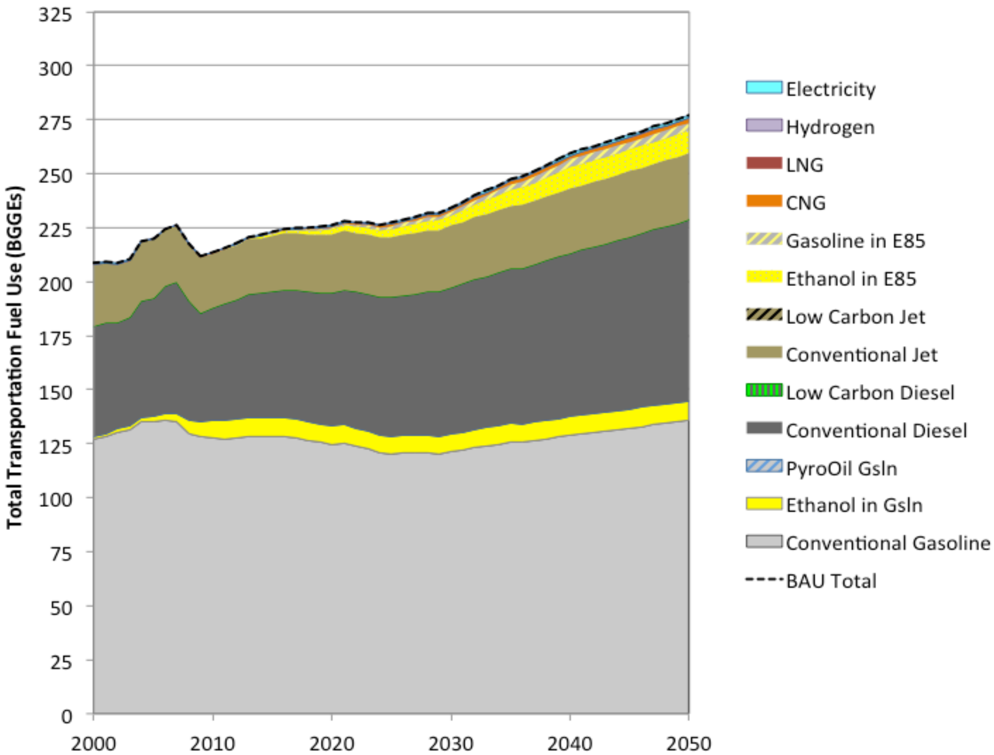


Figure 3.14. Total transportation fuel use in the BAU scenario

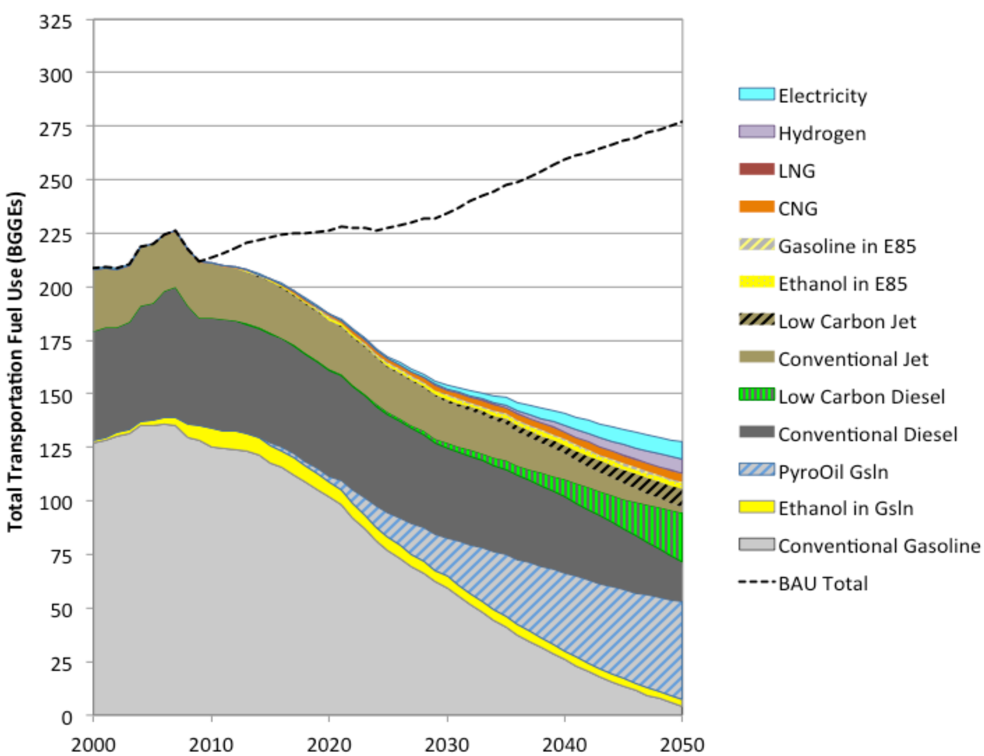


Figure 3.15. Total transportation fuel use in the Portfolio scenario

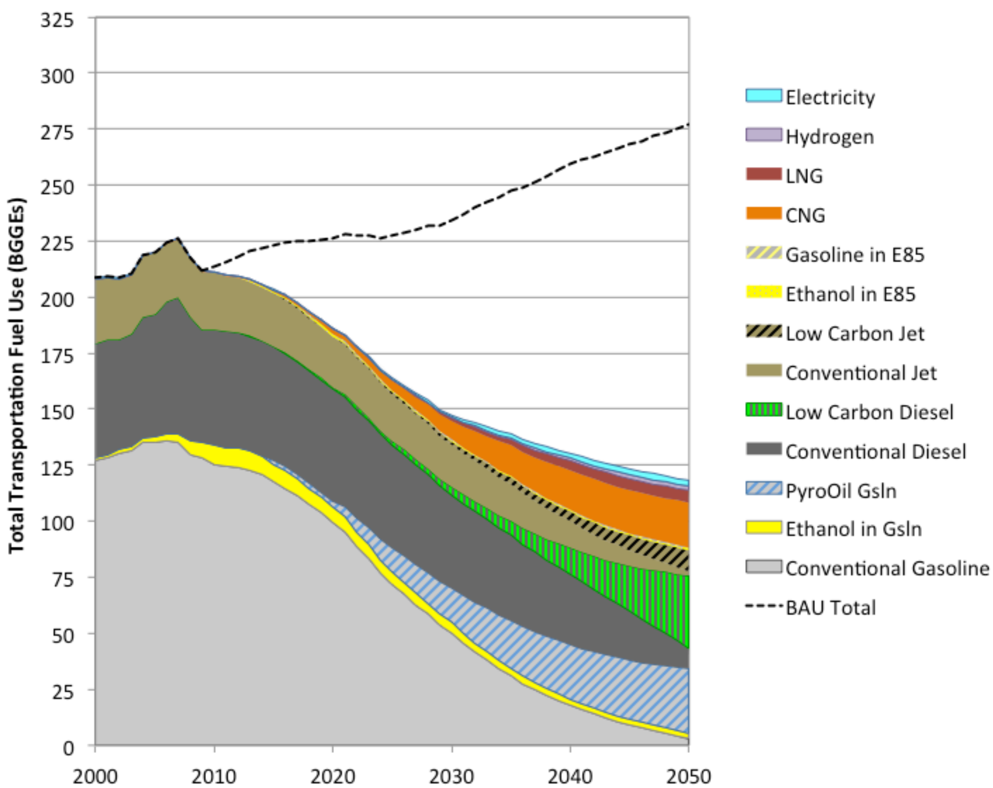


Figure 3.16. Total transportation fuel use in the Combustion scenario

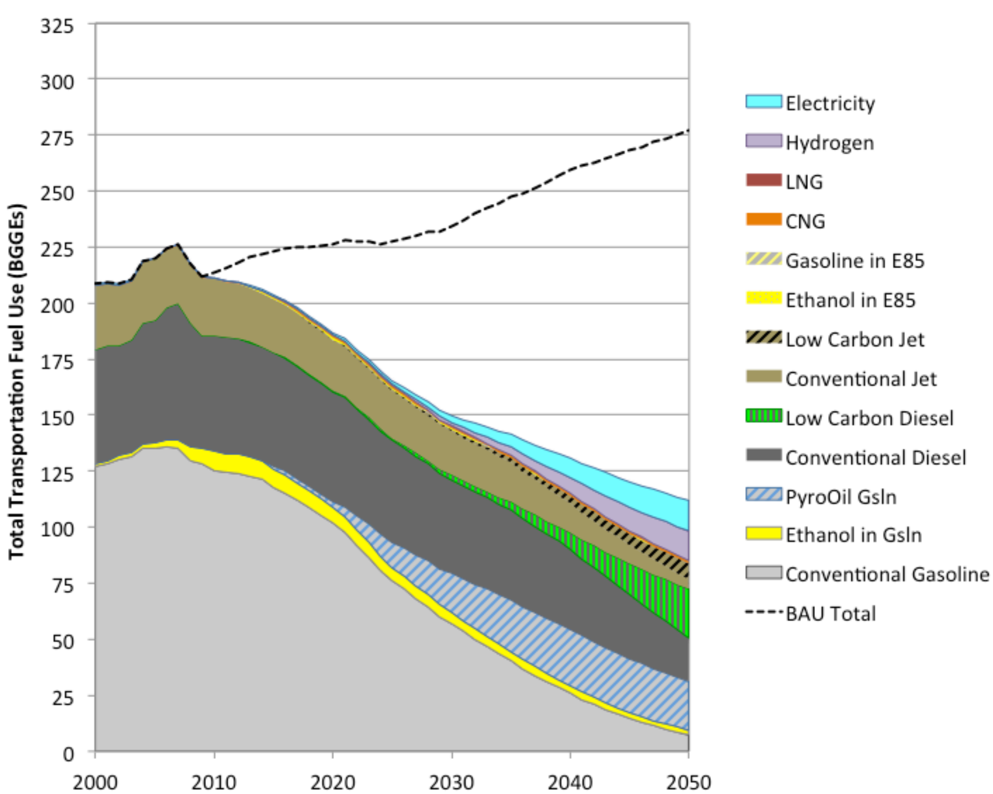


Figure 3.17. Total transportation fuel use in the Electrification scenario

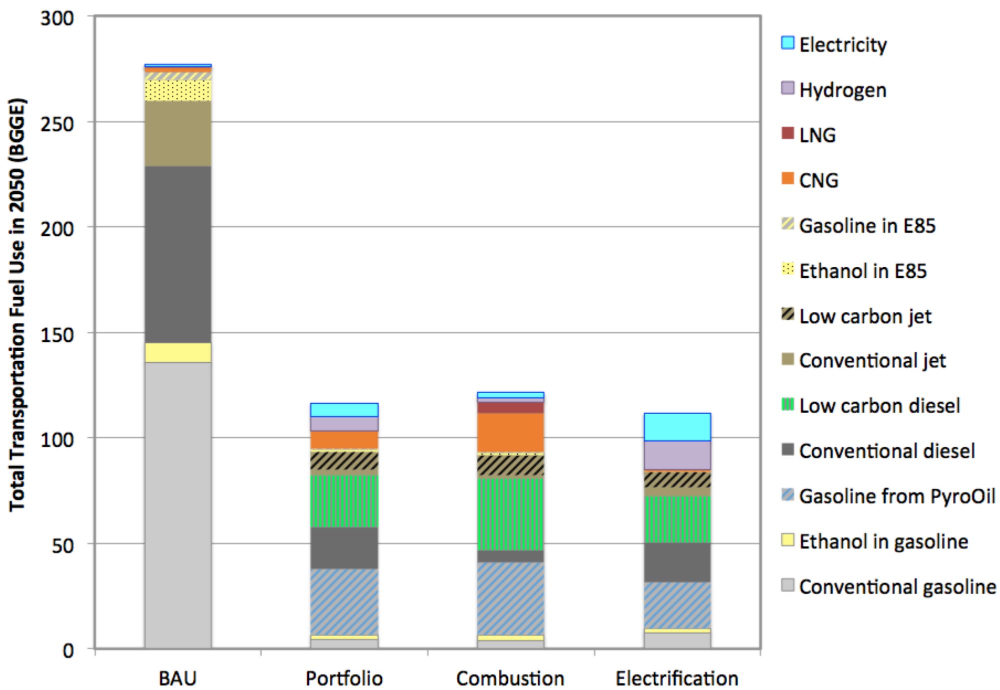


Figure 3.18. Volume of total transportation fuel use by scenario in 2050

The FCI values associated with these fuel volumes are sufficiently low to meet the 2050 GHG goal in each low-carbon scenario. The fuel volumes and sufficient FCI values for 2050 are compared between scenarios, and to the 2005 baseline fuels and 2050 BAU fuels, in Figure 3.19. The vertical axis is fuel volume in BGGE, and the horizontal axis is the average FCI for each (general) fuel type in gCO_2e/MJ. The total volume and average FCI of all fuels in 2005 and 2050 BAU are indicated by two points: 1) 2005 (solid black square) has a volume of 220 BGGE with an FCI close to that of conventional gasoline (including corn ethanol blend) and diesel fuels, and 2) 2050 BAU (open black square) has a volume of 273 BGGE with a slightly lower FCI due to larger volumes of low-carbon ethanol. The corresponding gasoline blends (grey solid and open squares) and diesel blends (green solid and open squares) have similar FCI values but lesser volumes. Volumes of CNG/LNG, hydrogen, and electricity are negligible in the 2005 Reference and 2050 BAU scenarios, and are shown for reference. Ethanol in 2050 is the exception, at 19 BGGE and an FCI of 26.5 gCO_2e/MJ. The total volume of all fuels in each of the low-carbon scenarios is on the order of that of gasoline or diesel alone for 2005 and 2050 BAU, at about 110–130 BGGE, and the average FCI for all fuels in these scenarios is about 60%–65% less than the average FCI in 2005. These values are shown by the black open diamond (Portfolio), circle (Combustion) and triangle (Electrification). This combination, a 40%–50% reduction in fuel use and a 60%–65% reduction in FCI, brings each of the low-carbon scenarios to the 2050 GHG goal for this analysis of 80% below 2005 GHG levels.

The lower right-hand corner of Figure 3.19 includes fuel volumes and FCI values for general low-carbon fuel types, and the same values are shown in detail in Figure 3.20. This framework for expressing fuel combinations that meet the 2050 GHG goal is useful in comparing fuel attributes across scenarios. First, demand for diesel fuel is relatively unchanged across the three scenarios. This result follows from the assumptions about nearly equivalent demand intensity and energy intensity reductions in NLDV market segments. The primary NLDV variation is an increase in use of CNG by some medium-duty vehicles in the Combustion scenario. Bio-based infrastructure-compatible fuel is blended with diesel and gasoline in different proportions across the three scenarios, such that the FCI differs by scenario for the resulting diesel and gasoline blends. Assumptions about blends that explain differences in Figure 3.20 among the low-carbon scenarios include: gasoline bio-based blends are used in greater volumes in the Portfolio scenario, have a relatively high FCI in the Electrification scenario, and are used in both higher volumes and with lower FCI in the Combustion scenario. Other characteristics are that ethanol does not play a major role in any of the three low-carbon scenarios (volumes are less than in BAU, shown as a red open square); CNG/LNG only plays a major role in the Combustion scenario; electricity has the same FCI in all scenarios (80% lower than the FCI in the BAU scenario (cf. NREL 2012); and hydrogen is very low-carbon only in the Electrification scenario. Each low-carbon scenario reaches the GHG goal by 2050, and does so via a different path, because of these variations in scenario input assumptions.

More specific effects underlying the fuel combinations in Figure 3.20 include the following:

Portfolio scenario (diamonds)

- A relatively high volume of gasoline blend compared to the other two scenarios results in less ethanol, hydrogen, or electricity use.
- The low carbon intensity of gasoline and diesel blends (due to greater use of bio-based infrastructure-compatible fuels) allows hydrogen and ethanol production methods to be higher carbon intensity than in the other two scenarios.

Combustion scenario (circles)

- Large volumes of CNG/LNG result in lower volumes of gasoline and ethanol, as well as very low hydrogen and electricity.
- Large volumes of relatively high carbon CNG/LNG fuels are countered by success with low-carbon diesel fuel blend components such as FT diesel.
- Technology improvement in low-carbon ethanol production is comparable to that of diesel biofuel blends.

Electrification scenario (triangles)

- Larger volumes of hydrogen and electricity reduce use of gasoline and ethanol blends.
- Very low-carbon intensity of hydrogen allows for less use of low-carbon, bio-based blend components in gasoline and diesel blends.

The different fuel mixes among scenarios result in a range of different fuel infrastructure expansion requirements between 2020 and 2050. In terms of fuel production, the Combustion scenario requires production of high volumes of very low-carbon diesel blend components, while the Electrification scenario requires high volumes of very low-carbon hydrogen. In terms of retail infrastructure, the Combustion scenario requires major expansion of CNG/LNG infrastructure, while the Electrification scenario requires major expansion of hydrogen and electric charging infrastructure. By comparison, the Portfolio scenario does not require retail infrastructure expansion on the same level as the Electrification or Combustion scenarios; it avoids a high degree of retail infrastructure expansion by relying upon the substitution of low-carbon gasoline from pyrolysis oil in the LDV market segment. This is highlighted by the total transportation fuel volumes in Figure 3.18 and the LDV miles by fuel type in Figure 3.13. One result of these fuel infrastructure expansion distinctions is that compared to the Portfolio scenario, the Electrification scenario reduces GHG emissions more in the LDV market segment, while the Combustion scenario reduces GHG emissions more in the NLDV market segments.

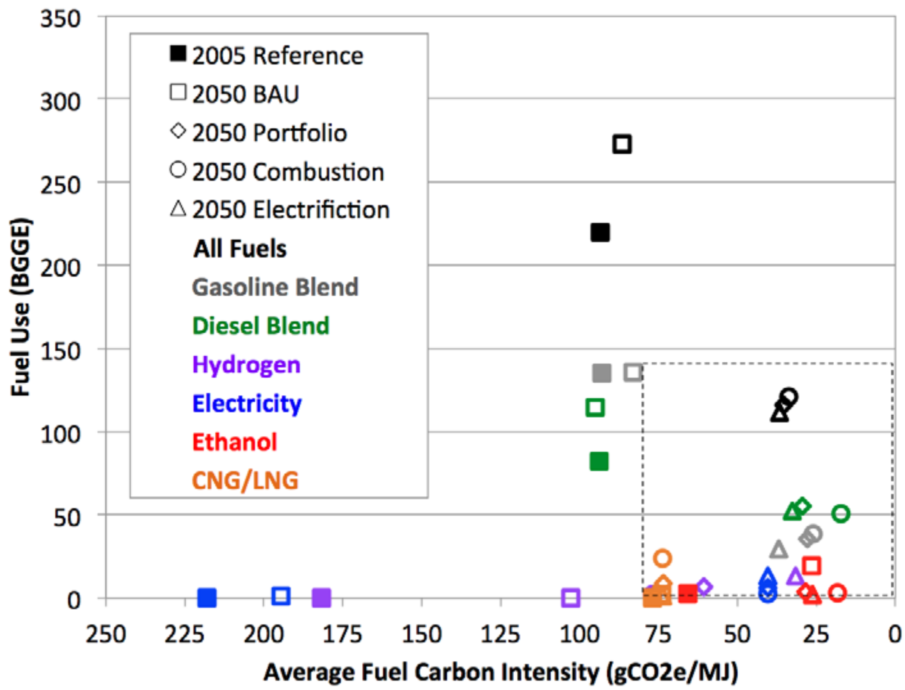


Figure 3.19. Fuel use and carbon intensity for all scenarios in 2050 and with 2005 reference

Detail of inset is shown in Figure 3.20

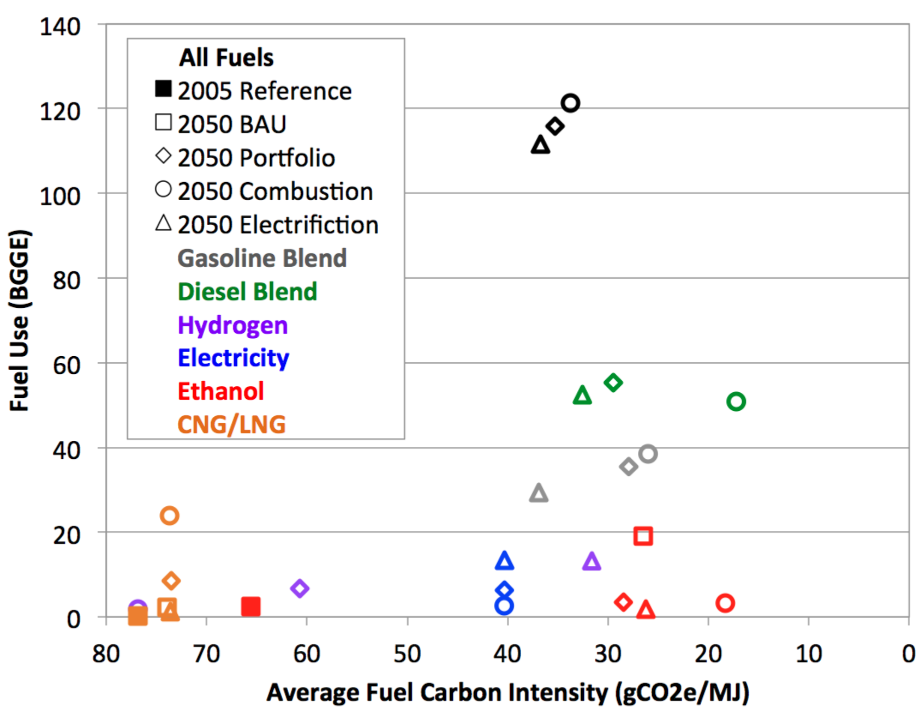


Figure 3.20. Summary of low-carbon scenario fuel use and carbon intensities in 2050

2005 reference only shown for CNG/LNG and ethanol; 2050 BAU does not shown for gasoline blend, diesel blend, hydrogen, or electricity.

Total GHG emissions from all transportation fuels are shown in Figure 3.21, Figure 3.22, and Figure 3.23. Compared to Figure 3.12b, these figures indicate the GHG emissions that remain after introducing sufficiently low FCI blends for each of the major fuels. However, this perspective on GHG reductions tends to obscure the relative contribution to GHG reductions by the different fuel and vehicle combinations. For example, the Portfolio and Electrification scenarios appear to be very similar on a GHG emission per fuel type basis, but the fuel volumes in Figure 3.18 show how they are distinct. Similarly, the large proportion of remaining GHG emissions from CNG/LNG in the Combustion scenario also contrasts with its smaller contribution to total fuel use in Figure 3.18. This aspect of the Combustion scenario is noteworthy in terms of identifying a limitation of this study. The option of blending lower carbon biogas was not examined, but it could prove to be an important alternative compensatory trend if sufficient volumes were possible. This production pathway (from either biogas sources or thermal production) would then leverage investments in natural gas delivery and retail equipment. Additional scenario trends are discussed in the evaluation results in Section 4.

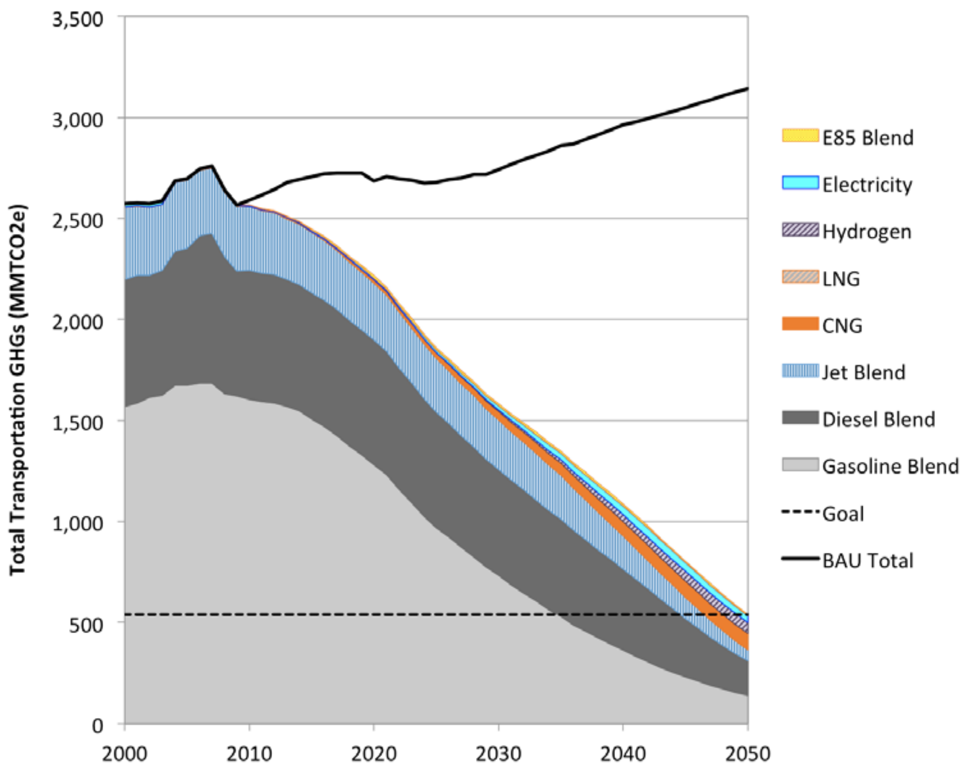


Figure 3.21. Total transportation GHG emissions in the Portfolio scenario

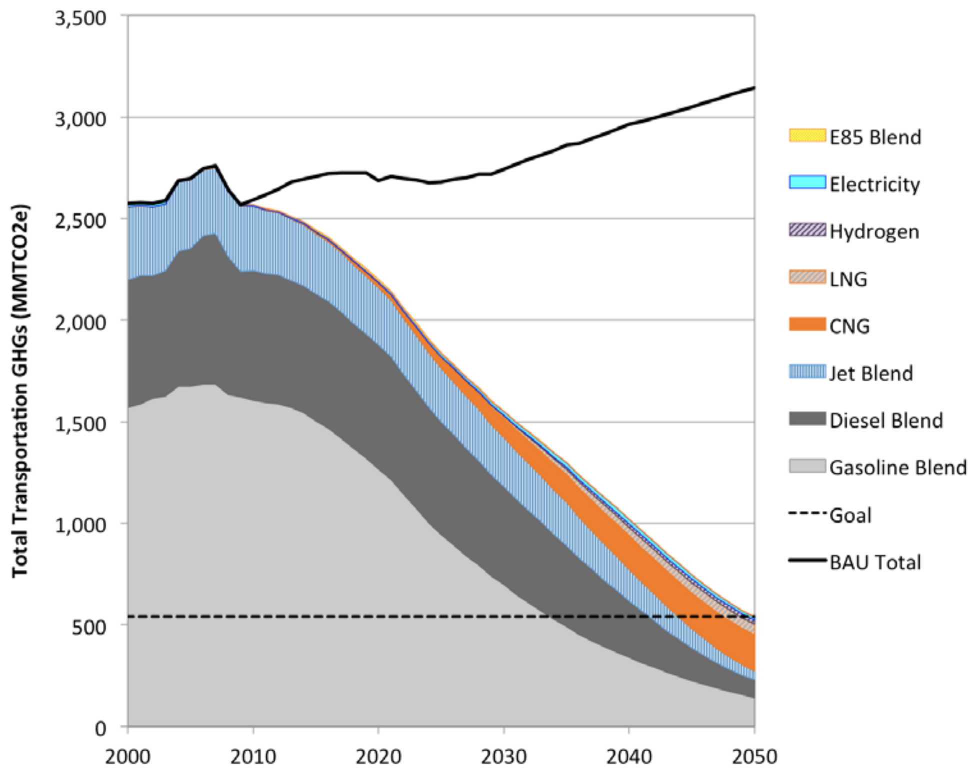


Figure 3.22. Total transportation GHG emissions in the Combustion scenario

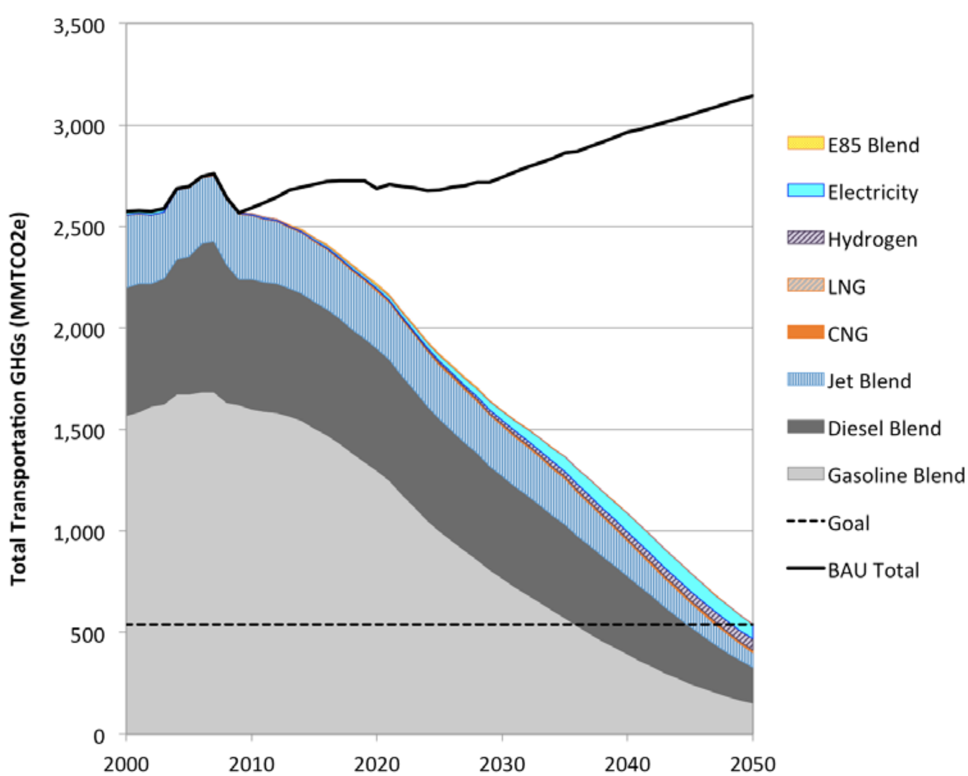


Figure 3.23. Total transportation GHG emissions in the Electrification scenario

4. Scenario Evaluation

The four sections below evaluate different characteristics of the three low-carbon scenarios in detail. Section 4.1 examines estimated fuel cost trends out to 2050, primarily based upon infrastructure capital and operating cost estimates and projections for feedstock costs. Fuel cost depends in part on infrastructure cost, and conversely, relative fuel cost influences the market competitiveness of a given fuel-vehicle system and its associated infrastructure. Because of the assumptions that increased efficiency and decreased demand would reduce fuel use, the bottom-up fuel cost estimates for the low-carbon scenarios show declining trends, which by 2050 reach costs less than the BAU scenario and even less than prices from the AEO Low Oil case (EIA 2011). Section 4.2 examines the degree to which each scenario relies upon different low-carbon energy resources, including biomass, natural gas, and curtailed renewable energy resources. With the selected assumptions about high end-use efficiency and high fuel yields, biomass resource use would not exceed levels identified as sustainable in the recently updated 2011 *Billion Ton Study* (BTS2) [U.S. Department of Energy (DOE) 2011], and incremental demand for natural gas or renewable electricity would be small relative to the size of those markets. Section 4.3 examines expansion trends for fuel production capacity, and Section 4.4 examines trends in retail infrastructure expansion. For both production facilities and retail outlets, the infrastructure expansion requirements in the low-carbon scenarios would be comparable to those anticipated in the BAU scenario.

4.1. Fuel Costs, Carbon Costs, and Market Considerations

Fuel costs for low-carbon fuels are extrapolated to 2050 based on fuel supply cost projections for the 2015–2030 timeframe. The cost trends are increasingly speculative beyond 2030, but they remain consistent relative to one another with respect to assumptions about infrastructure component unit costs and pathway conversion efficiencies underlying each scenario. Feedstock costs for biomass resources are based upon the BTS2 cost data for supply curves, resulting in increasing biomass costs at higher volumes. The rate of these cost increases is significant for the Combustion scenario due to the dominance of biofuels, and for the Electrification scenario because hydrogen production via biomass gasification becomes the dominant type of fuel production. Increasing costs are assumed for low-carbon electricity in each scenario, with a $0.03 per kilowatt-hour (kWh) premium added incrementally over time to the AEO 2011 reference case prices for residential and commercial electricity prices, resulting in a 20% increase in the cost of low-carbon electricity by 2050 [cf. National Renewable Energy Laboratory (NREL) 2012]. Comparisons are made to annual fuel costs in the BAU scenario for Reference, High Oil, and Low Oil prices. Comparisons to the Low Oil case prices are a low-end cost savings estimate, which would make deployment of low carbon fuels more challenging. The Low Oil case would also have higher BAU GHG emissions, but we did not examine an alternate overall GHG goal. Based upon these cost trends, fuel cost savings for each low-carbon scenario are estimated to range from $200–$1,000 billion per year (compared to the Low Oil price case or High Oil price case, respectively) by 2050 compared to BAU fuel prices. The high end of this range is the difference between the projected low-carbon scenario fuel costs and total fuel expenditures in the 2011 AEO High Oil price case, while the low end varies, depending on the scenario, from $200–$230 billion per year in comparison to total fuel prices in the 2011 AEO Low Oil price case. Including a cost of carbon of $80 per metric ton CO_2e ($MTCO_2e$), total savings approach a range of $350–$1,150 billion per year by 2050 compared to BAU (compared to Low Oil or High Oil prices, respectively).

The cost models used to support the present analysis do not explicitly account for market factors such as supply and demand equilibrium, demand elasticities, or substitution elasticities. Future fuel cost assumptions are based upon technical bottom-up estimates and include an assumed profit margin, but they are not comparable analytically to estimates of market prices that would be generated from an integrated economic model. This approach puts the scenarios into the category of bottom-up cost scenarios, which tend to underestimate actual prices realized in market outcomes (Wilson and Swisher 1993; Audus 2000;

Boehringer and Rutherford 2006). The results therefore represent relatively optimistic estimates of future technology performance, and they are compared to market prices reported from the AEO National Energy Modeling System model to provide context rather than to assert a claim of price equivalency. Furthermore, analytic methods aside, the fuel cost savings estimated here are contingent upon both achieving estimated technology cost targets and overcoming market barriers that would tend to dampen the adoption of low-carbon fuels and associated vehicles. How these market barriers might be overcome through policies or market mechanisms, and the probability of achieving technology cost targets, are both beyond the scope of this analysis. Finally, we only present fuel costs in this study, which include energy feedstock, production technology, and delivery infrastructure costs. A more complete analysis would incorporate vehicle costs, other vehicle ownership costs such as maintenance and insurance, as well as a broader range of external costs (Ogden et al. 2004; Sun et al. 2010; DOE 2012; Nguyen and Ward 2013).

Fuel cost assumptions on a per gasoline gallon equivalent basis are shown for each scenario in Figure 4.1 for the major fuel categories of gasoline, diesel, ethanol, hydrogen, and electricity. Variations in these fuel costs depend primarily upon biomass resource supply costs (from BTS2), which increase as greater quantities are required. Hydrogen in the Electrification scenario also relies upon biomass; therefore, the fuel cost increases according to the same biomass supply curves. Electricity prices for PHEVs, plug-in FCEVs, and BEVs are the same for all scenarios, with a \$0.08–\$0.27/kWh cost included in the fuel cost for electric recharging equipment, depending upon the utilization and type (cf. Melaina and Penev 2012), and a gradual ramp-up to an additional \$0.03/kWh premium for electricity from a low-carbon grid by 2050.

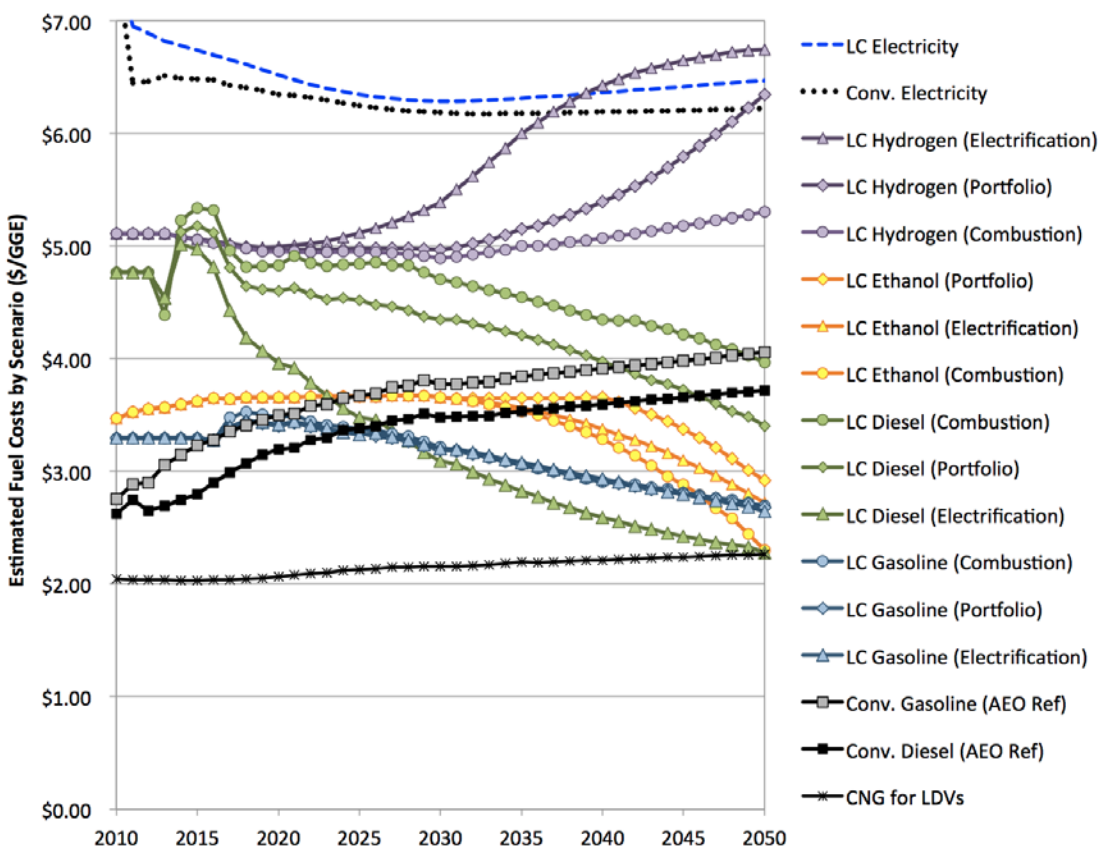


Figure 4.1. Comparison of scenario fuel costs, with reference to AEO Reference case, gasoline and diesel

Low-carbon fuels ("LC" in the legend) are derived partially or entirely from biomass. Cost variations between scenarios primarily depend upon biomass supply curves.

Total fuel costs for each scenario are shown in Figure 4.2. By 2050, total fuel costs for each scenario fall below BAU Low Oil case fuel prices. The convergence of costs for each scenario by 2050 occurs because conventional fuels are largely phased out by 2050, so the three different oil price levels from AEO no longer result in the same degree of divergence in the low-carbon scenarios as seen in the BAU cost trends. Costs also tend to converge across the low-carbon scenarios because of an assumed decline in the incremental cost of electric- and hydrogen-fueled pathways. This convergence of scenario cost estimates is an artifact of the sources and types of cost data used for the scenarios and should not be considered an estimation of decreasing uncertainty over time. Cost trends for the low-carbon scenarios are based upon point estimates, rather than ranges that take into account the uncertainties of various input assumptions.

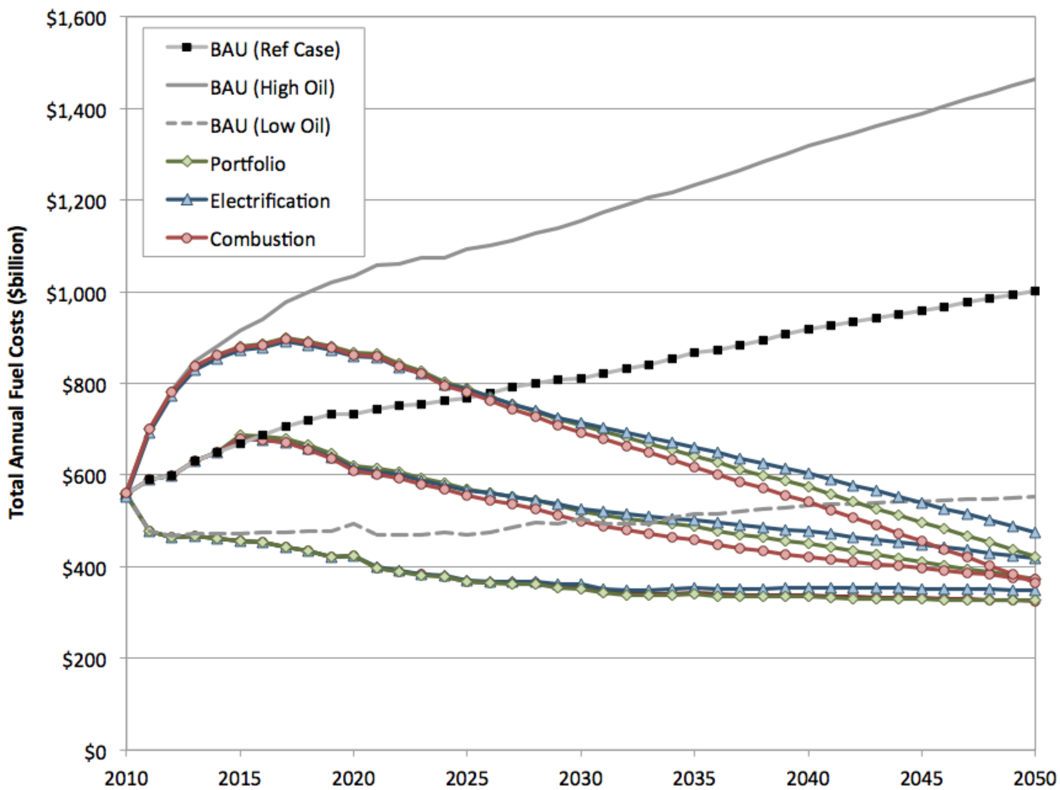


Figure 4.2. Total annual fuel costs for each low-carbon scenario, assuming conventional fuel prices from the AEO Reference, High Oil, and Low Oil cases

Total fuel savings are calculated as the difference between total fuel costs in the BAU scenario (i.e., 2011 AEO Low Oil case) and total fuel costs estimated in the low-carbon scenarios. These differences are shown in Figure 4.3, with annual fuel savings increasing to between $200 and $1,000 billion per year by 2040–2050, when compared to the Low Oil price case and High Oil price case, respectively. When a carbon price signal of $80/MTCO$_2$e is added, total fuel savings increase to $350–$1,150 billion per year by 2050. It is beyond the scope of this analysis to compare these long-term fuel savings to the additional near-term costs required to follow a low-carbon pathway (cf. National Research Council 2008; Greene et al. 2008). It is also beyond the scope to compare different scenarios with respect to metrics that take into account vehicle costs, such as the total cost of driving.

However, to place fuel costs into perspective, the additional annual consumer expenditures on vehicles if advanced LDVs cost $1,000–$5000 more per vehicle would be $22 to $108 billion each year.[3] This level of incremental annual total vehicle costs compares favorably to the annual fuel savings estimate. A market simulation or cost optimization framework applied to similar long-term cost estimate trends may provide additional insight into the various tradeoffs involved in market adoption of advanced LDVs and deployment of low-carbon fuels.

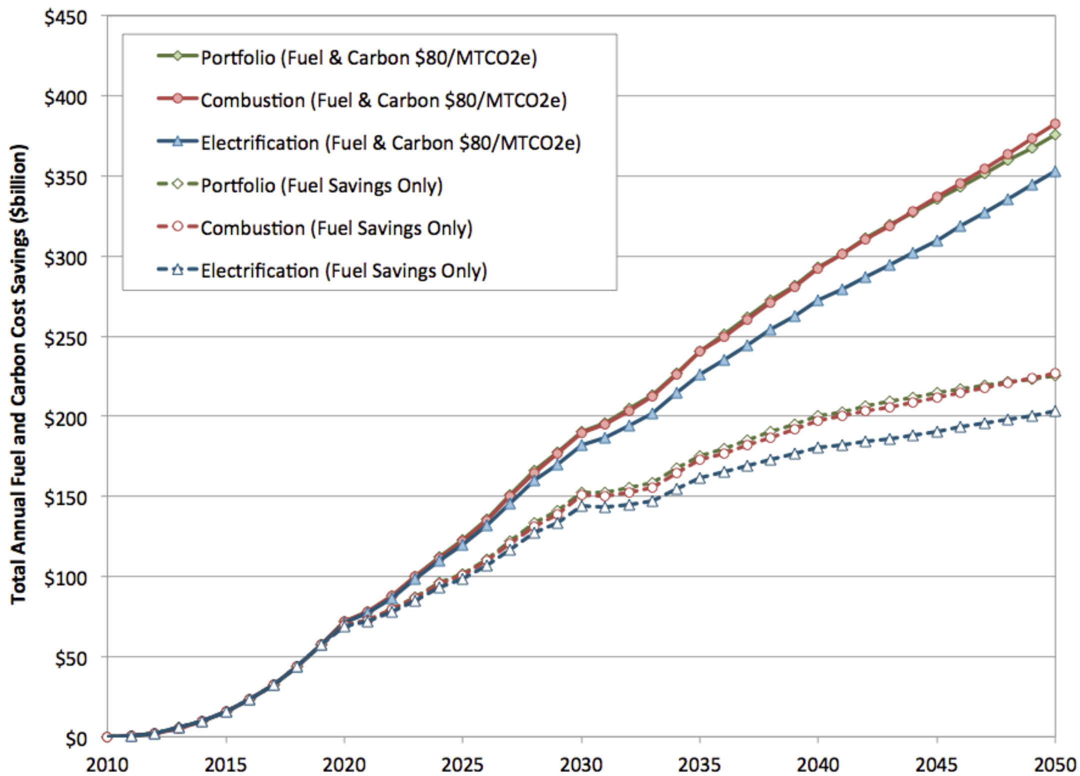


Figure 4.3. Annual fuel and cost of carbon savings at $80/MTCO$_2$e for each low-carbon scenario

Savings are calculated with reference to AEO 2011 Low Oil case prices for conventional petroleum fuels (gasoline, diesel, jet, and residual fuel). The annual increase in fuel savings slows between 2040 and 2050 while the cost of carbon savings continues to increase through 2050.

4.2. Resource Availability

The availability of low-carbon energy resources may prove to be a limiting factor in the technical and economic feasibility of reducing petroleum use and GHG emissions in transportation. In this section, resource availability is evaluated as a check across possible levels of utilization, rather than as a limiting constraint defining each scenario. A more integrated and market-based analysis approach would be needed to evaluate the tradeoff between investments in end-use efficiency and utilization of low-carbon energy resources. Three types of low-carbon resources are considered: biomass, natural gas, and grid-connected renewable electricity generation capacity. Utilization of biomass resources is addressed in

[3] This assumes approximately 21.7 million LDVs projected to be sold in 2050, with a hypothetical average cost premium range of $1,000–$5,000 per vehicle (for a mix of more efficient and alternative fuel drivetrains, compared to BAU), which would result in an additional $22 to $108 billion in expenditures. This would be paid annually and is in addition to what would have been the total expenses for conventional LDVs; it is the incremental cost for the increased market share of advanced LDVs.

direct connection to the scenarios while grid-connected renewables and natural gas are discussed in more general terms. Although nuclear power and fossil sources with carbon capture and storage (CCS) are also viable technical options for producing low-carbon fuels, these resources are not considered given the limited scope of the study.

4.2.1. Biomass Resources: Wastes and Residues

A variety of biomass feedstocks are currently used to generate electricity and produce heat and liquid transportation fuels. According to EIA, some 4.4 quads of biomass energy were produced in 2011, accounting for 48% of total renewable energy consumption and 4.5% of total U.S. primary energy consumption (EIA 2012a, Tables 2.1a and 10.1). In the United States today, the industrial sector accounts for 50% of total biomass energy consumption.[4] The residential and commercial sectors combined account for about 17% of total biomass energy consumption, and the electric power sector accounts for 8% of total biomass energy consumption. Transportation accounts for 31% of biomass energy consumption, 90% of which is due to ethanol use.

Expansion of the biomass resource base could include sources of biomass such as the following:

- *Forest biomass and wood waste resources*. These include forest residues (logging residues and thinnings) from integrated forest operations from timberland, other removal residue, thinnings from other forest land, unused primary and secondary mill processing residues, urban wood waste, and conventionally sourced wood.
- *Agricultural biomass and waste resources.* These include residues from major grain-producing crops, other crop residues, secondary agricultural processing residues, and waste or tertiary resources (e.g., manures, waste fats, and greases).
- *Energy crops*. These include perennial grasses, trees, and some annual crops (e.g., switchgrass), which are grown specifically to supply large volumes of uniform, consistent quality feedstocks for biofuel and biopower production.

In general, higher quantities of biomass are available at higher prices. Estimates of future biomass feedstock quantities are highly sensitive to feedstock price assumptions, and estimated price varies substantially by specific feedstock type and by region. A detailed assessment of the cost and availability of biomass resources for the production of transportation fuels would account for the regional distributions of different resource types. In the present evaluation, in contrast, resource use is estimated based upon general conversion ratios and national supply curves that were developed based on data from BTS2 (DOE 2011).

According to BTS2, assuming a conversion rate of 85 gallons per dry short ton (for cellulosic feedstock to biofuels), biomass from forest and agricultural biomass and wastes together has the potential to supply 25–38 billion gallons of biofuel in 2022 and 31–43 billion gallons in 2030. The addition of energy crops increases the total potential from biomass to 51–86 billion gallons of biofuel in 2022 and 65–111 billion gallons in 2030. The higher end of this range approaches the energy content of transportation fuel required for the low-carbon scenarios in the present analysis.

Land use change is a critical issue for future biomass supply. The BTS2 assumes that a portion of cropland and pasture land (60–80 million acres) could be shifted to produce energy crops without impacting food, feed, and export demands. This compares to 2.3 billion acres total land area in the United States, with 749 million acres of forest land and 455 million acres of agricultural land.

[4] Most industrial biomass energy use is from wood or wood-derived fuels (58%) or from losses and co-products from the production of fuel ethanol and biodiesel (32%) (EIA 2012a, Table 10.2b).

Competition for biomass for energy production is another critical issue. Use of biofuels and biopower could increase in the future, possibly resulting in increasing competition for biomass resources. Biomass is considered an allowable resource in most state renewable portfolio standard incentive programs (DSIRE 2012), and biofuels production quantities are mandated by the Energy Independence and Security Act of 2007 in the form of a renewable fuel standard. To date, there is no comprehensive policy covering both options.

The low-carbon scenarios presented here are only one example of how the transportation sector may use biomass resources to meet the 2050 GHG goal. An equilibrium model was developed and used to explore biomass utilization across multiple end-use sectors elsewhere in the TEF project (Ruth et al. 2013). The biomass use trends presented here represent assumptions based upon guidance from both Ruth et al. (2013) and supply curve data from BTS2, but they do not explicitly account for biomass use trends in other sectors. Table 4.1 summarizes rates of utilization, in million dry short tons (MDT) per year, for five types of biomass resources associated with the fuel pathway combinations used to reach the scenario FCI levels discussed above for each market segment by 2050. As discussed below, the resulting rates of utilization were apportioned so as not to incur excessive biomass supply costs for any one feedstock; relative use among biomass resource types is based upon time-series supply curve data from BTS2. When compared to supply curve data from BTS2, this distribution of demand across different biomass resource types corresponds to an average cost of approximately $50 per dry short ton by 2050.

The Combustion scenario requires the greatest amount of biomass resources, 833 MDT/year by 2050, while the Portfolio and Electrification scenarios would use 632 MDT/year and 724 MDT/year, respectively. These results are shown graphically in Figure 4.4 by both resource type and fuel type. A more detailed breakdown of fuel volumes and biomass resource use by specific fuel pathway is presented in Table 4.2, Table 4.3, and Table 4.4.

Table 4.1. Summary of Biomass Use by Type for All Scenarios in 2050

Scenario	Biomass Use by Type (MDT/year)					
	Corn	Wood Res.	SRWC	Stover	Switch	TOTAL
BAU	78.4	0.0	0.0	14.9	69.5	162.8
Portfolio	13.1	52.9	106.7	171.6	287.3	631.6
Combustion	1.0	62.9	146.6	264.1	358.4	833.1
Electrification	5.8	47.7	140.1	175.0	354.9	723.5

Note: Short rotation woody crops (SRWC) and switchgrass (Switch) are specific types of dedicated energy crops. Stover is an agricultural residue; wood residue (Wood Res.) is a forest residue.

These biomass resource utilization rates suggest that none of the low-carbon fuel scenarios would need to exceed the biomass resource supply base estimated by the BTS2. However, these utilization rates do not explicitly account for biomass use in the electricity sector; the market competition outcomes from Ruth et al. (2013) suggest that the transportation fuels market would dominate biomass resource consumption in a low-carbon future. A more detailed and multi-sector market analysis of similar low-carbon scenarios could estimate the fuel and electricity sector demands over time and explore implications of different biomass resource supply assumptions.

One question that arises from this conclusion is whether the Combustion scenario, which relies predominantly upon hybrid internal combustion engine vehicles in the LDV sector, would exceed biomass resource supply constraints if CNG LDVs were not assumed to attain a large market share. With the assumptions underlying the current set of low-carbon scenarios, it appears that even with the incremental increase in biomass resource use required to substitute for CNG vehicles, the total biomass resource used would still be less than one billion dry short tons. This scenario sensitivity result is shown in Figure 4.5 with the total biomass use of 876 MDT in the alternate “Without CNG” Combustion scenario, labeled as “wo CNG” in the figure and shown alongside usage for the other three scenarios. In this sensitivity run, it was assumed that an increase in biomass-based pyrolysis fuels compensates for the shortfall in GHG emission reductions resulting from a low market penetration of CNG LDVs.

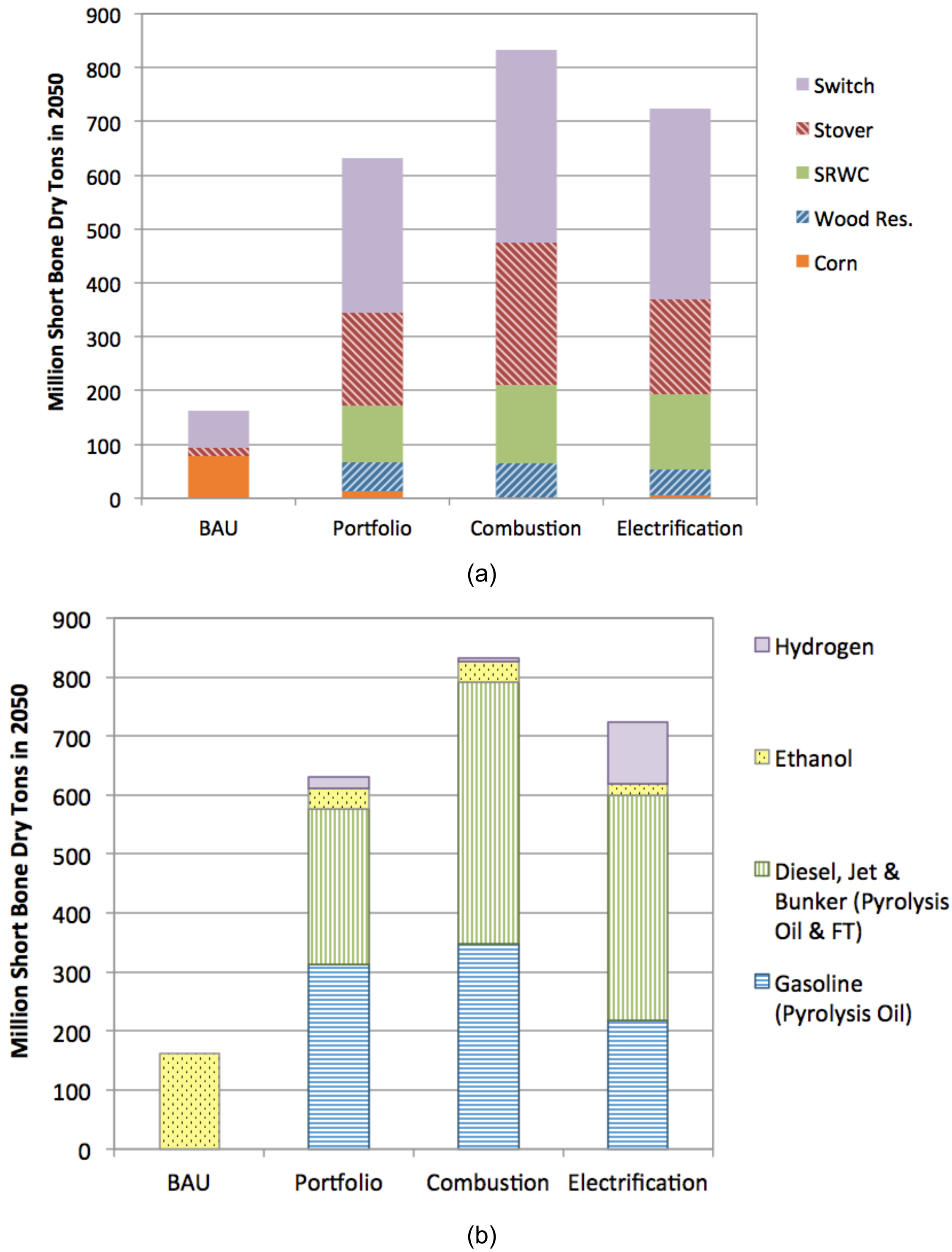


Figure 4.4. Summary of biomass resource use for all scenarios in 2050 by (a) resource type and (b) fuel type

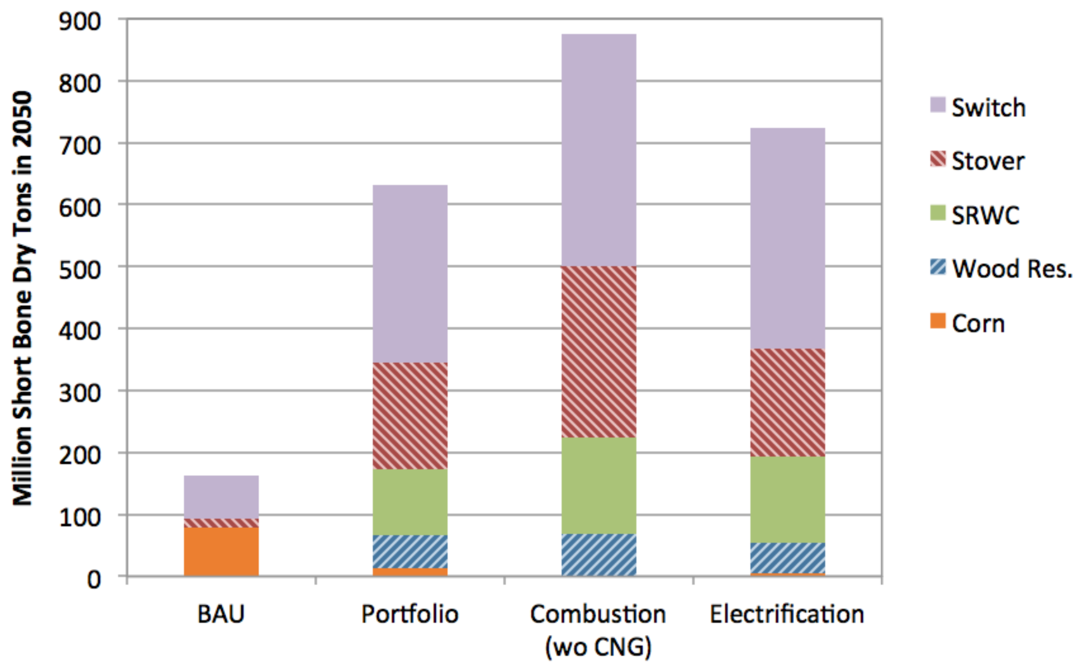


Figure 4.5. Summary of biomass resource use for scenarios in 2050

This assumes an alternate Combustion scenario with CNG LDVs achieving only 2% market share by 2050. This alternate scenario assumes that an increase in pyrolysis gasoline compensates for the reduction in CNG LDVs, resulting in higher utilization of biomass resources.

Table 4.2. Conventional and Pyrolysis Oil Gasoline and Biomass Use for Each Scenario in 2050

Scenario	units	GASOLINE						TOTAL
		Conventional		Pyrolysis Oil				
		Petrolm.	Oil Sands	Wood Res.	SRWC	Stover	Switch	
BAU	BGGEs	108.8	17.4	0.0	0.0	0.0	0.0	126.2
	MDT	-	-	0.0	0.0	0.0	0.0	0.0
Portfolio	BGGEs	3.4	0.8	2.8	5.5	10.2	12.8	35.5
	MDT	-	-	28.3	55.1	101.8	128.2	313.4
Combustion	BGGEs	2.9	0.8	2.0	6.4	11.2	15.1	38.5
	MDT	-	-	19.9	64.2	112.2	151.1	347.4
Electrification	BGGEs	6.8	0.6	1.5	3.9	7.2	9.3	29.4
	MDT	-	-	14.7	38.9	71.9	93.4	218.9
Biomass Use	gge/DT	-	-	100	100	100	100	-

Biomass Use indicates biomass conversion process yield in gallons gasoline equivalent (gge) per dry short ton, based on Ruth et al. (2013).

Table 4.3. Diesel Blend Sources and Biomass Use for Each Scenario in 2050

Scenario	units	DIESEL, JET & BUNKER												TOTAL
		Conv.	Biodiesel		Pyrolysis Oil				FT Diesel					
		Petrolm.	Soy	Algae	Wood Res.	SRWC	Stover	Switch	Wood Res.	SRWC	Stover	Switch		
BAU	BGGEs	114.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		114.7
	MDT	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
Portfolio	BGGEs	22.3	2.3	11.2	1.6	3.7	6.1	6.1	0.1	0.1	0.1	5.0		58.5
	MDT	-	21.0	100.5	15.9	37.1	60.9	61.2	1.2	1.1	1.4	84.5		384.8
Combustion	BGGEs	7.1	2.0	9.4	1.3	3.8	6.9	7.0	1.1	2.0	4.3	7.5		52.5
	MDT	-	18.1	84.7	12.9	37.8	69.4	70.3	21.0	33.8	73.4	126.3		547.8
Electrification	BGGEs	23.3	2.1	0.0	1.8	5.5	8.8	8.8	0.1	0.1	0.1	7.6		58.1
	MDT	-	19.0	0.2	17.8	54.8	87.9	87.9	1.3	1.1	1.2	128.4		399.7
Biomass Use	gge/DT	-	111	111	100	100	100	100	53	59	59	59		-

Biomass Use indicates biomass conversion process yield in gallons gasoline equivalent (gge) per dry short ton, based on Ruth et al. (2013).

Table 4.4. Ethanol in E85 and Hydrogen Sources and Biomass Use for Each Scenario in 2050

Scenario	units	Ethanol Gasoline Blend and E85						Hydrogen						
		Corn	Wood Res.	SRWC	Stover	Switch	TOTAL	Central Nat. Gas	Ave. Grid Electrls.	Wind Electrls.	Coal w CCS	Biomass w CCS	Biomass wo CCS	TOTAL
BAU	BGGEs	9.2	0.0	0.0	1.5	6.8	17.5	0.1	0.0	0.0	0.0	0.0	0.0	0.1
	MDT	78.4	0.0	0.0	14.9	69.5	162.8	-	-	-	-	0.0	0.0	0.0
Portfolio	BGGEs	1.54	0.5	0.5	0.5	0.5	3.7	3.7	0.0	1.4	0.0	0.0	1.6	6.6
	MDT	13.06	5.6	5.6	5.6	5.6	35.3	-	-	-	-	0.0	19.5	19.5
Combustion	BGGEs	0.12	0.8	0.8	0.8	0.8	3.4	1.5	0.0	0.0	0.0	0.0	0.5	2.0
	MDT	1.00	8.5	8.5	8.5	8.5	34.9	-	-	-	-	0.0	5.7	5.7
Electrification	BGGEs	0.7	0.4	0.4	0.4	0.4	2.1	1.4	0.0	3.3	0.0	0.0	8.6	13.3
	MDT	5.8	3.6	3.6	3.6	3.6	20.1	-	-	-	-	0.0	103.9	104.0
Biomass Use	gge/DT	118	98	98	98	98	-	-	-	-	-	83	83	-

4.2.2. Grid-Connected Low-Carbon Electricity

A significant quantity of low-carbon electricity from renewable sources, nuclear sources, or fossil sources with CCS would be necessary to reduce GHG emissions in the electricity sector. A variety of studies explore how different combinations of low-carbon electric-sector generation technologies might be used, and different timeframes, targets, assumptions, and analytic methods lead to a diversity of market share estimates for each technology. This analysis does not assume a particular technology mix that provides low-carbon electricity, but assumes an electric-sector GHG emissions level that could not be reached by fossil fuels (coal or natural gas) without CCS. Analysis of high-penetration renewable electricity is briefly discussed here to examine the feasibility of that pathway making a significant contribution to the low-carbon scenarios.

A recent study on high penetration of renewable electricity, the *Renewable Electricity Futures* study (REF), explores implications of integrating renewable electricity at a range of levels up to 90% of generation by 2050 (NREL 2012). The report finds that high penetration of renewable electricity is feasible with current generation technologies, and that a variety of measures can be used to increase the flexibility of the electric system to maintain supply–demand balance at high renewable penetration. One aspect of system flexibility is the ability to control the timing of certain loads. In considering the impact of transportation electricity demand on a renewables-based low-carbon electric grid, both the total transportation demand and the ability to control the timing of that demand are important.

Considering total amounts of generation, recent studies show that if PEVs displaced half of all vehicles on the road, they would require only an 8% increase in electricity generation (4% increase in capacity) (Liu et al. 2011). The REF study assumed 40% of personal vehicle stock was electric or PHEVs by 2050, resulting in transportation electricity load from PEVs of about 350 terawatt hours (TWh), or approximately 9% of the total estimated electricity demand of 3,900 TWh (NREL 2012).

Table 4.5 indicates the amount of electricity used by PEVs in each scenario in this analysis by 2050, as well as the total amount of electricity that would be needed if all hydrogen for FCEVs was produced via electrolysis. The Portfolio and Electrification scenarios indicate the highest levels of electricity use, between 300 and 600 TWh of electricity for either PEVs or FCEVs, sum to a theoretical maximum ranging from 600 to 1,100 TWh if all hydrogen were produced from electricity. Hydrogen can be produced from other low-carbon energy resources, so the FCEV TWh numbers reflect a maximum electricity requirement for each scenario.

Table 4.5. Electricity Use by PEVs and for Hydrogen Production for FCEVs in 2050

Scenario	units	Electricity for PEVs	Electricity needed to produce all hydrogen for FCEVs	Total (Max.)
BAU	TWh	46.8	2.1	49
Portfolio	TWh	292.9	259.8	553
Combustion	TWh	100.5	76.5	177
Electrification	TWh	488.9	519.8	1,009

Electrolysis conversion efficiency is assumed to be 42.3 kWh electricity per kilogram of hydrogen produced.

Some of the electricity used for PEVs and hydrogen production could be optimally timed to match inexpensive generation opportunities. The REF study assumed that by 2050, 45% of the total vehicle energy demand of 350 TWh was "dynamic" or under managed control such that its timing could be optimized on a daily basis, while the remaining 55% was a "fixed" load that could not be timed optimally. In Figure 4.6, the total annual energy demand for PEVs from the REF study is shown for both fixed and dynamic PEV loads. In 2030, the fixed demand is approximately 50 TWh, accounting for approximately 80% of the total PEV load. By 2050, the total load grows to 350 TWh, and the fixed portion is approximately 180 TWh, or 55% of the total load (NREL 2012).

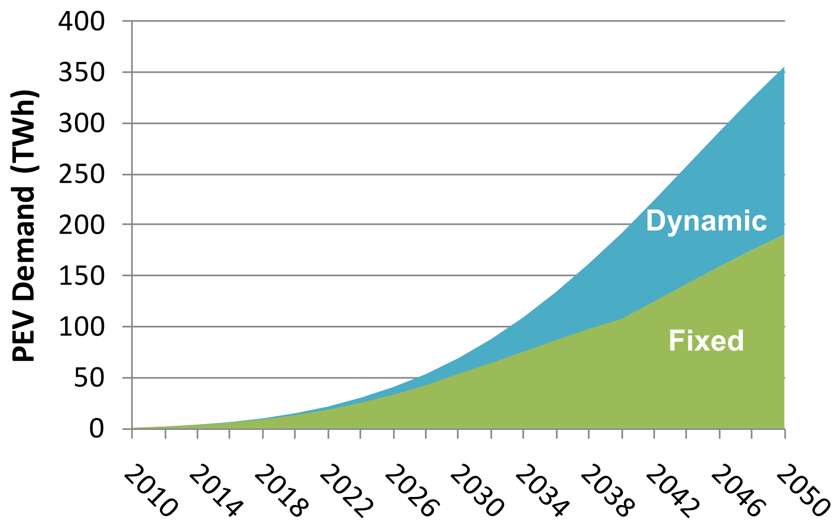


Figure 4.6. Projected fixed and dynamic annual PEV electricity demand from the REF study

(Source: NREL 2012)

Dynamic PEV load grows as a percentage of total PEV load. The maximum generation needed under the Electrification scenario (including both PEVs and FCEVs running on renewable electrolytic hydrogen) is almost three times the PEV load that was assumed in the REF study. A significant portion of that load would likely be controllable for optimal timing, and therefore is unlikely to require additional generation capacity. The fixed portion of that load is more likely to require additional generation capacity, and could also face bottlenecks in delivering energy to the vehicles and in highly populated or congested areas. The present scenario analysis did not develop a distinction between fixed and dynamic PEV load as was done in the REF study (NREL 2012). However, as a point of reference, if half of the PEV maximum load in Table 4.5 were fixed load, some 245–500 TWh, this would be approximately 5%–10% of the projected net electricity use in 2050, based on extension to 2050 of AEO 2011 projections.

4.2.3. Natural Gas Use for LDVs

CNG vehicles play a major role in the Combustion scenario, reducing GHG emissions in the early decades of the scenario and maintaining lower fuel costs than other scenarios through to 2050. The majority of natural gas demand is for hybrid electric–natural gas LDVs, though some M/HDVs also run on LNG. One measure of the impact of this increased demand for natural gas is a comparison to the BAU demand for natural gas in transportation and other sectors. Figure 4.7 compares the LDV demand for CNG to the demand for natural gas in all sectors from the AEO 2011 Reference case (EIA 2011). AEO demand trends are extrapolated linearly beyond 2035. The very small transportation demand in AEO 2011 is indicated by an arrow, and falls between Electric Power and Industrial use in the figure. Natural gas demand for vehicles in the Combustion scenario, at about 2.2 quads by 2050, is overlaid at the bottom of the figure and indicated by an arrow. This additional demand is about half of the total demand in the residential sector and about 8% of the overall projected BAU natural gas demand by 2050. From this simple comparison we conclude that the increased demand is large enough that it could increase natural gas price above the Reference case prices; the CNG prices in the Combustion scenario therefore underestimate prices that would be expected using a market-based modeling approach.

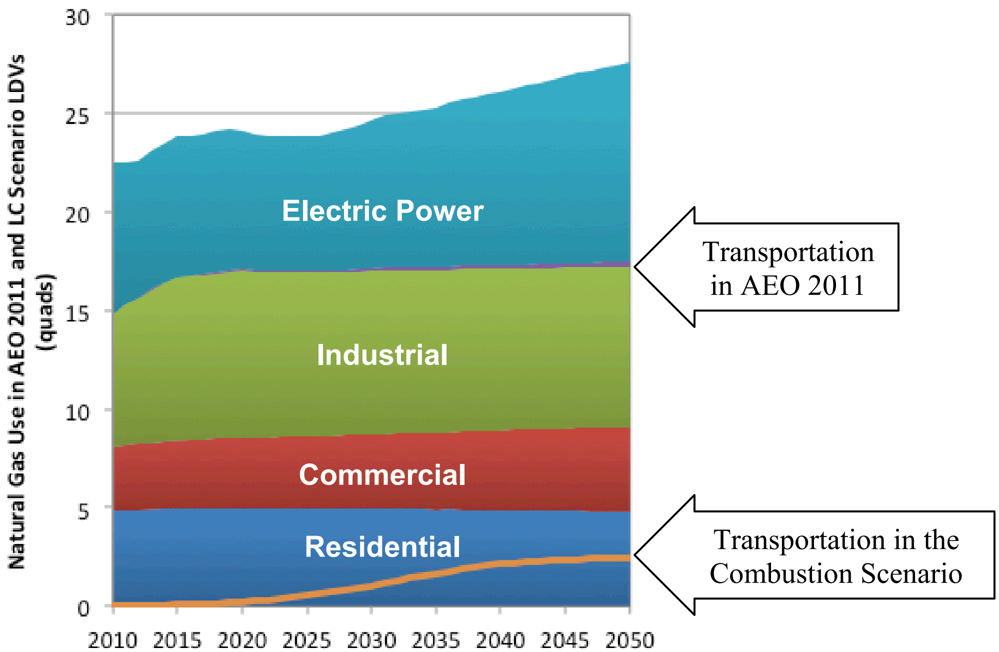


Figure 4.7. CNG use by vehicles in the Combustion scenario compared to natural gas across all sectors in the 2011 AEO Reference case; includes extrapolation of AEO beyond 2035

4.3. Production Capacity Expansion

Addition of new low-carbon fuel production capacity is key to the expansion of the fuel supply infrastructure in the low-carbon scenarios. This section reviews trends in fuel production capacity for each low-carbon scenario with reference to fossil fuel production (petroleum refining) capacity trends in the BAU scenario. The trends associated with annual changes in fuel demand serve as a proxy for fuel production capacity expansion trends; actual production capacity expansion would occur with some degree of mismatch to future demand. Detailed consideration of production capacity quantities, construction timing, and costs for all of the components of fuel production systems is beyond the scope of this study, as is consideration of optimal capacity expansion pathways. The fuel volume trends reported in Section 3.2 provide insight into general production capacity trends: BAU petroleum fuel demand would increase from about 200 BGGE/yr in 2010 to about 250 BGGE/yr in 2050, while total fuel use in the low-carbon scenarios would range from 110 to 120 BGGE/yr in 2050. The general fuel production trend in the low-carbon scenarios is that conventional petroleum fuel production declines by approximately 80%, while low-carbon fuel production capacity increases. The low-carbon fuel production capacity increase of 80 to 90 BGGE/yr is about twice as large as the expansion of 40 BGGE expected for petroleum fuels in the BAU scenario.

The three-year moving average of the annual change in demand for fossil, low-carbon, and pyrolysis fuels is indicated in Figure 4.8. Three-year average values are shown to emphasize longer-term trends rather than yearly variation. For the BAU scenario, black squares are the change in demand for conventional fossil fuels and grey squares indicate changes in demand for low-carbon fuels. The BAU scenario, from the AEO 2011 Reference case (EIA 2011), shows fluctuations between 2010 and 2035, and includes a few years of demand reductions (negative values), and then relatively stable increases on the order of 1.6 BGGE/yr for the extrapolations beyond the AEO's 2035 results to 2050. Two sets of values are shown for changes in demand for each of the Low Carbon scenarios. The All Low-Carbon Fuels values indicate changes in demand for all non-petroleum fuels, and the Pyro-Oil Fuels demand trends indicate biomass-based inputs that may be refined, at least in part, at existing petroleum refining facilities. After 2035, the demand for pyro-oil fuels is comparable to or less than the demand for petroleum fuels in the BAU scenario. Fuel demand changes are generally less for the Electrification and Portfolio scenarios than for the Combustion scenario.

The distinction between pyrolysis oil fuels and other low-carbon fuel types is relevant because the existing petroleum refining and distribution infrastructure could be used to bring infrastructure-compatible fuels to market (see Figure 2.1), so the incremental output changes from pyrolysis oil fuels would leverage existing infrastructure. Describing the process design changes involved in using existing infrastructure in this manner is beyond the scope of this report. Figure 4.9 indicates yearly output fluctuation trends for infrastructure-compatible and conventional petroleum fuels, and shows that in all three low-carbon scenarios the decline in output of conventional petroleum fuels, about 4–5 BGGE/yr after 2030, is greater than the annual increase in infrastructure-compatible pyrolysis oil fuels, which is about 1–2 BGGE/year after 2030. These trends suggest that it is possible that sufficient excess refinery capacity could be available for processing biomass pyrolysis oil feedstock. While additional costs may be required to modify refinery capacity or build new capacity in different locations, significant cost savings might be achievable compared to building new refinery capacity for all new pyrolysis oil fuel products. A detailed, process-level cost analysis would be needed to better understand the potential.

Summing these annual changes provides an estimate of long-term fuel production capacity changes over time. For example, Figure 4.10 shows the result of summing annual fuel supply fluctuations between 2010 and 2050 for each scenario, resulting in a net change in fuel supply capacity. Conventional petroleum supply capacity increases by 46 BGGE and low-carbon fuel supply capacity increases by 17 BGGE in the BAU scenario. In contrast, conventional petroleum supply capacity declines by more than 120 BGGE in each low-carbon scenario, pyrolysis oil production capacity increases by 49 to 56 BGGE, and other low-carbon fuel supply capacity increases by 30 to 52 BGGE.

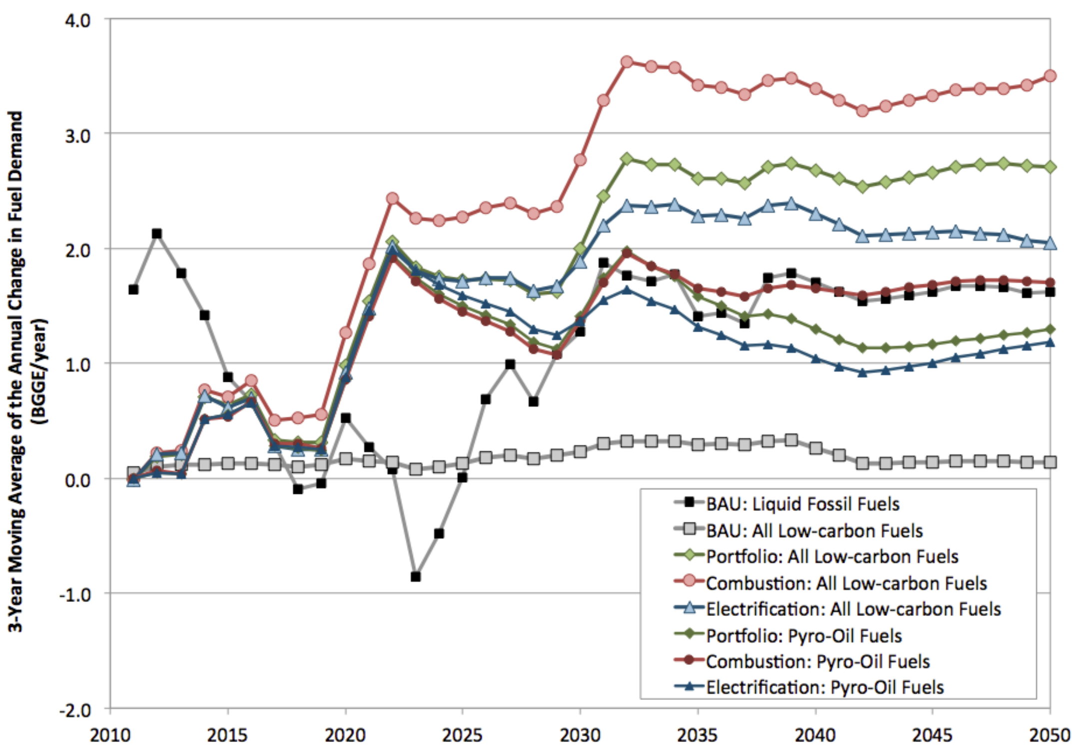


Figure 4.8. Three-year moving average of annual changes in fuel demand, including liquid fossil fuels (BAU), pyrolysis oil fuels, and all low-carbon fuels (BGGE/year)

Liquid fossil fuels are shown for the BAU scenario, and low-carbon fuels are shown in the other three scenarios.

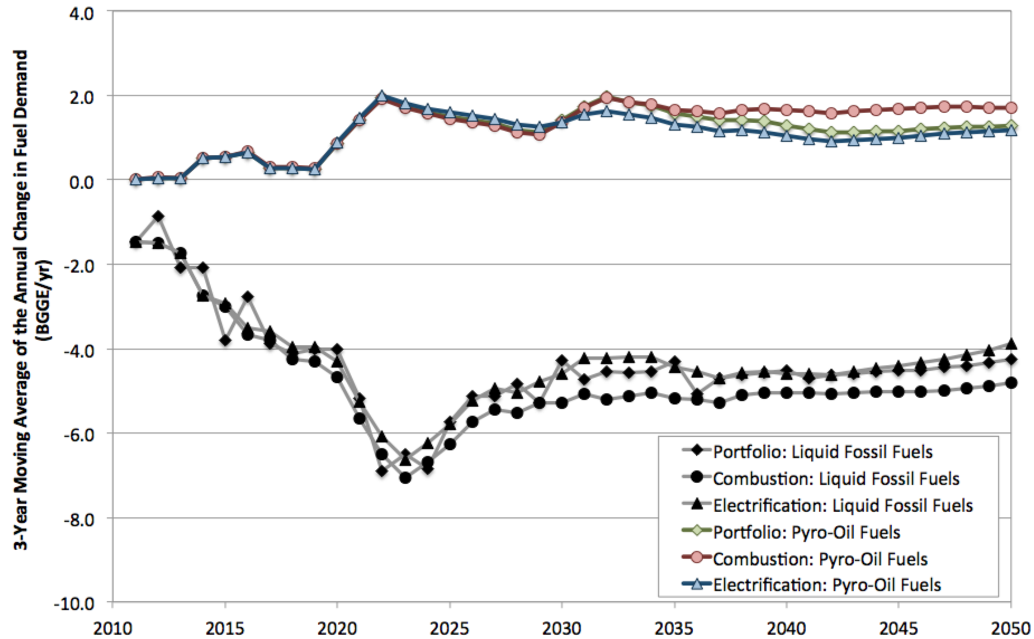


Figure 4.9. Three-year moving average of annual changes in fossil fuel and pyrolysis oil fuel demand (BGGE/yr)

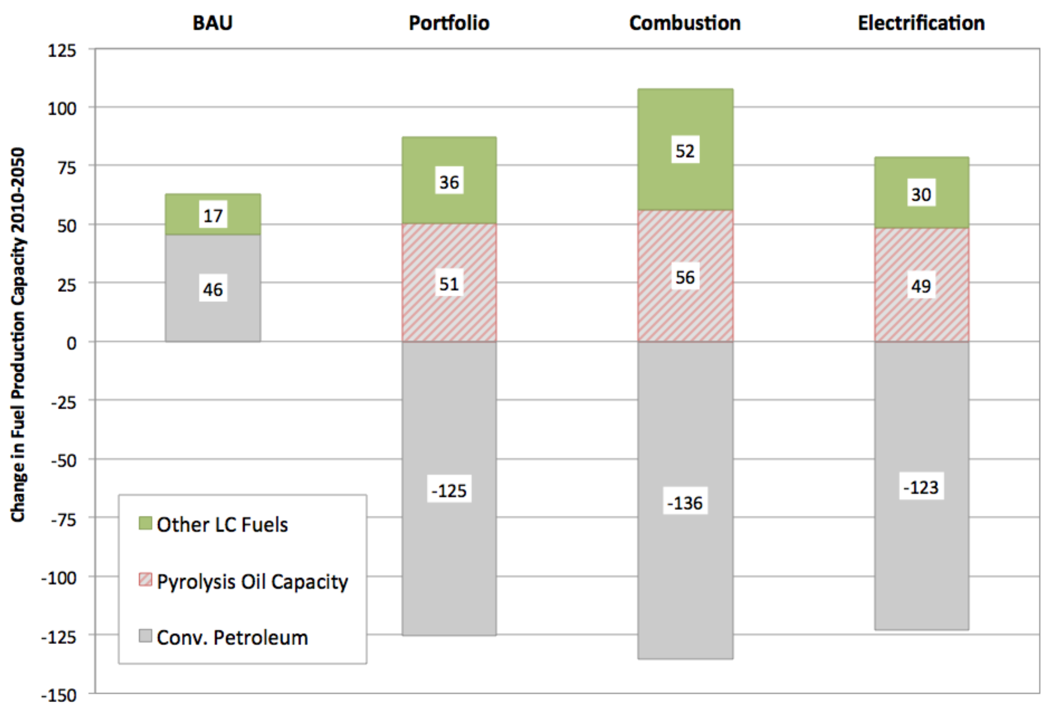
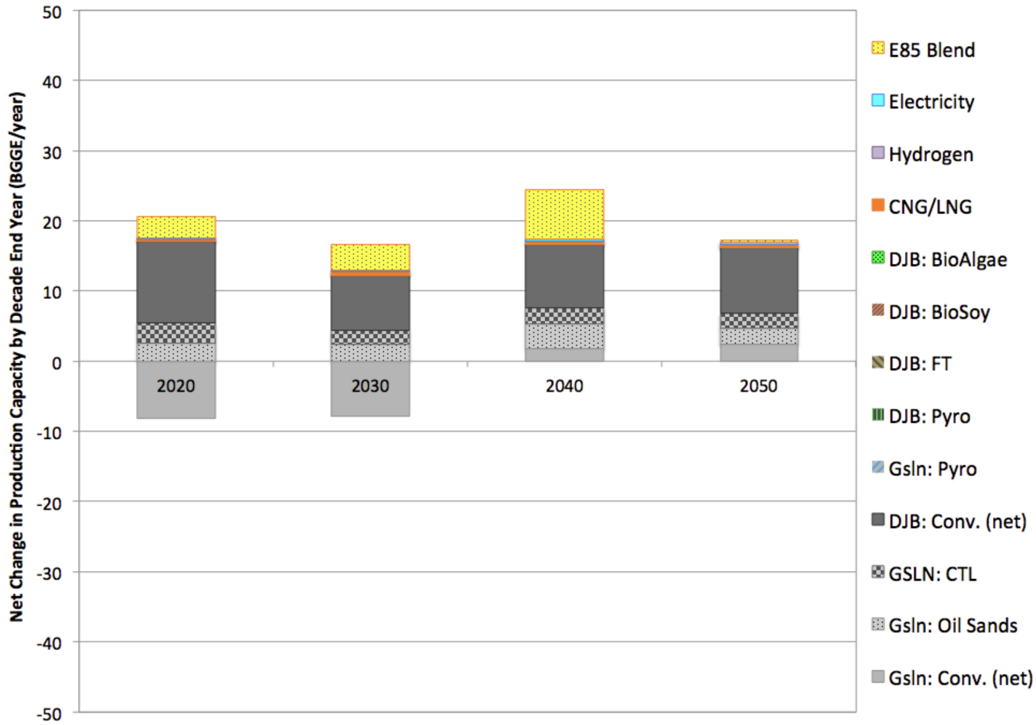


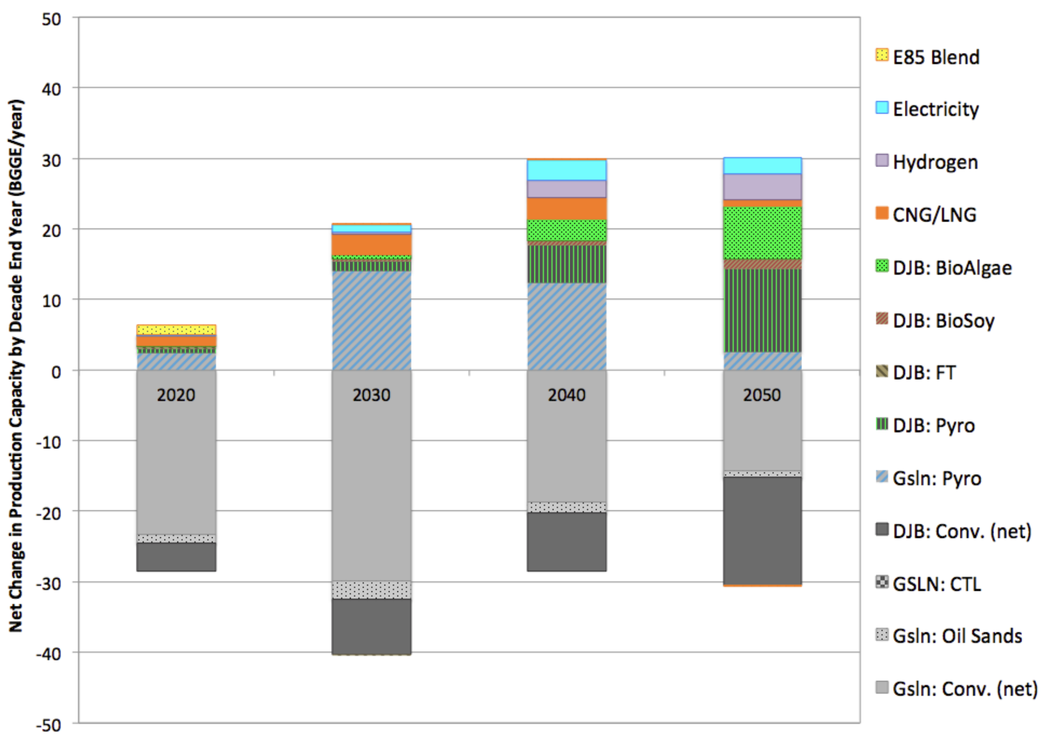
Figure 4.10. Net change in fuel production capacity from 2010 to 2050

Retired capacity (negative regions) includes conventional and unconventional (tar sands and coal-to-liquids) fossil fuel production. Pyrolysis oil capacity is assumed to be conventional gasoline and diesel capacity that has been converted to use biomass pyrolysis oil rather than crude oil. New capacity includes net new conventional, unconventional, and low-carbon fuel production. Note that for each low-carbon scenario, new capacity is less than that in the BAU scenario and the sum of new and converted capacity is less than retired capacity.

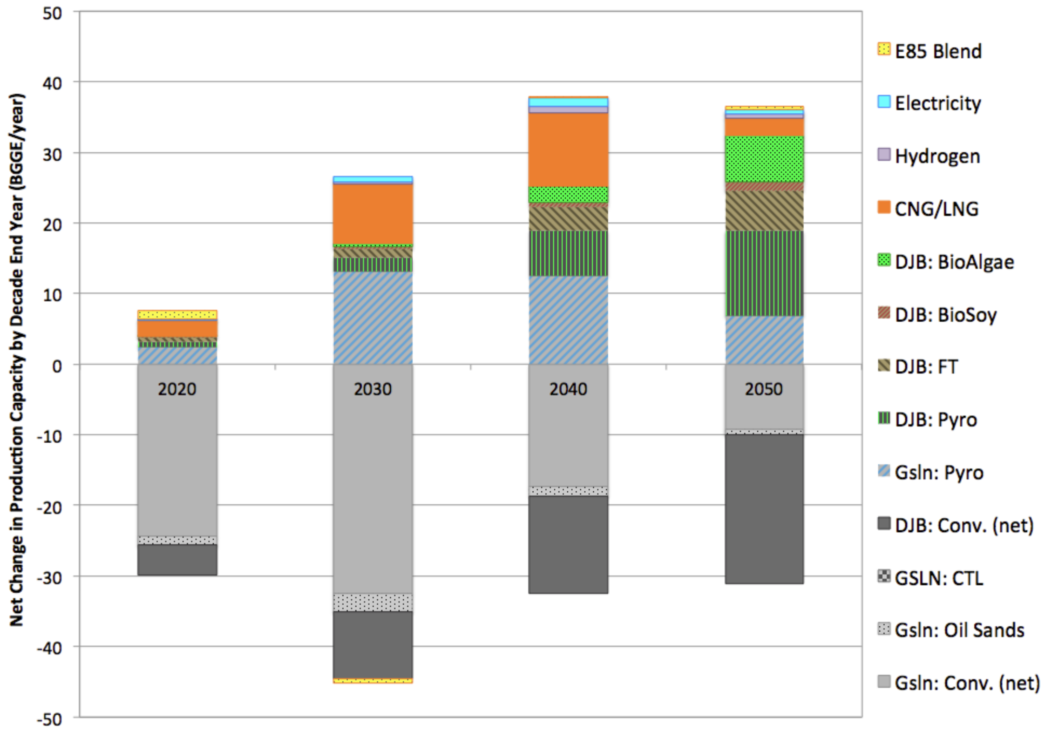
Figure 4.10 illustrates that conventional petroleum refining capacity would be idled at a more rapid rate than infrastructure-compatible fuel production capacity would grow, and that production capacity for other low-carbon fuels is less than the new total capacity expected in the BAU scenario. While it is possible that the United States would utilize some of its excess refinery capacity to increase exports of refined products, these products would not be used to meet U.S. demand and so are not considered here. These capacities are expressed in BGGE of output, while a measure of thermal feedstock input would be different, especially for the Electrification scenario that relies on hydrogen and electricity. More details on the types of fuel supply capacity changes occurring by decade within each scenario are provided in Figure 4.11. Values underlying these figures are summarized in Table 4.6. The general trend in decadal expansion of low-carbon fuel production capacity for the low-carbon scenarios is an addition of less than 10 BGGE from 2010 to 2020, just over 20 BGGE from 2020 to 2030, and about 30–35 BGGE from 2030 to 2040 and from 2040 to 2050.



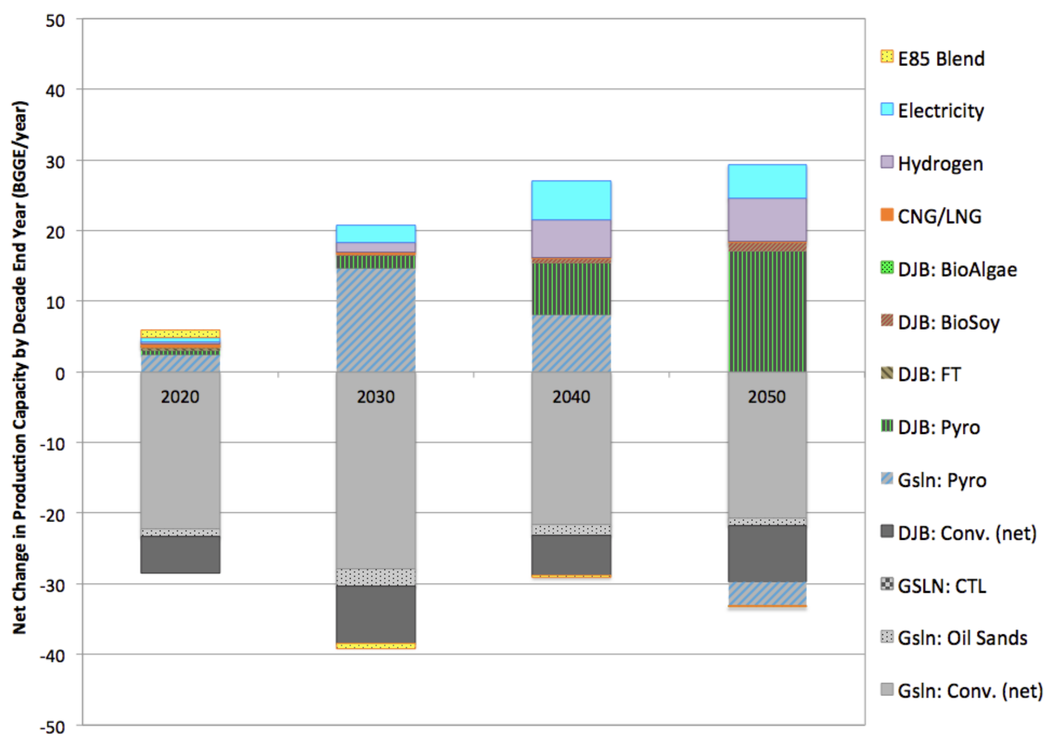
(a) BAU Scenario



(b) Portfolio Scenario



(c) Combustion Scenario



(d) Electrification Scenario

Figure 4.11. Change in fuel production capacity by decade end year for each scenario

CNG = compressed natural gas; CTL= coal to liquids; DJB = diesel or jet from biomass; FT = Fischer-Tropsch; GSLN = gasoline; LNG = liquefied natural gas

Table 4.6. Net Change in Fuel Production Capacity by end of Decade for Each Scenario

(BGGE/yr production capacity)

Business as Usual Scenario

Decade	Gasoline Capacity				Diesel - Jet - Bunker					CNG/LNG	Hydrogen	Electricity	E85 Blend
End	Conv. (net)	Oil Sands	CTL	Pyro	Conv. (net)	FT	Bio-Soy	Pyro	Bio-Algae				
2020	-8.2	2.5	3.0	0.0	11.5	0.0	0.0	0.0	0.0	0.35	0.01	0.14	3.09
2030	-7.8	2.3	2.1	0.0	7.7	0.0	0.0	0.0	0.0	0.61	0.02	0.28	3.53
2040	1.8	3.5	2.3	0.0	9.0	0.0	0.0	0.0	0.0	0.51	0.01	0.33	6.99
2050	2.5	2.2	2.1	0.0	9.3	0.0	0.0	0.0	0.0	0.51	0.01	0.35	0.24

Portfolio Scenario

Decade	Gasoline Capacity				Diesel - Jet - Bunker					CNG/LNG	Hydrogen	Electricity	E85 Blend
End	Conv. (net)	Oil Sands	CTL	Pyro	Conv. (net)	FT	Bio-Soy	Pyro	Bio-Algae				
2020	-23.3	-1.2	0.0	2.4	-4.0	0.3	0.1	0.6	0.1	1.32	0.04	0.18	1.36
2030	-29.9	-2.5	0.0	14.0	-7.9	0.0	0.2	1.5	0.6	2.87	0.42	0.96	0.21
2040	-18.8	-1.4	0.0	12.4	-8.3	0.0	0.6	5.4	3.0	2.96	2.57	2.81	0.25
2050	-14.3	-0.9	0.0	2.6	-15.3	0.0	1.4	11.8	7.4	1.01	3.62	2.26	-0.08

Combustion Scenario

Decade	Gasoline Capacity				Diesel - Jet - Bunker					CNG/LNG	Hydrogen	Electricity	E85 Blend
End	Conv. (net)	Oil Sands	CTL	Pyro	Conv. (net)	FT	Bio-Soy	Pyro	Bio-Algae				
2020	-24.4	-1.2	0.0	2.4	-4.2	0.7	0.1	0.7	0.1	2.20	0.04	0.17	1.14
2030	-32.5	-2.6	0.0	13.1	-9.6	1.3	0.2	2.0	0.5	8.47	0.32	0.70	-0.51
2040	-17.4	-1.3	0.0	12.5	-13.9	3.4	0.6	6.5	2.2	10.49	0.96	1.17	0.03
2050	-9.2	-0.7	0.0	6.8	-21.1	5.7	1.2	12.1	6.6	2.57	0.63	0.53	0.42

Electrification Scenario

Decade	Gasoline Capacity				Diesel - Jet - Bunker					CNG/LNG	Hydrogen	Electricity	E85 Blend
End	Conv. (net)	Oil Sands	CTL	Pyro	Conv. (net)	FT	Bio-Soy	Pyro	Bio-Algae				
2020	-22.2	-1.1	0.0	2.5	-5.2	0.3	0.1	0.6	0.0	0.53	0.31	0.49	1.06
2030	-27.9	-2.4	0.0	14.7	-8.2	0.0	0.2	1.8	0.0	0.21	1.42	2.39	-0.64
2040	-21.6	-1.5	0.0	8.1	-5.7	0.0	0.6	7.3	0.0	0.13	5.37	5.57	-0.27
2050	-20.7	-1.0	0.0	-3.4	-8.0	0.0	1.2	17.1	0.0	0.12	6.20	4.78	-0.07

CNG = compressed natural gas; CTL = coal to liquid; FT = Fischer-Tropsch; LNG = liquid natural gas; Pyro = pyrolysis oil

4.4. Retail Infrastructure Expansion

Section 2.1 introduced the current status of retail fueling infrastructure and the fueling infrastructure needs of alternative fuels. This section estimates the geographic characteristics and costs of retail fueling infrastructure expansion to support the low-carbon scenarios. To do so, we first discuss what metrics can be used to determine if the density of retail fueling infrastructure is sufficient to satisfy consumer needs for station availability. Second, we present estimates of costs per unit for EVSE, liquid, and gaseous fuel supply equipment. Third, we estimate the total costs of expanding retail fueling infrastructure in the BAU, Portfolio, Combustion, and Electrification scenarios and discuss differences in retail infrastructure geographic coverage across the scenarios. As is the case for the upstream fuel supply cost estimates, this representation of retail infrastructure costs is simplified, assumes a relatively high level of technology development, and does not explicitly account for market dynamics or stakeholder decisions.

Retail infrastructure serving the LDV market would need to expand significantly to provide new low-carbon fuels to a growing U.S. population. Much of the growth in population is expected to occur in urban areas, and the spatial distribution of that growth has important implications for infrastructure requirements. Cities with lower population densities require a more diffuse retail infrastructure, essentially resulting in fewer stations per square mile and smaller stations (on average), while more densely populated cities can be served with a higher density of larger stations (on average) (Melaina and Bremson 2008). Geographic coverage is more critical for LDVs than for NLDVs because LDV drivers refuel at a larger number of outlets that tend to be in prime retail locations and distributed across urban areas. Alternative fuel vehicles that cannot use gasoline or diesel, such as CNG vehicles, FCEVs, or BEVs, require station availability across large geographic areas to provide consumers with the full utility of the vehicles. In contrast, E85 flex fuel vehicles and PHEVs can refill with gasoline if E85 stations or EVSE locations are not widely available.

For commercial retail outlets serving LDVs (not home fueling or home charging), larger sizes at prime locations enhance the business case for investing in a new station. This is partly due to increased revenues from non-fuel sales at convenience or big-box store locations. By comparison, NLDV retail outlet networks tend to have less demanding geographic coverage requirements, and outlets serving NLDVs can be located “behind the fence” at facilities accessible to dedicated public or private fleets, near exit ramps along interstates, or at central refueling locations such as airports or marinas.

The extent of the retail outlet infrastructure to support future low-carbon fuels is estimated using data on existing gasoline station networks and their geographic coverage. Retail outlets in urban areas are generally difficult to characterize due to data limitations, but a unique dataset with consistent urban and rural locations is used in this study (Homeland Security Infrastructure Program 2012). Urban area coverage metrics for the existing retail infrastructure in 2010 are reviewed in Table 4.7. Urban areas are categorized into three distinct region types: urban, semi-urban, and rural. Semi-urban areas serve as an intermediary category of relatively low-density urban areas, many being buffer areas around the periphery of higher population density urban areas. As indicated in the table, urban areas (as defined here) contain 66% of the U.S. population and rural areas contain 24%. Semi-urban areas contain 10% of the U.S. population, but have 60% lower population density than urban areas. Additional metrics indicated in Table 4.7 include land area by region type, stations per person, and stations per land area. The total number of stations contained in this database is about 107,000 stations, and these tend to be the larger retail outlets; the total number of gasoline stations reported from U.S. Census or NPN surveys is higher. However, this data set is representative of the spatial distribution of public retail outlets (Melaina 2003). The major benefit of using this gasoline station data set is that it offers consistent spatial data across both urban and rural stations.

The bottom portion of Table 4.7 indicates estimates for a sufficient threshold of stations to provide adequate fueling availability to all urban area residents in 2010. As discussed elsewhere (Melaina and Bremson 2008), many urban areas have a far greater number of stations per square mile than other cities of comparable population and population density. This, combined with the fact that station numbers have been declining nationally (Melaina 2007; NPN 2011), suggests that in some areas the gasoline station network may be approaching a low or minimal threshold of station coverage that is acceptable to local markets. However, market dynamics can vary among urban areas, and some markets retain more stations than others (Melaina and Bremson 2008). A graphical representation of how this study estimates this threshold coverage across the three region types (urban, semi-urban and rural) is shown in Figure 4.12. The number of stations per urban area is shown by region type (urban, semi-urban, and rural), and the solid black lines are statistical fits to the total number of stations per area as a function of population (Power functions are used for Urban and Semi-urban, Linear for Rural). Below the solid black lines are thresholds for Urban (circle), Semi-urban (square) and Rural (triangle) areas. The threshold stations for each area represent the number of retail outlets that is estimated to be sufficient to serve the population of the city from a geographic coverage or consumer convenience perspective. Having a greater number of stations above this threshold may be considered more than sufficient geographic coverage, perhaps resulting from market influences not directly related to consumer refueling convenience (Melaina and Bremson 2008). The bottom of Table 4.7 indicates metrics for these threshold stations.

Table 4.7. Metrics for Major Retail Outlets Serving the LDV Market in 2010

(Source: Homeland Security Infrastructure Program 2012, and U.S. Census)

Number of Areas per Region Type and Population Metrics in 2010

Region Type	Number of Areas	Population (million)	Percent of U.S. Population	Aggregate Population Density (people/sq mi)
Urban	66	204.0	66%	2,158
Semi-urban	128	29.8	10%	864
Rural	1154	75.1	24%	22
Total	1348	308.9	100%	87

Land area, average population density and land for across all areas within each region in 2010

Region Type	Total Land Area (sq mi)	Percent of U.S. Land Area	Ave. Population (people)	Ave. Land Size per Area (sq mi)
Urban	94,500	2.7%	2,645,885	1,224
Semi-urban	34,457	1.0%	229,360	267
Rural	3,436,724	96.4%	10,059	46
Total	3,565,681	100%	*na*	*na*

Gasoline Station Metrics by Region in 2010

Region Type	Gasoline Stations	Percent of Gasoline Stations	Stations per million persons (aggregate)	Stations per 100 sq mi (aggregate)
Urban	62,079	57%	304	65.7
Semi-urban	10,245	9%	344	29.7
Rural Cities	34,575	32%	460	1.0
Other	1,608	1.5%	na	na
Total	106,899	100%	346	3.0

Threshold Station Metrics by Region in 2010

Region Type	Threshold Stations	Percent of Gasoline Stations by Area Type	Stations per million persons (aggregate)	Stations per 100 sq mi (aggregate)
Urban	41,465	67%	203	43.9
Semi-urban	7,412	72%	249	21.5
Rural	25,309	73%	337	0.74
Total	74,186	69%	240	2.1

Notes: Rural cities include areas more than 5000 people in 2010. "Other" is remaining stations, presumably located along interstates and rural highways.

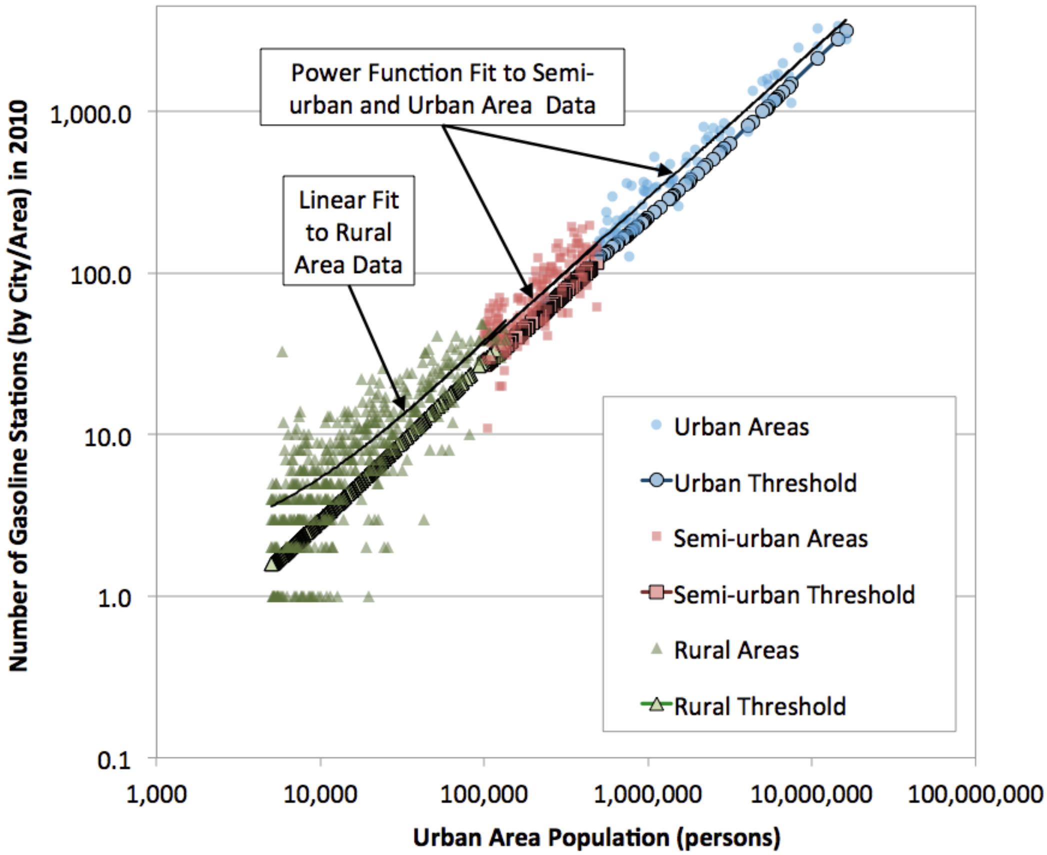


Figure 4.12. Number of gasoline stations per urban area as a function of population (2010)

According to this estimate, to provide all urban areas with threshold coverage would require approximately 74,000 stations, which is about 69% of the total number of stations serving these cities in 2010 in this database. Of course, geographic coverage is not the only factor influencing retail station market dynamics, and additional stations beyond this threshold level would continue to be sustained if supported by local market demands.

These two parametric representations of retail outlet coverage—all stations and threshold stations (the black and symbol-based lines, respectively) in Figure 4.12—are used to estimate the total and threshold numbers of retail outlets by region type in 2050. Table 4.8 shows additional assumptions and results. A major assumption is the increase in population and population density of urban and semi-urban areas, which is summarized at the top of the table. Increased density is a significant assumption, given that average metropolitan area population density decreased between 1950 and 1990, but it is consistent with a carbon-constrained future scenario in which the LDV VMT demand declines (Porter et al. 2013). The numbers of total and threshold stations, and trends in stations per square mile, follow from these demographic assumptions. As indicated, the total number of stations increases to about 134,300 by 2050, a 26% increase over the number of stations in 2010. The total number of threshold stations increases to about 94,600, a 28% increase over the number of threshold stations in 2010. The general trend to 2050 is that stations are added to urban areas and fewer stations serve semi-urban and rural areas. This follows from the assumption of increasing population density within urban areas. This trend determines the baseline for retail station expansion out to 2050, and is explained in more detail below.

The most relevant trends for determining equivalent refueling service in 2050 for LDVs are shown in two metrics: stations per million persons and stations per land area. Changes for these metrics are compared graphically in Figure 4.13 for each region and for the national average. “Stations per 100 square miles” increases slightly for both total stations and threshold stations, while "stations per million persons" declines slightly for both types. Fuel use per person is assumed to decline while urban density is assumed to increase, resulting in general availability of stations in 2050 that is comparable to current availability. The estimated number of total stations in 2050 may actually be on the high end because reduced fuel use per station will increase competition between stations and possibly contribute to station closures. The threshold and total station estimates are therefore likely bounds on a range, within which falls the number of fueling stations that would provide sufficient coverage by 2050.

Table 4.8. Metrics for Major Retail Outlets Serving the LDV Market in 2050

Number of Areas per Region Type and Population Metrics in 2050

Region Type	Number of Areas	Population (million)	Percent of U.S. Population	Aggregate Population Density (people/sq mi)
Urban	66	329.3	75%	2,539
Semi-urban	128	43.9	10%	910
Rural	1154	65.9	15%	19
Total	1348	439.0	100%	123

Land area, average population density and land for across all areas within each region in 2050

Region Type	Total Land Area (sq mi)	Percent of U.S. Land Area	Ave. Population (people)	Ave. Land Size per Area (sq mi)
Urban	129,663	3.6%	4,271,065	1,679
Semi-urban	48,261	1.4%	370,239	368
Rural	3,387,758	95.0%	8,819	64
Total	3,565,681	100%	*na*	*na*

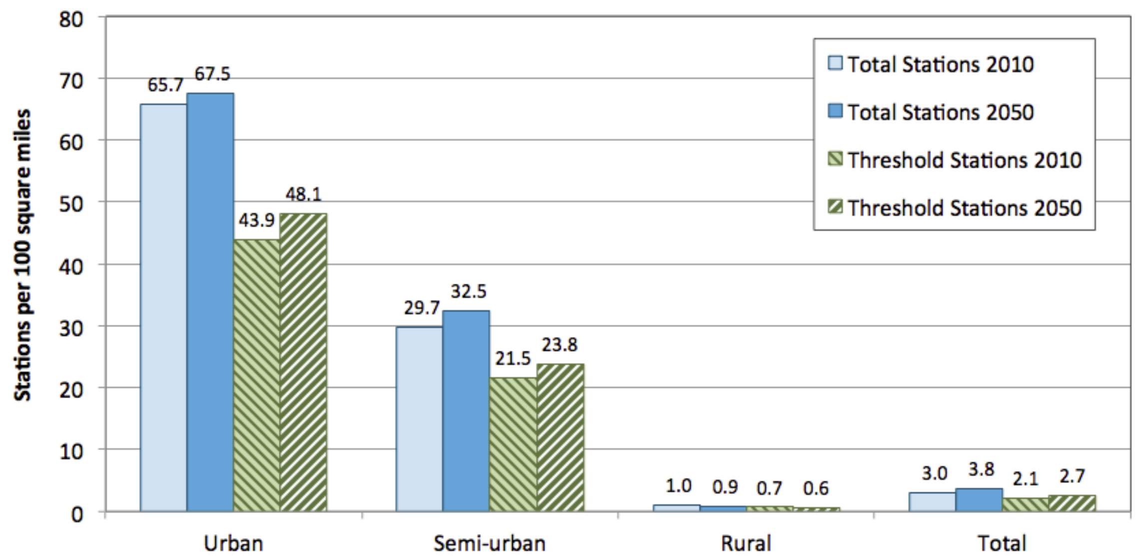
Gasoline Station Metrics by Region in 2050 (maintaining coverage similar to 2010)

Region Type	Gasoline Stations	Percent of Gasoline Stations	Stations per million persons (aggregate)	Stations per 100 sq mi (aggregate)
Urban	87,499	64%	266	67.5
Semi-urban	15,680	12%	357	32.5
Rural Cities	31,126	23%	473	0.9
Other	1,608	1.2%	na	na
Total	134,305	100%	306	3.8

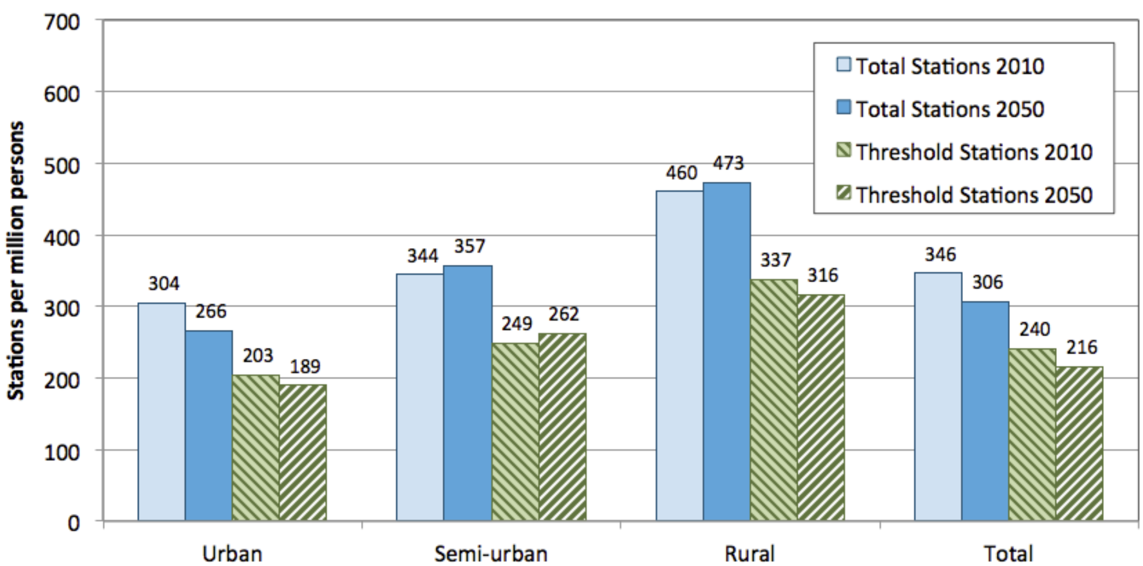
Threshold Station Metrics by Region in 2050 (maintaining 2010 threshold coverage)

Region Type	Threshold Stations	Percent of Gasoline Stations by Area Type	Stations per million persons (aggregate)	Stations per 100 sq mi (aggregate)
Urban	62,320	71%	189	48.1
Semi-urban	11,498	73%	262	23.8
Rural	20,790	67%	316	0.61
Total	94,608	70%	216	2.7

Another metric, the average driving time to the nearest station, was developed by Nicholas and Ogden (2006) to estimate minimal coverage needs for hydrogen stations. This analysis determines the average driving time in minutes for all households in an urban area as the number of installed hydrogen stations increases over time. Candidate hydrogen refueling locations are determined based upon existing gasoline station locations, and new hydrogen station locations are determined based upon an optimization routine that minimizes the average driving time. The result is a sequence of locations ordered such that the average driving time for all urban residents is reduced over time with the least number of stations. The results of this analysis are summarized in Nicholas et al. (2004) for four metropolitan areas in California: Sacramento, San Diego, San Francisco, and Los Angeles. The total number of stations required is expressed as a percentage of existing gasoline stations, and this result is reported as a function of the average driving time and the population density of the city. In the comparison across the four cities, a greater percentage of stations with hydrogen is required in lower population density cities than higher density cities to achieve the same average travel time.



(a)



(b)

Figure 4.13. Total and threshold stations per land area (a) and per million persons (b) in 2010 and 2050

In this analysis, the correlations from Nicholas and Ogden (2006) are applied to estimate the number of stations needed in all U.S. urban areas to achieve particular average travel times. Similar correlations could be made with results from other bottom-up models, such as the STREET model (Stephens-Romero et al. 2010). Although approximations were necessary to apply this method to the geographic regions as defined in this analysis, the two methods estimate comparable station number to travel time correlations. The result of extending the correlation for three-minute stations to projected demographics for all U.S. urban areas in 2050 is summarized in Figure 4.14. Urban areas are rank ordered by population density, with the cumulative population of 350 million urban residents living in cities with greater than 1,000 people per square mile indicated on the horizontal axis. As shown, approximately 15,300 carefully located stations would be sufficient to establish an average travel time of 3 minutes across all of these cities, and approximately 2,000 stations would be sufficient for the 100 million people living in the highest population density cities. The number of stations in each city would increase over time if market share increased, but these results give some indication of the number of stations required to establish a consistent level of availability across all U.S. urban areas in 2050. Establishing this level of convenience would therefore require approximately 11% of the 134,000 gasoline stations projected for the U.S. in 2050 (see Table 4.8).

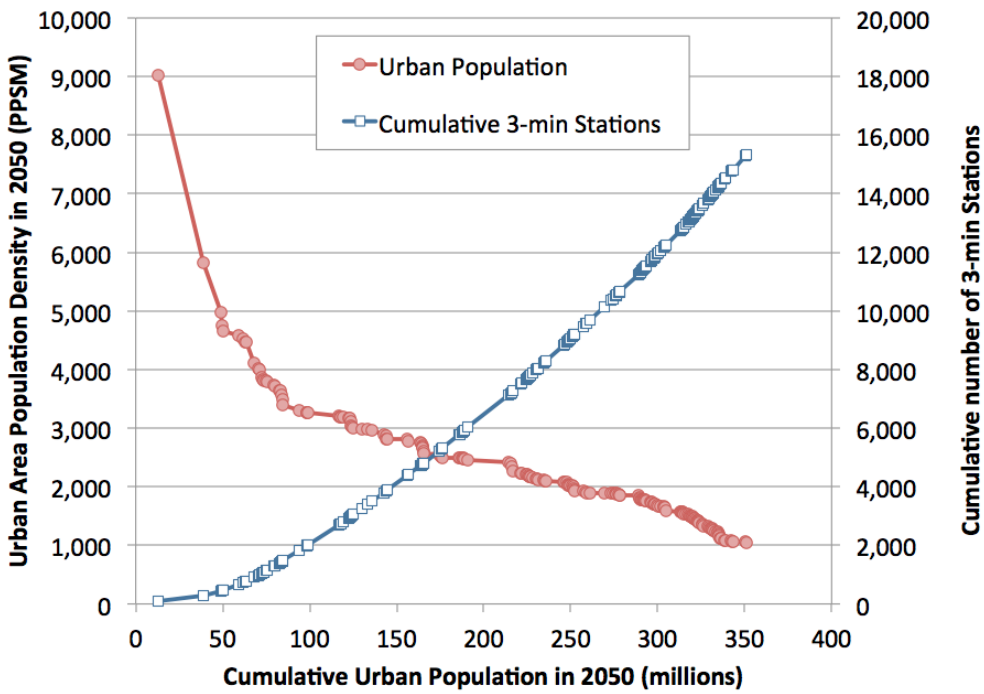


Figure 4.14. Cumulative three-minute-drive-time stations ordered by urban area population density in 2050

PPSM = people per square mile

This geographic analysis of retail infrastructure expansion is relevant to liquid fuels, CNG, and hydrogen, but not as relevant to EVSE because the driving and recharging behavior of PEV drivers would be distinct from that of other LDV drivers and because the recharging time for PEVs is much different than that for other LDVs. To estimate the number and types of EVSE that might be installed to support large PEV fleets in 2050, some simplifying assumptions are needed about when drivers will recharge and which types of charging stations they will use. To date, sufficient data are not available to provide an empirical basis for future projections of these behavioral and infrastructure development trends. Ultimately, the attractiveness of options such as home charging versus work charging would depend upon the relative costs and convenience of each option and the utility provided to decision makers. These decision factors will change as vehicle and charging technologies improve over time, and market players such as utilities or other commercial entities may play significant roles in determining future charging regimes through their influence on charging infrastructure, financing, and rate structures.

For EVSE, we assume that home charging dominates for PEVs, and that a significant fraction of PEV drivers charge at work. Although commercial Level 2, direct-current fast-charging stations, and inductive in-roadway charging may prove to be major components of a robust EVSE infrastructure, they are not included in the scope of the cost analysis. Table 4.9 summarizes assumptions in 2020 and 2050 for both PHEVs and BEVs (with PHEVs including plug-in FCEVs) charging via Level 1 at a residence or apartment complex and via Level 2 at a residence or work. Estimates of nominal costs, charging events, utilization rates, and resulting costs per kilowatt-hour are shown for comparison. Actual costs in the scenarios vary as vehicle efficiencies improve over time and as EVSE capital costs decline out to 2050. As is the case for all retail infrastructure costs in this study, a fixed charge ratio of 0.132 is assumed in the calculation of a levelized cost of energy (LCOE) (cf. Ruth et al. 2013), which is shown on both a kilowatt-hour and a gallon of gasoline equivalent basis. The LCOE results vary among charging options and are weighted based upon an assumption about the total number of electric-miles driven on electricity from each option. As shown at the bottom of each table section for 2020 and 2050, a blended LCOE result is calculated based upon these electric-mile percentages. Based upon these assumptions, BEVs have a higher cost of charging per kWh but drive a larger number of electric-miles per day than PHEVs.

Nominal retail infrastructure costs for liquid fuel stations (e.g., gasoline, diesel, or infrastructure-compatible biofuels), CNG stations, and hydrogen stations are shown in Table 4.10, with the same LCOE approach used for the retail EVSE costs in Table 4.9. Capital costs for liquid fuel stations are back-calculated from an estimate of $0.10 per gallon markup for new, large retail stations (cf. EIA 2013) and an annual maintenance cost estimate of 2.4% of total capital. Because the economies of scale are significant, retail costs for CNG and hydrogen stations are based upon small and large station sizes, with the percentage of total fuel volume from each type shifting toward larger stations in 2050 and therefore achieving greater economies of scale.

Table 4.9 and Table 4.10 provide details on retail infrastructure cost estimates for the major fuel types, and Table 4.11 condenses these cost assumptions to provide a more cursory side-by-side comparison. Again, these are nominal values shown for comparison, while the calculations within each scenario are continuous by year and depend upon the fleet-average fuel economies of the vehicles consuming each fuel type. Two additional retail cost metrics are indicated in Table 4.11: capital costs per mile driven ($/100 miles) and replacement costs per fuel energy delivered to vehicles ($ per gasoline gallon equivalent). The metric of capital cost per mile driven may be interpreted as an indicator of the capital intensity of each retail type, though this value must be combined with upstream production and delivery costs to compare the full costs passed on to consumers upon refueling or recharging (see Section 4.1 for cost comparisons). This per-mile basis does incorporate the influence of vehicle fuel economy, but a more complete cost assessment would also take into account vehicle purchase price and operating costs (DOE 2012; Nguyen and Ward 2013). The replacement costs represent a simplified approach to capturing the stock turnover of retail equipment. It is assumed that retail equipment must be replaced every 15 years on average. These replacement costs are incorporated into the annual time series of fuel demand in each scenario and are phased in gradually for new fuels.

Cost estimates for EVSE installations are highly variable today, and projections over the long term such as those presented here involve a large number of uncertainties. The estimates for blended costs per unit in Table 4.9 and Table 4.11 are assumed for a commercial success scenario with significant market share and high-volume EVSE deployment; variations in factors such as streamlined permitting, installation labor, technological learning, and efficient utilization could result in significantly higher costs, even over the long term. For example, the 2020 capital costs indicated in Table 4.9 could be assumed as 2050 costs in the event that there were limitations on reducing installation costs or demand for enhanced EVSE features that add cost. Combined with a shift in the percent of fleet electric miles for BEVs to more Level 1 charging (45%) and more Level 2 work charging (30%), capital costs per charger could be elevated to $1,500 per unit for PHEVs and $2,750 per unit for BEVs. Similarly, the market success of DC fast charging or roadway electrification, or other significant shifts in the fraction of electric miles from different EVSE types, would also significantly change the blended capital cost per charger or per 100 electric miles.

Combining the number of stations needed to reach sufficient geographic coverage with per-station cost assumptions, we can estimate total retail cost and coverage results for each scenario. Retail infrastructure capital costs are shown as annual cash flows for each scenario in Figure 4.15. Replacement costs are shown with grey bars, and each fuel type is color coded. These costs represent the amount of capital that would need to flow into each retail infrastructure type to support major transportation end-use demands, including LDVs, M/HDVs, air, marine, and buses. The degree to which these costs may also apply for rail and military application is more uncertain, but we assume that costs are comparable on a per-gallon basis and include those costs in the totals indicated. The retail costs for liquid fuels may be an upper estimate for NLDV applications, based upon the \$0.10/gallon retail markup assumption, and could be refined with additional information about refueling equipment requirements for NLDV modes. In general, the BAU scenario requires \$10–\$12.5 billion per year, with costs increasing over time with greater fuel demand. The Portfolio scenario peaks at about \$12.5 billion per year by 2037, the Combustion scenario requires slightly less capital than the BAU scenario does, and the Electrification scenario requires the most capital to expand and maintain retail infrastructure, reaching \$17 billion per year just before 2040 and then declining slightly to \$15 billion per year by 2050. Although the increases in retail capital costs in the Portfolio and Electrification scenarios are larger than those in the Combustion scenario, all retail costs are small (\$10–\$15 billion per year by 2050) compared to the long-term estimates of total fuel savings, which are on the order of \$150 billion per year by 2030 and \$200–\$230 billion per year by 2050 (see Figure 4.3).

Table 4.9. Electric Vehicle Supply Equipment Assumptions and Nominal Recharging Regimes in 2020 and 2050

(Source: Capital costs from Melaina and Penev 2012).

EVSE Type	Level I Residence	Level I Apartment	Level II Residence	Level II Work	Level I Residence	Level I Apartment	Level II Residence	Level II Work	
Vehicle Type	**PHEV**				**BEV**				**Notes**
2020									
Total Capital Cost ($)	$750	$750	$2,300	$7,000	$750	$750	$2,300	$7,000	Melaina and Penev (2012)
Ave. daily charge (kWh/day)	7.3	36.4	9.6	32.1	8.3	41.4	10.7	35.8	
Average charges per day	1	5	1.2	4	1	5	1.2	4	One charge per vehicle, except Level II Residence
Average charge (kWh/charge)	7.3	7.3	8.0	8.0	8.3	8.3	8.9	8.9	
Electric miles per gge (mpgge)	100	100	100	100	110	110	110	110	Nominal values; gge = 124,340 Btu (HHV)
Ave. battery miles per charge (mi/ch)	20	20	22	22	25	25	27	27	Nominal values
Average battery size (mi)	25	25	25	25	75	75	75	75	Nominal values
Electric miles/day per vehicle (mi/d)	20.0	20.0	26.4	22.0	25.0	25.0	32.4	27.0	One charge per vehicle, except Level II Residence
Charger maintenace (cents/kWh)	$0.028	$0.006	$0.065	$0.060	$0.025	$0.005	$0.059	$0.054	Assume 0.1% of capital annually
Electricity price ($/kWh)	$0.107	$0.107	$0.107	$0.095	$0.107	$0.107	$0.107	$0.095	AEO2011 residential prices; commerical for work charging.
Charger cost only ($/kWh)	$0.07	$0.01	$0.15	$0.14	$0.06	$0.01	$0.14	$0.12	Includes maintenance cost
Charging LCOE ($/kWh)	$0.17	$0.12	$0.26	$0.23	$0.16	$0.12	$0.24	$0.22	
Charging LCOE ($/gge)	$5.03	$4.13	$6.53	$5.88	$4.90	$4.10	$6.26	$5.63	
Percent of all fleet e-miles	60%	20%	10%	10%	40%	15%	30%	15%	
Blended average all charger types	$0.18	$/kWh	$5.08	$/gge	$0.19	$/kWh	$5.29	$/gge	
2050									
Total Capital Cost ($)	$500	$500	$1,800	$6,000	$500	$500	$1,800	$6,000	Melaina and Penev (2012)
Ave. daily charge (kWh/day)	10.0	80.2	13.1	87.5	7.0	56.2	9.4	62.5	
Average charges per day	1	8	1.2	8	1	8	1.2	8	One charge per vehicle, except Level II Residence
Average charge (kWh/charge)	10.0	10.0	10.9	10.9	7.0	7.0	7.8	7.8	
Electric miles per gge (mpgge)	80	80	80	80	140	140	140	140	Nominal values; gge = 124,340 Btu (HHV)
Ave. battery miles per charge (mi)	22	22	24	24	27	27	30	30	Nominal values
Average battery size (mi)	26	26	27	27	90	90	90	90	Nominal values
Electric miles/day per vehicle (mi/d)	22.0	22.0	28.8	24.0	27.0	27.0	36.0	30.0	One charge per vehicle, except Level II Residence
Charger maintenace (cents/kWh)	$0.014	$0.002	$0.038	$0.019	$0.019	$0.002	$0.053	$0.026	Assume 0.1% of capital annually
Electricity price ($/kWh)	$0.139	$0.139	$0.139	$0.122	$0.139	$0.139	$0.139	$0.122	AEO2011 residential prices; commerical for work charging.
Charger cost only ($/kWh)	$0.03	$0.00	$0.09	$0.04	$0.05	$0.01	$0.12	$0.06	Includes maintenance cost
Charging LCOE ($/kWh)	$0.17	$0.14	$0.23	$0.17	$0.18	$0.14	$0.26	$0.18	
Charging LCOE ($/gge)	$5.07	$5.14	$6.58	$5.22	$5.86	$5.17	$7.19	$5.52	
Percent of all fleet e-miles	60%	20%	10%	10%	40%	15%	30%	15%	
Blended average all charger types	$0.17	$/kWh	$5.25	$/gge	$0.20	$/kWh	$6.10	$/gge	

Notes: Assuming $0.03/kWh markup over AEO prices by 2050 for low carbon electricity.

Btu = British thermal unit; HHV = higher heating value; gge = gallon gasoline equivalent; kWh = kilowatt-hour; mi/ch = miles per charge; mi/d = miles per day; mpgge = miles per gallon gasoline equivalent

Table 4.10. Nominal Retail Cost Parameters for Liquid Fuel, CNG, and Hydrogen Stations in 2020 and 2050

Retail Cost Estimates (2005$)	Gsln/Dsl Average	CNG Small	CNG Large	Hydrogen Small	Hydrogen Large	Notes
2020						
Total Capital Cost (1000$)	$731	$1,140	$2,280	$1,700	$3,100	Gasoline capital is based on retail markup.
Volume (1000 gge/month)	95	30	90	15.0	34.0	
Average refill (gge/refill)	10	10	10	5	5	
Average refill events per day	312	99	296	99	224	
Percent of total fueling volume	100%	50%	50%	50%	50%	
Electricity per gge (kWh/gge)	na	1.4	1.38	2.5	2.5	
Electricity price ($/kWh)		$0.095	$0.095	$0.095	$0.095	AEO2011 Ref Case, Commerical rate
Cost of delivered fuel ($/gge)	$2.76	$1.52	$1.52	$5.50	$5.00	AEO2011Ref Case values
Maintenance cost ($/gge)	$0.02	$0.08	$0.05	$0.23	$0.18	Assuming 2.4% of capital cost per year
Retail markup ($/gge)	$0.10	-	-	-	-	Covers capital cost, gasoline station only
Station cost only ($/gge)	-	$0.63	$0.46	$1.71	$1.42	
Fuel LCOE ($/gal)	$2.86	$2.15	$1.98	$7.21	$6.42	
2050						
Total Capital Cost (1000$)	$731	$1,020	$2,040	$1,100	$2,000	Gasoline capital is based on retail markup.
Volume (1000 gge/month)	95	30	90	15.0	34.0	
Average refill (gge/refill)	10	10	10	5	5	
Average refill events per day	312	99	296	99	224	
Percent of retail fueling	100%	30%	70%	30%	70%	
Electricity per gge (kWh/gge)	na	1.4	1.38	2.5	2.5	
Electricity price ($/kWh)		$0.092	$0.092	$0.092	$0.092	Extrapolated from AEO2011 Ref Case, Commerical rate
Cost of delivered fuel ($/gge)	$3.03	$1.80	$1.80	$5.50	$5.00	AEO2011Ref Case values
Maintenance cost ($/gge)	$0.02	$0.07	$0.05	$0.15	$0.12	Assuming 2.4% of capital cost per year
Retail markup ($/gge)	$0.10	-	-	-	-	Covers capital cost, gasoline station only
Station cost only ($/gge)	$0.12	$0.57	$0.42	$1.18	$1.00	
Fuel LCOE ($/gal)	$3.13	$2.37	$2.22	$6.68	$6.00	

Notes. **All fuels:** Electricity rates ($/kWh) are from AEO2011 Reference Case, commercial rate. Retail operating cost is 2.4% of capital annually, for CNG and hydrogen only. **Gasoline:** Cost of Delivered Fuel is based upon prices from AEO2011 Reference Case, subtracting $0.10/gge for retail markup and $0.64/gge for taxes. Total Capital Cost for gasoline is backcalculated from assumed $0.10/gge Retail Markup using same fixed charge rate as other fuels. Maintenance cost is then a percent of that calculated capital. **CNG:** Capital costs, maintenance costs and electricity use rates from Johnson 2010. **Hydrogen:** Capital costs and sizes from recent study of near-term station costs (Melaina and Penev 2012); electricity usage from H2A default values for compression; electricity costs included within Station Cost Only sub-total.

CNG = compressed natural gas; Dsl = diesel; gal = gallon; gge = gallon of gasoline equivalent; Gsln = gasoline; kWh = kilowatt-hour; LCOE = levelized cost of energy

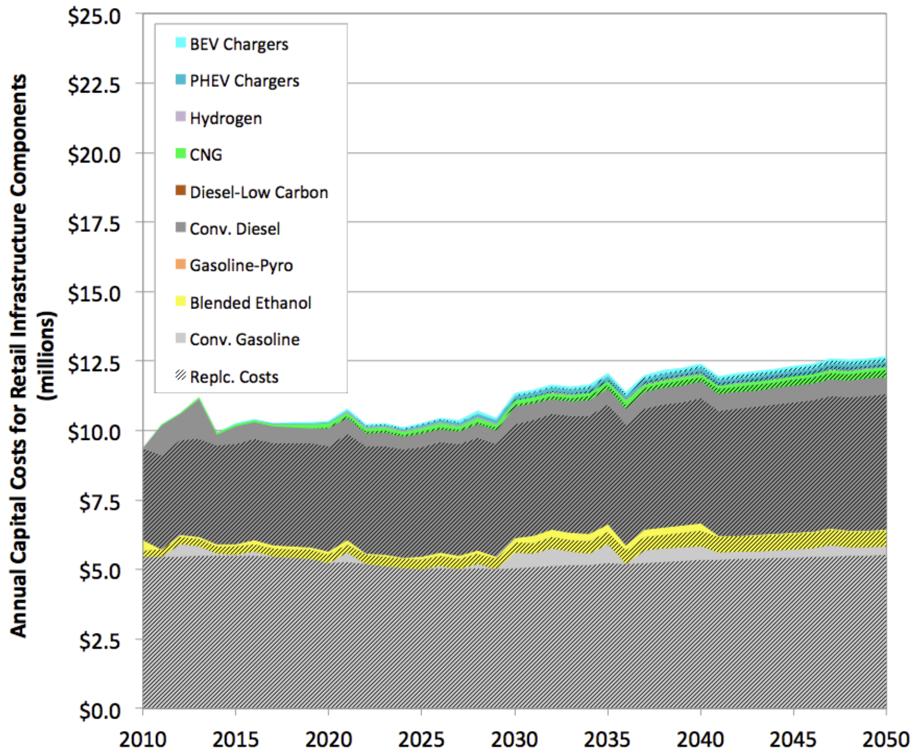
Table 4.11. Summary of Nominal Retail Capital Costs for Liquid, Gaseous, and Electric Charging Outlets

(Source: Melaina and Penev 2012)

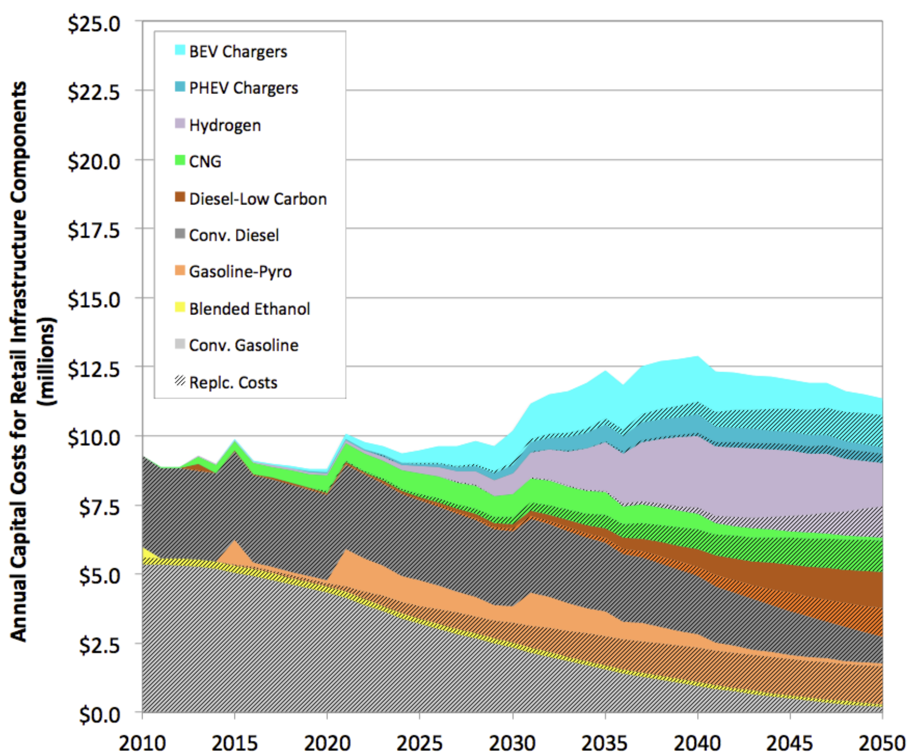
Retail Capital Costs per Mile (2005$)	Gsln/Dsl Stations	CNG Stations	Hydrogen Stations	EVSE for PHEVs	EVSE for BEVs	Notes
2020						
Capital cost per station ($M/stn)	$0.73	$1.43	$2.05			
Average station output (1000 gge/mo)	95	45	19.75			
Capital cost per charger ($)				$1,530	$2,153	
Average output per charger (gge/yr)				158.6	181.4	Varies with % e-miles by type.
Capital cost per new capacity ($/gge/yr)	$0.64	$2.64	$8.65	$9.65	$11.87	
Average vehicle fuel economy (mpgge)	30	30	65	80	120	
Capital cost per 100 miles ($/100mi)	$2.14	$8.80	$13.31	$12.06	$9.89	
Replacement cost per year ($/gge)	$0.04	$0.18	$0.58	$0.64	$0.79	Same as new capital each 15 years
2050						
Capital cost per station ($M/stn)	$0.73	$1.28	$1.33			
Average station output (1000 gge/mo)	95	45	19.75			
Capital cost per charger ($)				$1,180	$1,715	
Average output per charger (gge/yr)				$322	$235	Varies with % e-miles by type.
Capital cost per new capacity ($/gge/yr)	$0.64	$2.36	$5.59	$3.67	$7.31	
Average vehicle fuel economy (mpgge)	30	30	65	80	120	
Capital cost per 100 miles ($/100mi)	$2.14	$7.87	$8.60	$4.59	$6.09	
Replacement cost per year ($/gge)	$0.04	$0.16	$0.37	$0.24	$0.49	Same as new capital each 15 years

NOTES: **Gasoline:** Total capital cost is backcalculated from an assumed $0.10/gge retail markup, using same fixed charge rate as other fuels. **CNG:** Capital costs from Johnson 2010. **Hydrogen:** Capital costs from recent study of near-term station costs (Melaina and Penev 2012). **EVSE:** Capital costs are equal to costs by type, and weighted by the percent of fleet e-mile values, both reported in Table 4.9.

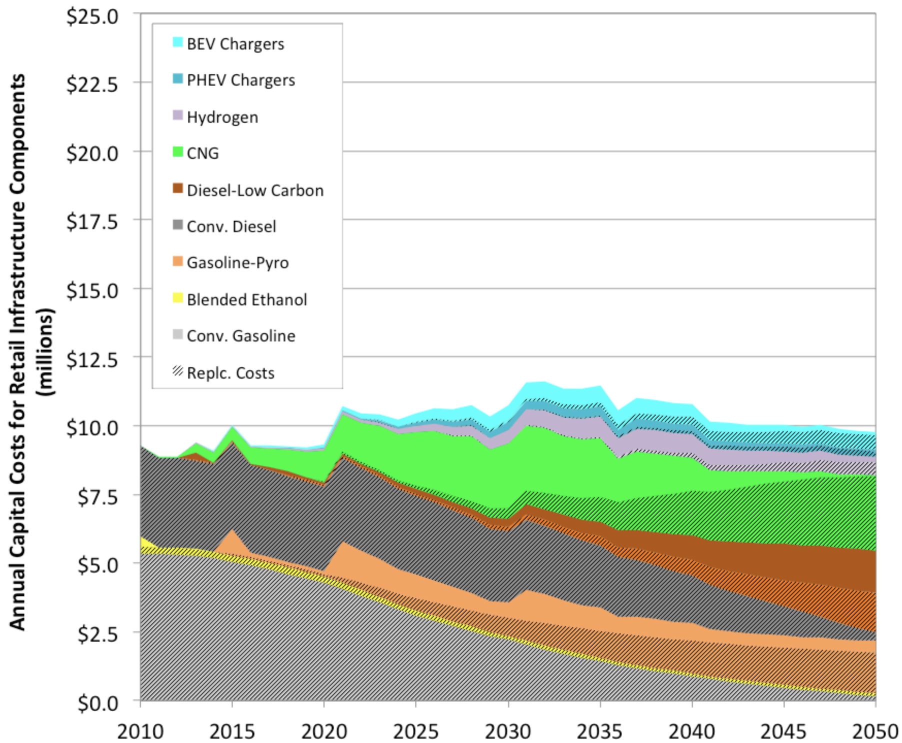
CNG = compressed natural gas; Dsl = diesel; gal = gallon; gge = gallon gasoline equivalent; Gsln = gasoline; kWh = kilowatt-hour; LCOE = levelized cost of energy; stn = station



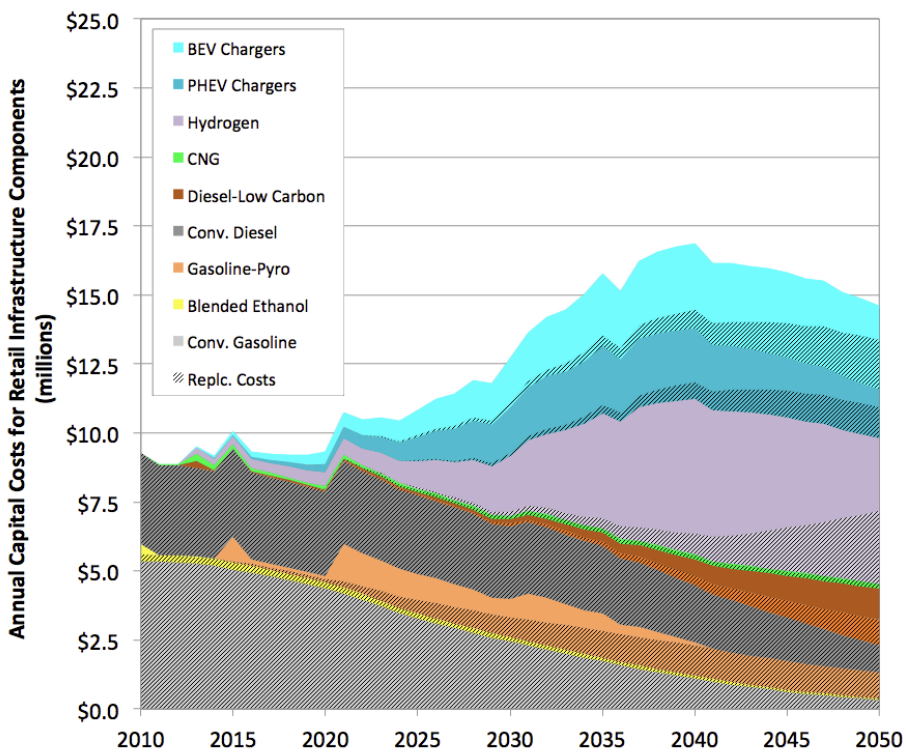
(a) BAU Scenario



(b) Portfolio Scenario



(c) Combustion Scenario



(d) Electrification Scenario

Figure 4.15. Nominal retail capital costs for each scenario

(a) BAU, (b) Portfolio, (c) Combustion, and (d) Electrification

Figure 4.16 and Figure 4.17 provide an overview of the retail infrastructure expansion and geographic coverage results for fuels supplied to the LDV market for each scenario in 2050. In Figure 4.16, the bar height indicates the number of stations. The three station coverage metrics are shown for reference: full coverage (comparable to today's urban gasoline network), threshold stations, and three-minute-drive-time stations. To provide coverage equivalent to the total gasoline stations today, approximately 134,300 stations would be needed in 2050, with about 31,000 stations serving rural cities. For threshold coverage in 2050, some 94,600 stations would be required. For three-minute-drive-time coverage in urban areas, some 15,300 stations would be required in 2050. For each scenario, the green bars indicate liquid fuel stations (e.g., gasoline blends), orange bars indicate CNG stations, and purple bars indicate hydrogen stations. BAU stations in 2010 are shown for reference. As expected, fewer stations would be needed in the low-carbon scenarios due to demand reductions and more efficient vehicles. Note that if the requirement on nominal station size were relaxed, the total number of stations in the low-carbon scenarios could be increased closer to the BAU number of stations. However, these nominal station sizes include both small and large stations for CNG and hydrogen; therefore, to some extent the results include smaller stations that increase coverage at the expense of economies of scale. If relative station size is constrained according to the small and large station sizes for CNG and hydrogen, increasing the total number of stations would result in many additional smaller stations and fewer large stations, which may not be tolerable from a market entry/exit perspective. This relative station size distribution is based upon empirical data that reflect market outcomes from existing gasoline station networks (Melaina and Bremson 2006).

In Figure 4.17, the units on the left vertical axis are the total number of stations represented by each bar. The right vertical axis is the percentage of total urban population served at three-minute-drive-time station coverage (squares) or the threshold station coverage (diamonds). The first three bars on the left-hand side of the figure indicate the same reference coverage metric requirements shown in Figure 4.16. The other bars in the figure are the same station numbers shown as stacked bars in Figure 4.16. (CNG stations from the Electrification scenario are omitted due to their small number.) When compared to the station coverage numbers, two station types do not have enough stations to meet the three-minute coverage requirement, and all others only partially meet the threshold station requirement. The square symbols at approximately 55% of full coverage indicate that the number of CNG stations in the Portfolio scenario and the number of hydrogen stations in the Combustion scenario would be able to provide three-minute coverage to a maximum of 55% of the total urban area population. This population would only be served at the three-minute convenience level if these stations were all located in the cities with the highest population densities. If the stations were distributed to cover additional urban population beyond this 55%, they would provide a lower level of coverage. In terms of threshold coverage, these CNG and hydrogen stations would be able to serve 10%–12% of the total urban population in 2050, but again only if these stations were concentrated in cities with the highest population densities and installed at carefully chosen locations. These percentages of population served are therefore upper limits. A more likely outcome would be greater dispersion of stations, serving a larger percentage of the total urban population but at a lower level of convenience.

The percentages shown with the diamond symbols in Figure 4.17 indicate that threshold coverage would only be available to certain fractions of the total urban population for each fuel type. Again, this level of coverage would only be provided to these percentages of the urban population if the stations were concentrated in cities with the highest population densities. For example, the approximately 37,200 CNG stations deployed in the Combustion scenario could provide threshold coverage to 52% of the total urban population if all of the stations were concentrated in cities with the highest population densities.

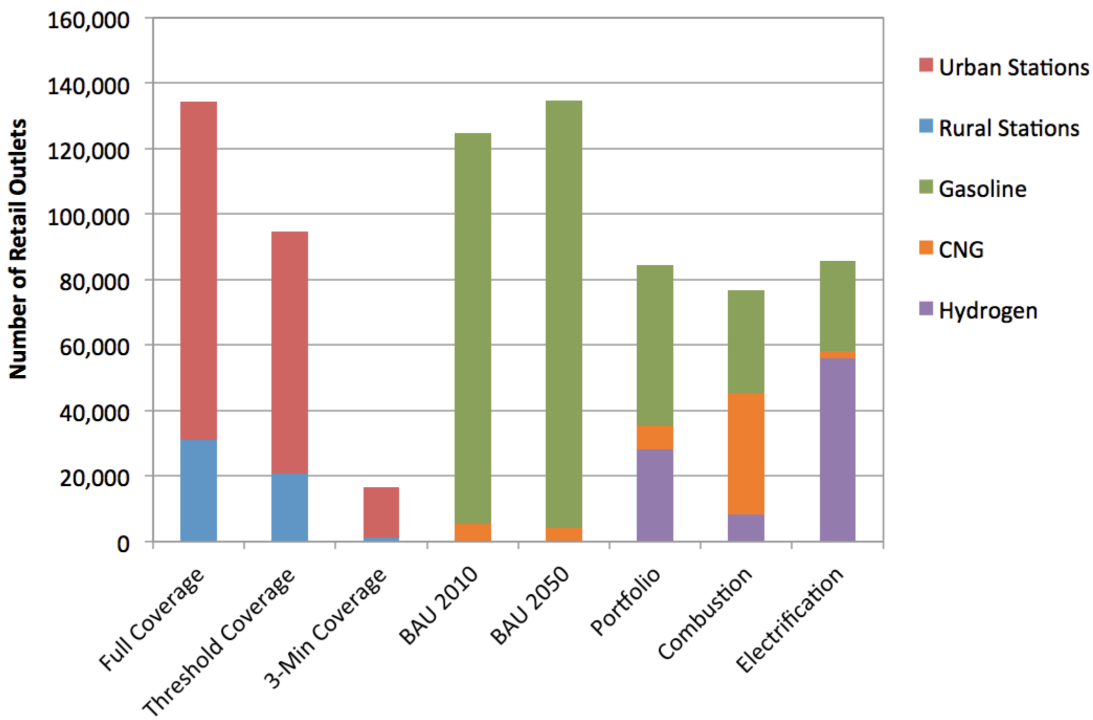


Figure 4.16. Retail coverage metrics and total number of retail outlets by scenario in 2050

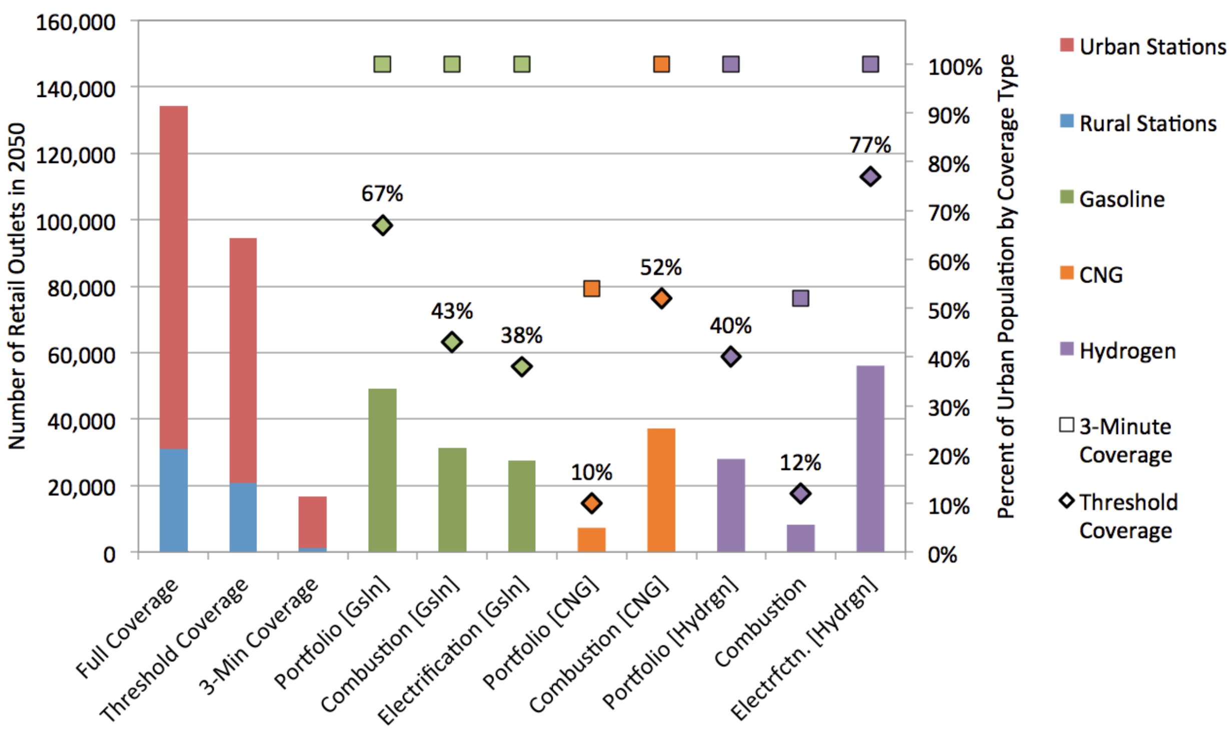


Figure 4.17. Number of retail outlets serving the LDV market in 2050 and percentage of urban population by coverage type

Percentage served may not sum to 100% because service is not mutually exclusive in all cases.

The future development path of the retail fuels business is uncertain. The market dynamics influencing fueling station networks under BAU conditions will be distinct from market dynamics in scenarios with carbon-constrained energy markets, a 10% LDV VMT reduction, LDVs that are very efficient, and urban areas that have become denser, resulting (presumably) in higher-value real estate located within cities. If the present trend continues and larger-volume stations continue to gain retail market share, the total number of retail stations is more likely to approach the threshold level of stations identified for 2050. If, alternatively, diversification of fuels and higher density cities occur while smaller-volume stations continue to maintain significant market share, the network could maintain higher levels of coverage and convenience out to 2050. Predicting these trends analytically would prove challenging. Most causal factors apparent today tend to favor a shift toward the threshold level of total retail stations.

If future retail sector market dynamics continue to maintain the full coverage level of stations, even with more efficient vehicles (meaning less fuel sold) and higher density cities, our constraints maintaining relatively large station sizes may be too restrictive, and a greater number of smaller low-carbon fuel stations would be able to serve greater fractions of the urban population at higher convenience levels.

It is important to consider that the threshold coverage percentages in Figure 4.17 may represent multi-fuel stations. For example, if business models prevailed to allow a larger number of smaller hydrogen stations to be co-located with all liquid fuel stations in the Portfolio scenario, those multi-fuel stations would be able to provide threshold coverage for both fuels to 67% of the urban population living in the cities with the highest population densities. The business models that would enable smaller stations (hydrogen, CNG, or others) to be co-located at enough liquid fuel stations to provide threshold coverage have yet to be developed. Some elements of such a business model might include generating higher in-store sales, raising fuel prices, cross-subsidizing unprofitable locations, or securing public incentives. As indicated in Figure 4.17, none of the low-carbon scenarios has a sufficient number of nominal stations to meet the threshold station coverage requirement. Retail stations would therefore either be more geographically sparse (and relatively larger, on average), resulting in some increased degree of inconvenience on the part of vehicle owners, or stations would be smaller and less likely to offer significant added retail revenue.

There are at least two key countervailing factors to consider: 1) increased inconvenience for vehicle owners would result in increased demand for refueling availability, presumably translating into a willingness to pay more for fuel to support greater accessibility through a larger number of retail stations, and 2) a clustering or patchwork pattern could emerge in which some new fuels would tend to achieve sustainable levels of market penetration in select clustered networks of urban areas or “megaregions” and only small market share in other regions (Regional Plan Association 2013). A geographically detailed market analysis framework would be required to examine these and other factors.

5. Conclusions

This study examines expansion of low-carbon fuel infrastructure to reach deep reductions in GHG emissions and petroleum use across the U.S. transportation sector. Three low-carbon fuel infrastructure expansion scenarios to 2050 were developed to explore a range of scenario metrics that are internally consistent and based upon a common set of cost and performance input assumptions.

The scenarios include a range of possible market shares for various low-carbon fuels, exploring different potential pathways to a reduction in overall transportation sector emissions to 80% of 2005 GHG emissions by 2050. The approach employed does not advocate emissions targets, predict market outcomes, or optimize technology costs. The scenario results are compared to market simulation results from the 2011 AEO Reference Case (EIA 2011), which are extrapolated to 2050 to develop a BAU reference scenario. The scenario results have been calculated using spreadsheet accounting tools to consistently track the combined influence of demand trends, end-use efficiency assumptions, and FCI reductions. The scenarios are based upon a bottom-up analytical approach that does not explicitly account for market dynamics, stakeholder decisions, or policy influences. The results are wholly dependent upon input assumptions; the scenarios do not represent predictions of future events.

Low-Carbon Scenarios

Three distinct low-carbon scenarios were developed, each resulting in GHG emissions 80% below 2005 levels by 2050 as well as deep reduction in petroleum fuel use. The scenarios were developed to highlight differences across a range of fuel infrastructure expansion trends. The BAU scenario and the three low-carbon scenarios are summarized as follows:

1. **Business as Usual:** No major change in policy support or industry initiatives to reduce petroleum use or GHG emissions. This scenario is based upon trends underlying the 2011 AEO Reference Case projections from EIA (2011), with extrapolations from 2035 to 2050.
2. **Portfolio:** Successful deployment of a variety of advanced vehicle and fuel technologies. This is the most diverse of the scenarios in terms of market growth and fuel mixes. It is assumed that the LDV sector experiences significant market growth for CNG, electric, and hydrogen vehicles.
3. **Combustion:** Market dominance of more efficient end-use technologies that are fueled by advanced biofuels and natural gas. The scenario also assumes significant adoption of low-carbon infrastructure-compatible fuels produced from biomass resources.
4. **Electrification:** Market dominance by electric drive vehicles in the LDV sector, including BEVs, PHEVs, and FCEVs. The FCI of electricity is 80% lower than the FCI of electricity in the BAU scenario, and hydrogen is predominantly produced from low-carbon energy sources. Low-carbon infrastructure-compatible fuels produced from biomass resources attain significant market share in NLDV markets.

Each of the low-carbon scenarios assumes significant reductions in demand for transportation services (e.g., VMT per year per LDV) and improvements in end-use efficiency (e.g., LDV fuel economy). As a result of these input assumptions, fuel demand is reduced significantly relative to BAU. Scenario input assumptions were then developed such that a variety of low-carbon fuels gain market share sufficient to reach the 80% GHG reduction goal by 2050. These fuels are produced from different energy resources and with different production and delivery technologies, and therefore have different FCI values. Each scenario has a unique combination of vehicle and fuel types, especially among drivetrains and fuels within the LDV sector. Demand reduction, end-use efficiency improvement, and low-carbon liquid biofuels are explored as the primary means of reducing GHG emissions in NLDV markets.

Each scenario is evaluated with respect to four criteria: fuel costs, energy resource availability, fuel production capacity expansion, and fuel retail infrastructure expansion. The results of these evaluations are summarized below.

Lower Fuel Costs

Based upon the long-term cost estimates, we find that each scenario results in total fuel costs lower than the fuel prices reported in the 2011 AEO Low Oil price case (EIA 2011). Low total fuel costs result from assumptions of change in technologies and market success: demand intensity reductions, energy efficiency improvements, and continued cost reductions and performance improvements in alternative fuel supply technologies. These costs include bottom-up estimates for infrastructure components across the supply chain, but do not address market barriers, market competition, or relative prices. Compared to total fuel expenditures in the BAU scenario, fuel cost estimates in the low-carbon scenarios suggest savings on the order of $200 to $1,000 billion per year by 2040–2050 when compared to the AEO Low Oil price case and High Oil price case, respectively. While fuel prices realized in the market would likely be higher than these fuel cost estimates, particularly in the early growth years due to market barriers and high investment risk premiums, the estimate of lower total fuel costs for the low-carbon scenarios highlights the opportunity for advanced fuel–vehicle systems to provide economic benefit and to mitigate the economic risks associated with high oil prices.

Adequate Energy Resource Availability

The low-carbon scenarios require significant investment in fuel supply infrastructure to enable diversification of transportation energy supply beyond petroleum to a variety of low-carbon and domestic energy resources. An assessment of the adequacy of these resources is therefore essential in evaluating the infrastructure investment. The assumptions about demand reduction and end-use efficiency result in reduced fuel use, and the projected biomass resource base described in the BTS2 (DOE 2011) of over 1 billion dry short tons (over 20 exajoules) would be more than adequate to support the 630–830 MDT estimated biomass use from the low-carbon scenarios. This report does not address competition for biomass throughout the energy sector. Also, the low-carbon scenarios do not place excessive demands on natural gas or renewable sources of electricity.

Comparable Fuel Production Capacity Expansion

Expansion of fuel production infrastructure in the low-carbon scenarios is about twice as large as in the BAU scenario. If pyrolysis oil processing can leverage existing petroleum refinery facilities, requirements for new low-carbon fuel production capacity infrastructure would be significantly lower. Demand intensity reduction and increased end-use efficiency in the low-carbon scenarios result in less new fuel production capacity required per vehicle or per mile traveled. The low-carbon scenarios, as constructed, suggest that conventional petroleum refining capacity would be idled at a more rapid rate than infrastructure-compatible fuel production capacity (e.g., pyrolysis oil fuels) would grow. The production capacity expansion for other low-carbon fuels (e.g., electricity, hydrogen) would be less than the new total conventional petroleum refining capacity expected in the BAU scenario between 2010 and 2050.

Coverage Challenges for Retail Infrastructure Expansion

Expansion requirements for retail infrastructure components, such as the number of refueling or recharging stations needed to serve a particular urban market, depend upon assumptions about market growth, urban area population density trends, and retail sector market dynamics to 2050. For some fuels that require new retail infrastructure, such as natural gas or hydrogen, it may prove challenging to provide sufficient geographic coverage while maintaining economically favorable station sizes. Sufficient retail infrastructure availability is a key market development issue for alternative fuels.

Recommendations for Additional Research

Additional research could improve the understanding of issues relevant to low-carbon fuel infrastructure expansion, including:

- Explore decision-making around investments in fuel production and retail infrastructure, including evaluating fuel-specific costs, technical challenges, market opportunities and barriers, policy and financing mechanisms, and environmental and social effects.
- Assess fuel infrastructure expansion costs in the context of the total cost of driving, including fuel costs, vehicle ownerships costs, and environmental and social impacts associated with fuel use and transportation services.
- Understand consumer vehicle purchase decisions and the influence of spatial proximity and geographic coverage of different types of refueling infrastructure (for electricity, liquid fuel, LNG, CNG, and hydrogen), in different locations (residences, worksites, and publicly accessible sites), and with different refueling times (e.g., Level 1 vs. Level 2 EVSE) and vehicle ranges (e.g., BEVs vs. PHEVs).
- Explore the potential role of public-private partnerships (including involvement of utilities or current fuel providers) in supporting infrastructure planning and expansion, and in overcoming market barriers.
- Analyze markets for various vehicles and fuels at a geographically detailed level, to understand region-specific effects on technology roll-out and the potential for regionalized markets, including the influence of state and local policy incentives.

A variety of vehicle and fuel technologies could reduce GHG emissions and petroleum use in the transportation sector over the long term. The scenarios presented here provide some insight into key trends, challenges, and benefits associated with the expansion of infrastructure associated with those technologies. Further work to extend this and similar studies can provide an improved understanding of investment risk, consumer expectations, market dynamics, geographic variability, and stakeholder coordination. As new lessons are learned from ongoing deployment activities, and as new vehicle platforms are introduced and low-carbon fuel technologies are improved, the capabilities of analytic tools can also be improved to further inform decisions made by industry stakeholders and policy makers.

Appendix A: Indirect Land Use Change

Biofuel assessments (e.g., Farrell et al. 2006) have estimated that biofuels can help the United States reduce GHG emissions. However, some studies have highlighted the potential that biofuel-induced global land-use change can offset the emissions reduction (Searchinger et al. 2008; Fargione et al. 2008). When land is converted to agricultural production, carbon can be released from soils and above-ground biomass—a flow of carbon from terrestrial stocks to the stock of atmospheric carbon that contributes to climate change. The IPCC *Special Report on Renewable Energy Sources and Climate Change Mitigation* provides an overview of biomass as an energy resource and includes a discussion of direct and indirect land use change (Chum et al. 2011). This carbon flow can be large compared to the potential GHG benefits from using biofuel instead of fossil-derived gasoline, possibly exceeding it during the study time period. The net effect depends on soil and vegetation characteristics of the land in question (determining the original terrestrial carbon stock), the initial land use changes, ongoing management practices, and resulting soil characteristics (determining how much carbon remains in the soil and how much flows to atmospheric carbon), and the displacement of fossil fuel (depending on the relative efficiencies of energy conversion and life cycle fossil fuel emissions). These studies prompted efforts to include land-use change estimates in national and state biofuel policies, to improve quantification of these effects.

Land-use change may be characterized as direct or indirect, depending on the nature of the causal relationships. Biofuel-induced direct land-use change occurs when biofuel crops are grown on land that had been used in other ways. Direct land-use change is an observable phenomenon that can be quantified with considerable confidence (e.g., Gibbs et al. 2008). This report uses BTS2 as the basis for availability and cost of biomass resource (DOE 2011). BTS2 documents direct land-use change in the United States, which increases with increasing quantity of biomass used for biofuel. Biofuel-induced indirect land-use change occurs when the demand for bioenergy crops increases, driving up prices for that crop and prompting increased crop production elsewhere, requiring either direct land-use change or increased yield. Substitute crop production may also increase and affect regional food crop prices in linked markets (Chum et al. 2011; Dale et al. 2011). Use of wastes and residues as biomass feedstock minimizes or eliminates land-use change.

Indirect land-use change cannot be directly measured nor isolated from the myriad other trends or events that can cause changes in land use patterns (Plevin et al. 2010). These additional causes include agricultural policies, agricultural product demand changes, and social changes. For policy analysis purposes, computer simulations or extrapolations of historical data are often used to evaluate total land use change with and without biofuels. The practice of land-use change modeling varies with regard to the modeling framework, boundary conditions, and other fundamental assumptions. Differences in methodologies for indirect land-use change cause variation in quantitative results across an order of magnitude and subsequent calculations of GHG emissions can even vary in sign (Berndes et al. 2010). While research continues, United States and European governmental organizations use available estimates of land-use change and associated GHG emissions in renewable fuel policies and related analyses (e.g., the U.S. Renewable Fuel Standard (U.S. Environmental Protection Agency 2010), EU Renewable Energy and Fuel Quality Directive (European Commission 2009), UK Renewable Transport Fuel Obligation (Gallagher 2008; United Kingdom Department for Transport 2013), and California's Low Carbon Fuel Standard (California Air Resources Board 2010).

Appendix B: Life Cycle GHG Emissions, Petroleum Consumption, and Biomass Consumption

Well-to-wheel (WTW) and well-to-tank (WTT) life-cycle GHG emissions, petroleum consumption, and biomass consumption data used in this analysis are listed in Table B.1 for the years 2005, 2020, and 2050 and an estimated long-term GHG emission reduction scenario called 2050+. The primary data source is the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model version 1.8d (Argonne National Laboratory 2011). Supplemental fuel pathways for microalgae-based fuels grown in open ponds, palm oil-based fuels, and municipal solid waste (MSW)-based fuels were partially generated in the GHGenius model version 3.19a [(S&T)^2 Consultants 2011]. Supplemental fuel pathways for pyrolysis oil-based fuels were partially based on GREET and a SimaPro v.7.2 model of pyrolysis oil processing to gasoline and diesel (Hsu 2011). MSW-based electricity used in vehicles was based on scenarios from Rigamonti et al. (2009) with GREET fuel economy and electricity transmission loss assumptions. Table B.2 lists the fuel economies taken from GREET that are used to calculate tank-to-wheel (TTW) life-cycle GHG emissions and petroleum consumption estimates in all applicable cases.

Life-cycle GHG emissions and petroleum consumption estimates for fuel pathways present in GREET were generated mostly based on default parameters, other than switching among feedstocks. Generally, fuel pathways for the year 2005 were modeled on GREET default assumptions. Fuel pathways for the 2020 and 2050 scenarios were both modeled based on default GREET assumptions for the year 2020. The GREET model does not estimate default values beyond 2020. The electricity grid for the years 2020 and 2050 and the associated life cycle GHG emission intensities were modeled based on the REF study's 80% renewables projections (NREL 2012). Parameters for specific fuel pathways were modified to reflect conversion efficiencies assumed for 2020 and 2050 as outlined in the TEF biomass utilization report (Ruth et al. 2013). If these conversion efficiencies were less than GREET 2005 defaults, then GREET 2005 defaults were accordingly modified.

Several GREET fuel pathways were modified to represent fuel pathways not contained explicitly in GREET, including lignocellulosic butanol, electricity generation from coal with CCS, renewable electricity pathways, landfill gas to electricity, and sugarcane ethanol from Brazil. Lignocellulosic butanol life-cycle GHG emissions, petroleum consumption, and biomass consumption estimates were generated based on modified GREET lignocellulosic ethanol pathways. Modifications were based on data from Tao and Aden (2011) and Mullins et al. (2011). The portion of Hsu's (2011) SimaPro model used for biomass conversion to pyrolysis oil and then to fuels was modified to reflect pyrolysis fuel conversion efficiencies as outlined in the TEF biomass utilization report (Ruth et al. 2013). These data were combined with lignocellulosic feedstock production and fuel distribution data from the GREET model to produce total life cycle GHG emissions, petroleum consumption, and biomass consumption estimates. With CCS, coal-based electricity life-cycle GHG emissions and petroleum consumption estimates were modified based on CCS rates from GREET's Fischer-Tropsch diesel pathways. Energy losses from CCS were taken from Spath and Mann (2004) to complete modeling of the coal with CCS electricity pathway. One hundred percent renewable electricity pathways were based on projecting the REF (NREL 2012) 80% renewables scenario to 100% renewables. The landfill-gas–based electricity pathway was created by connecting the landfill gas portion of the model, typically used for Fischer-Tropsch diesel production, to a natural gas plant producing electricity. GREET's sugarcane ethanol parameters were modified to reflect Brazilian data from Macedo et al. (2008) for 2005/2006 and 2020. This Brazilian paper projects greater 2005/2006 and 2020 life cycle productivity (i.e., ethanol and electricity for export) per unit of GHG emissions than under default GREET conditions.

The generation of the 2050+ scenario required modification of many GREET parameters towards a higher level of GHG emission reductions. The electricity grid for the 2050+ scenario and associated life-cycle GHG emission intensities were modeled based on a projection of the REF study's "80% in 2050" renewables scenario to a "90% in 2050+" renewables scenario. For other parameters, if projections out to 2050 based on existing GREET time series data (i.e., 1990–2020) were possible, the data from the last five years were used to alter the parameter. If there had been no expected change in the 2015–2020 timeframe the next applicable longer time frame (e.g., 2010–2020) was used. If parameter projections would have increased GHG emissions, changes were omitted (e.g., soybean fertilizer application). For traditional fossil fuel production routes, if projections based on GREET's time-series data were not possible, then no changes to the parameter were made for the 2050+ scenario. For the 2050+ scenario, no changes were made to parameters not deemed significant contributors to the life cycle. Significant contributors to life cycle were considered to be related to conversion efficiency, energy use, nitrogen application, and process fuel type (e.g., natural gas) at the refinery. Parameters pertaining to these significant contributors to life-cycle GHG emissions were altered based on proportional projections of a comparable parameter. For example, cellulosic ethanol post-2020 was assumed to have the same rate of efficiency improvements as that of corn ethanol from 1995 to 2020. Finally, if no time-series data were available, we assumed a 5% change in the parameter from the 2050 scenario that would lead to a decrease in life-cycle GHG emissions. A 5% change was less than the changes seen in most parameters with time-series data between 1990 and 2020.

The GHGenius model's algae-, palm oil-, and MSW-based fuel pathways (i.e., renewable diesel, biodiesel, and Fischer-Tropsch diesel) were generally unmodified to produce the WTT results listed in Table B.2. Like the GREET model, the electricity grid mix and associated life-cycle GHG emissions were modified to reflect the REF 80% renewables scenario for the years 2020 and 2050 (NREL 2012). Life-cycle GHG emissions and petroleum consumption estimates for the years 2020 and 2050 were based only on 2020 default parameter assumptions to remain parallel with 2050 scenarios from the GREET model that mostly used GREET's 2020 parameters. However, 2050 assumptions are available in GHGenius and were used to model the 2050+ scenario. GHGenius's electric grid assumptions were altered to reflect the projected 90% renewable conditions. Tank-to-wheel life-cycle GHG emission estimates were taken from GREET and combined with GHGenius WTT data to get WTW results. The one major structural change to GHGenius is that GHGenius's MSW and hydrogen production data were combined to produce MSW-based hydrogen life-cycle estimates of GHG emissions and petroleum consumption.

Completion of an electricity and hydrogen feedstock GHG emission intensity sensitivity analysis was possible for most fuel pathways. A module was created in which assumptions could be altered, based on the following basic equation for any fuel using electricity or hydrogen as fuel life cycle inputs:

Equation 1: $FCI_{new} = FCI_{orginal} + C_{Elec,LC} * (ECI_{new} - ECI_{original}) + C_{Hydrn,LC} * (HCI_{new} - HCI_{original})$

Where:

$\boldsymbol{FCI_{new}}$ = new fuel carbon intensity (gCO_2e/MJ_{fuel})

$\boldsymbol{FCI_{original}}$ = original fuel carbon intensity (GREET or GHGenius) (gCO_2e/MJ_{fuel})

$\boldsymbol{C_{Elec,LC}}$ = consumption, electricity over the life cycle (kWh/MJ_{fuel})

$\boldsymbol{C_{Hydro,LC}}$ = consumption, hydrogen over the life cycle ($MJ_{hydrogen}/MJ_{fuel}$)

$\boldsymbol{ECI_{original}}$ = original electricity carbon intensity (gCO_2e/kWh)

$\boldsymbol{ECI_{new}}$ = new electricity carbon intensity (gCO_2e/kWh)

$\boldsymbol{HCI_{original}}$ = original hydrogen carbon intensity ($gCO_2e/MJ_{hydrogen}$)

$\boldsymbol{HCI_{new}}$ = new hydrogen carbon intensity ($gCO_2e/MJ_{hydrogen}$)

Tables B.1 through B.8 provide additional data for calculations used in this study.

Table B.1. Life Cycle GHG Emissions and Petroleum Consumption Estimates Used in the Deployment Analysis Model for the Years 2020 and 2050

WTW and WTT data are listed with the source.

A) 2005

Delivered fuel product type(s)	Primary energy feedstock	Petroleum	GHG Emissions	Petroleum	GHG Emissions	Biomass Consumption	Author/Source	Year of Publication/ Version
Units --->		MJ_{input}/MJ_{fuel} produced	g/MJ_{fuel} produced	MJ_{input}/MJ_{fuel} produced	g/MJ_{fuel} produced	$MJ_{feedstock}/MJ_{fuel}$ produced	N/A	N/A
Scope--->		WTT	WTT	WTW	WTW	WTW	N/A	N/A
BD	Algae	0.01	-24	0.01	55	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.33	-11	-	-	0.12	GHGenius	3.19a
	Soybeans	0.08	-54	0.08	23	2.79	GREET	1.8d
Butanol	Corn	0.06	-12	0.07	59	1.47	GREET	1.8d
	Corn stover	0.17	-40	0.25	32	4.35	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Forest residues	0.37	-33	0.46	40	4.09	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Switchgrass	0.16	-12	0.24	61	4.57	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Woody	0.18	-45	0.26	27	5.20	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
CNG	Natural gas	0.01	16	0.01	76	-	GREET	1.8d
CD	Crude Oil	0.08	17	1.11	94	-	GREET	1.8d
CG	Crude Oil	0.08	17	1.10	93	-	GREET	1.8d
Electricity	100% renewable elec.	0.02	15	0.05	16	1.76	GREET	1.8d
	Average grid elec.	0.04	199	0.06	205	1.76	GREET	1.8d
	Coal w/ CCS	0.04	56	0.05	58	-	GREET, Spath et al.	1.8d, 2004
	Forest residues	0.18	32	0.25	33	1.76	GREET	1.8d
	Landfill gas	0.00	104	0.00	107	-	GREET	1.8d
	MSW	0.00	-16	0.00	-12	1.82	Rigamonti et al., GREET	2009, 1.8d
	Switchgrass	0.06	39	0.08	41	1.76	GREET	1.8d
	Woody	0.06	20	0.09	20	1.76	GREET	1.8d
Ethanol	Corn	0.07	-9	0.15	65	1.54	GREET	1.8d
	Corn stover	0.08	-56	0.16	16	2.33	GREET	1.8d
	Forest residues	0.16	-54	0.24	18	2.20	GREET	1.8d
	Sugarcane	0.09	-41	0.17	32	3.72	GREET, Macedo et al.	1.8d
	Switchgrass	0.08	-45	0.15	28	2.45	GREET	1.8d
	Woody	0.09	-61	0.17	11	2.79	GREET	1.8d
F-T Distillate	Coal w/ CCS	0.02	33	0.02	110	-	GREET	1.8d
	Corn stover	0.06	-64	0.06	9	2.41	GREET	1.8d
	Forest residues	0.15	-59	0.15	14	2.27	GREET	1.8d
	MSW	0.06	26	-	-	1.45	GHGenius	3.19a
	Natural gas	0.02	31	0.02	107	-	GREET	1.8d
	Switchgrass	0.05	-54	0.06	19	2.54	GREET	1.8d
	Woody	0.06	-66	0.06	7	2.88	GREET	1.8d
Hydrogen Gaseous	MSW	0.13	53	-	-	1.45	GHGenius	3.19a
	100% renewable elec.	0.04	23	0.23	76	1.84	GREET	1.8d
	Average grid elec.	0.07	293	0.28	902	1.84	GREET	1.8d
	Coal w/ CCS	0.02	28	0.06	93	-	GREET, Spath et al.	1.8d, 2004
	Natural gas	0.01	107	0.03	332	-	GREET	1.8d
	Natural gas w/ CCS	0.01	52	0.04	167	-	GREET	1.8d
	Switchgrass	0.06	42	0.18	136	1.34	GREET	1.8d
	Switchgrass w/ CCS	0.06	-122	0.19	-364	1.34	GREET	1.8d
	Woody	0.06	29	0.19	97	1.34	GREET	1.8d
	Woody	0.07	-146	0.20	-437	1.34	GREET	1.8d
Hydrogen - Gaseous via EtOH	Corn	0.11	121	0.34	377	1.97	GREET	1.8d
	Corn stover	0.24	75	0.74	235	2.99	GREET	1.8d
	Forest residues	0.54	86	1.65	270	2.81	GREET	1.8d
Hydrogen - Liquid	100% renewable elec.	0.07	29	0.29	96	1.89	GREET	1.8d
	Average grid elec.	0.09	380	0.36	1167	1.89	GREET	1.8d
	Coal w/ CCS	0.04	142	0.11	439	-	GREET	1.8d
	Natural gas	0.02	156	0.05	484	1.89	GREET	1.8d
	Natural gas w/ CCS	0.02	100	0.06	313	1.89	GREET	1.8d
	Switchgrass	0.09	42	0.28	134	1.89	GREET	1.8d
	Switchgrass w/ CCS	0.10	-128	0.29	-384	1.89	GREET	1.8d
	Woody	0.10	21	0.29	71	1.89	GREET	1.8d
	Woody w/ CCS	0.10	-161	0.31	-483	1.89	GREET	1.8d
Hydrogen - Liquid via EtOH	Corn	0.14	207	0.42	639	1.97	GREET	1.8d
	Corn stover	0.27	161	0.83	498	2.99	GREET	1.8d
	Forest residues	0.57	172	1.74	533	2.81	GREET	1.8d
LNG	Natural gas	0.01	18	0.01	78	-	GREET	1.8d
PO - Diesel	Corn stover	0.11	-51	0.21	24	1.69	Hsu, GREET	2011, 1.8d
	Forest residues	0.21	-46	0.33	30	1.59	Hsu, GREET	2011, 1.8d
	Switchgrass	0.10	-37	0.21	40	1.77	Hsu, GREET	2011, 1.8d
	Woody	0.12	-52	0.22	22	2.01	Hsu, GREET	2011, 1.8d
PO - Gasoline	Corn stover	0.11	-51	0.18	20	1.69	Hsu, GREET	2011, 1.8d
	Forest residues	0.21	-46	0.28	25	1.59	Hsu, GREET	2011, 1.8d
	Switchgrass	0.11	-37	0.17	34	1.77	Hsu, GREET	2011, 1.8d
	Woody	0.12	-52	0.18	19	2.01	Hsu, GREET	2011, 1.8d
RD	Algae	0.01	6	0.01	81	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.34	28	-	-	0.12	GHGenius	3.19a
RD - SuperCetane	Soybeans	0.07	-52	0.07	23	3.49	GREET	1.8d
RD - UOP-HDO	Soybeans	0.07	-49	0.08	26	2.69	GREET	1.8d
RG	Soybeans	0.08	-48	0.08	24	5.20	GREET	1.8d

B) 2020

Delivered fuel product type(s)	Primary energy feedstock	Petroleum	GHG Emissions	Petroleum	GHG Emissions	Biomass Consumption	Author/Source	Year of Publication/ Version
Units --->		$MJ_{input}/MJ_{fuel\ produced}$	$g/MJ_{fuel\ produced}$	$MJ_{input}/MJ_{fuel\ produced}$	$g/MJ_{fuel\ produced}$	$MJ_{feedstock}/MJ_{fuel\ produced}$	N/A	N/A
Scope--->		WTT	WTT	WTW	WTW	WTW	N/A	N/A
BD	Algae	0.01	-42	0.01	36	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.30	-16	-	-	0.12	GHGenius	3.19a
	Soybeans	0.05	-62	0.05	15	1.34	GREET	1.8d
Butanol	Corn	0.06	-17	0.06	54	1.47	GREET	1.8d
	Corn stover	0.16	-49	0.23	24	4.35	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Forest residues	0.26	-40	0.33	33	4.09	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Switchgrass	0.15	-20	0.23	53	4.57	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Woody	0.18	-49	0.26	24	5.20	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
CNG	Natural gas	0.01	15	0.01	72	-	GREET	1.8d
CD	Crude Oil	0.08	16	1.10	93	-	GREET	1.8d
CG	Crude Oil	0.08	15	1.06	90	-	GREET	1.8d
Electricity	100% renewable elec.	0.01	15	0.04	15	1.75	GREET	1.8d
	Average grid elec.	0.02	135	0.03	137	1.75	GREET	1.8d
	Coal w/ CCS	0.03	55	0.05	56	-	GREET, Spath et al.	1.8d, 2004
	Forest residues	0.11	25	0.16	25	1.75	GREET	1.8d
	Landfill gas	0.00	89	0.00	90	-	GREET	1.8d
	MSW	0.00	-16	0.00	-16	1.85	Rigamonti et al., GREET	2009, 1.8d
	Switchgrass	0.06	39	0.08	39	1.75	GREET	1.8d
	Woody	0.06	20	0.08	20	1.75	GREET	1.8d
Ethanol	Corn	0.05	-23	0.12	50	1.28	GREET	1.8d
	Corn stover	0.08	-64	0.15	8	2.33	GREET	1.8d
	Forest residues	0.12	-55	0.19	17	2.20	GREET	1.8d
	Sugarcane	0.09	-52	0.17	20	3.72	GREET, Macedo et al.	1.8d
	Switchgrass	0.07	-52	0.15	20	2.45	GREET	1.8d
	Woody	0.09	-64	0.16	8	2.79	GREET	1.8d
F-T Distillate	Coal w/ CCS	0.02	27	0.02	102	-	GREET	1.8d
	Corn stover	0.05	-66	0.05	8	2.41	GREET	1.8d
	Forest residues	0.09	-65	0.09	9	2.27	GREET	1.8d
	MSW	0.05	16	-	-	1.36	GHGenius	3.19a
	Natural gas	0.02	27	0.02	102	-	GREET	1.8d
	Switchgrass	0.05	-57	0.05	16	2.54	GREET	1.8d
	Woody	0.05	-67	0.05	6	2.88	GREET	1.8d
Hydrogen - Gaseous	MSW	0.13	29	-	-	1.36	GHGenius	3.19a
	100% renewable elec.	0.03	22	0.05	22	1.83	GREET	1.8d
	Average grid elec.	0.03	191	0.04	194	1.83	GREET	1.8d
	Coal w/ CCS	0.01	39	0.01	40	-	GREET, Spath et al.	1.8d, 2004
	Natural gas	0.01	99	0.01	101	-	GREET	1.8d
	Natural gas w/ CCS	0.01	44	0.01	44	-	GREET	1.8d
	Switchgrass	0.04	28	0.04	28	1.45	GREET	1.8d
	Switchgrass w/ CCS	0.04	-102	0.04	-103	1.45	GREET	1.8d
	Woody	0.04	18	0.04	19	1.45	GREET	1.8d
	Woody w/ CCS	0.05	-120	0.05	-122	1.45	GREET	1.8d
Hydrogen - Gaseous via EtOH	Corn	0.07	87	0.07	89	1.63	GREET	1.8d
	Corn stover	0.22	50	0.23	51	2.99	GREET	1.8d
	Forest residues	0.37	63	0.38	64	2.81	GREET	1.8d
Hydrogen - Liquid	100% renewable elec.	0.04	27	0.06	28	1.87	GREET	1.8d
	Average grid elec.	0.04	241	0.06	245	1.87	GREET	1.8d
	Coal w/ CCS	0.03	126	0.03	128	-	GREET, Spath et al.	1.8d, 2004
	Natural gas	0.02	140	0.02	142	-	GREET	1.8d
	Natural gas w/ CCS	0.02	82	0.02	84	-	GREET	1.8d
	Switchgrass	0.07	30	0.07	30	1.35	GREET	1.8d
	Switchgrass w/ CCS	0.07	-105	0.07	-106	1.35	GREET	1.8d
	Woody	0.07	14	0.08	14	1.35	GREET	1.8d
	Woody w/ CCS	0.08	-130	0.08	-132	1.35	GREET	1.8d
Hydrogen - Liquid via EtOH	Corn	0.08	137	0.08	139	1.63	GREET	1.8d
	Corn stover	0.24	100	0.24	101	2.99	GREET	1.8d
	Forest residues	0.38	113	0.39	115	2.81	GREET	1.8d
LNG	Natural gas	0.01	16	0.01	74	-	GREET	1.8d
PO - Diesel	Corn stover	0.11	-52	0.20	23	1.69	Hsu, GREET	2011, 1.8d
	Forest residues	0.16	-51	0.26	24	1.59	Hsu, GREET	2011, 1.8d
	Switchgrass	0.10	-37	0.20	39	1.77	Hsu, GREET	2011, 1.8d
	Woody	0.12	-53	0.22	22	2.01	Hsu, GREET	2011, 1.8d
PO - Gasoline	Corn stover	0.11	-52	0.17	19	1.69	Hsu, GREET	2011, 1.8d
	Forest residues	0.16	-51	0.22	20	1.59	Hsu, GREET	2011, 1.8d
	Switchgrass	0.10	-37	0.17	33	1.77	Hsu, GREET	2011, 1.8d
	Woody	0.12	-53	0.18	18	2.01	Hsu, GREET	2011, 1.8d
RD	Algae	0.01	-14	0.01	60	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.30	21	-	-	0.12	GHGenius	3.19a
RD - SuperCetane	Soybeans	0.04	-59	0.04	16	1.94	GREET	1.8d
RD - UOP-HDO	Soybeans	0.05	-56	0.05	18	1.55	GREET	1.8d
RG	Soybeans	0.04	-56	0.05	16	2.77	GREET	1.8d

C) 2050

Delivered fuel product type(s)	Primary energy feedstock	Petroleum	GHG Emissions	Petroleum	GHG Emissions	Biomass Consumption	Author/Source	Year of Publication/ Version
Units --->		MJ input/MJ fuel produced	g/MJ fuel produced	MJ input/MJ fuel produced	g/MJ fuel produced	MJ feedstock/MJ fuel produced	N/A	N/A
Scope--->		WTT	WTT	WTW	WTW	WTW	N/A	N/A
BD	Algae	0.01	-65	0.01	13	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.29	-19	-	-	0.12	GHGenius	3.19a
	Soybeans	0.05	-64	0.05	13	1.34	GREET	1.8d
Butanol	Corn	0.06	-21	0.06	50	1.47	GREET	1.8d
	Corn stover	0.11	-49	0.19	23	2.94	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Forest residues	0.18	-44	0.26	28	2.77	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Switchgrass	0.11	-30	0.18	43	3.09	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Woody	0.13	-49	0.21	24	3.52	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
CNG	Natural gas	0.01	11	0.01	69	-	GREET	1.8d
CD	Crude Oil	0.08	15	1.10	92	-	GREET	1.8d
CG	Crude Oil	0.08	13	1.06	88	-	GREET	1.8d
Electricity	100% renewable elec.	0.01	15	0.04	15	1.75	GREET	1.8d
	Average grid elec.	0.03	32	0.07	32	1.75	GREET	1.8d
	Coal w/ CCS	0.03	55	0.05	56	-	GREET, Spath et al.	1.8d, 2004
	Forest residues	0.11	25	0.16	25	1.75	GREET	1.8d
	Landfill gas	0.00	89	0.00	90	-	GREET	1.8d
	MSW	0.00	-16	0.00	-16	1.85	Rigamonti et al., GREET	2009, 1.8d
	Switchgrass	0.06	39	0.08	39	1.75	GREET	1.8d
	Woody	0.06	20	0.08	20	1.75	GREET	1.8d
Ethanol	Corn	0.05	-29	0.13	44	1.28	GREET	1.8d
	Corn stover	0.06	-58	0.14	15	1.88	GREET	1.8d
	Forest residues	0.10	-53	0.17	19	1.77	GREET	1.8d
	Sugarcane	0.05	-29	0.13	44	3.48	GREET, Macedo et al.	1.8d
	Switchgrass	0.06	-48	0.14	24	1.98	GREET	1.8d
	Woody	0.07	-57	0.15	15	2.25	GREET	1.8d
F-T Distillate	Coal w/ CCS	0.02	24	0.02	98	-	GREET	1.8d
	Corn stover	0.05	-66	0.05	7	2.41	GREET	1.8d
	Forest residues	0.09	-65	0.09	9	2.27	GREET	1.8d
	MSW	0.05	8	-	-	1.36	GHGenius	3.19a
	Natural gas	0.02	27	0.02	102	-	GREET	1.8d
	Switchgrass	0.05	-58	0.05	16	2.54	GREET	1.8d
	Woody	0.05	-67	0.05	6	2.88	GREET	1.8d
Hydrogen - Gaseous	MSW	0.13	4	-	-	1.36	GHGenius	3.19a
	100% renewable elec.	0.03	22	0.05	22	1.83	GREET	1.8d
	Average grid elec.	0.05	45	0.09	45	1.83	GREET	1.8d
	Coal w/ CCS	0.02	26	0.02	27	-	GREET, Spath et al.	1.8d, 2004
	Natural gas	0.01	91	0.01	92	-	GREET	1.8d
	Natural gas w/ CCS	0.01	33	0.01	34	-	GREET	1.8d
	Switchgrass	0.05	18	0.05	18	1.55	GREET	1.8d
	Switchgrass w/ CCS	0.05	-115	0.05	-117	1.55	GREET	1.8d
	Woody	0.05	8	0.05	8	1.55	GREET	1.8d
	Woody w/ CCS	0.05	-134	0.05	-136	1.55	GREET	1.8d
Hydrogen - Gaseous via EtOH	Corn	0.08	58	0.08	59	1.63	GREET	1.8d
	Corn stover	0.09	17	0.10	17	2.41	GREET	1.8d
	Forest residues	0.15	23	0.15	23	2.27	GREET	1.8d
Hydrogen - Liquid	100% renewable elec.	0.04	27	0.06	28	1.87	GREET	1.8d
	Average grid elec.	0.08	56	0.12	57	1.87	GREET	1.8d
	Coal w/ CCS	0.03	121	0.03	123	-	GREET, Spath et al.	1.8d, 2004
	Natural gas	0.02	140	0.02	142	-	GREET	1.8d
	Switchgrass	0.07	27	0.07	28	1.66	GREET	1.8d
	Woody	0.08	12	0.08	12	1.66	GREET	1.8d
Hydrogen - Liquid via EtOH	Corn	0.10	70	0.10	71	1.63	GREET	1.8d
	Corn stover	0.12	28	0.12	29	2.41	GREET	1.8d
	Forest residues	0.17	35	0.17	35	2.27	GREET	1.8d
LNG	Natural gas	0.01	16	0.01	74	-	GREET	1.8d
PO - Diesel	Corn stover	0.08	-55	0.18	19	1.10	Hsu, GREET	2011, 1.8d
	Forest residues	0.12	-55	0.22	20	1.03	Hsu, GREET	2011, 1.8d
	Switchgrass	0.08	-46	0.18	29	1.15	Hsu, GREET	2011, 1.8d
	Woody	0.09	-56	0.19	18	1.31	Hsu, GREET	2011, 1.8d
PO - Gasoline	Corn stover	0.08	-55	0.15	16	1.10	Hsu, GREET	2011, 1.8d
	Forest residues	0.12	-55	0.18	17	1.03	Hsu, GREET	2011, 1.8d
	Switchgrass	0.08	-46	0.15	24	1.15	Hsu, GREET	2011, 1.8d
	Woody	0.09	-56	0.16	15	1.31	Hsu, GREET	2011, 1.8d
RD	Algae	0.01	-37	0.01	38	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.30	18	-	-	0.12	GHGenius	3.19a
RD - SuperCetane	Soybeans	0.04	-61	0.04	14	1.94	GREET	1.8d
RD - UOP-HDO	Soybeans	0.05	-58	0.05	16	1.55	GREET	1.8d
RG	Soybeans	0.04	-59	0.05	14	2.77	GREET	1.8d

D) 2050+

Delivered fuel product type(s)	Primary energy feedstock	Petroleum	GHG Emissions	Petroleum	GHG Emissions	Biomass Consumption	Author/Source	Year of Publication/ Version
Units --->		*MJ input/MJ fuel produced*	*g/MJ fuel produced*	*MJ input/MJ fuel produced*	*g/MJ fuel produced*	*MJ feedstock/MJ fuel produced*	*N/A*	*N/A*
Scope--->		*WTT*	*WTT*	*WTW*	*WTW*	*WTW*	*N/A*	*N/A*
BD	Algae	0.02	-72	0.02	0	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.25	-25	-	-	0.12	GHGenius	3.19a
	Soybeans	0.04	-66	0.04	10	1.21	GREET	1.8d
Butanol	Corn	0.04	-37	0.03	31	1.15	GREET	1.8d
	Corn stover	0.10	-50	0.16	21	2.80	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Forest residues	0.12	-49	0.18	22	2.64	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Switchgrass	0.07	-42	0.13	28	2.95	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Woody	0.09	-53	0.15	18	3.35	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
CNG	Natural gas	0.00	11	0.00	63	-	GREET	1.8d
CD	Crude Oil	0.08	14	1.01	84	-	GREET	1.8d
CG	Crude Oil	0.08	11	0.97	80	-	GREET	1.8d
Electricity	100% renewable elec.	0.01	15	0.02	14	1.72	GREET	1.8d
	Average grid elec.	0.01	25	0.02	23	1.72	GREET	1.8d
	Coal w/ CCS	0.03	49	0.04	45	-	GREET, Spath et al.	1.8d, 2004
	Forest residues	0.06	18	0.08	16	1.72	GREET	1.8d
	Landfill gas	0.00	54	0.00	49	-	GREET	1.8d
	MSW	0.00	-17	0.00	-18	1.79	Rigamonti et al., GREET	2009, 1.8d
	Switchgrass	0.03	26	0.04	23	1.72	GREET	1.8d
	Woody	0.03	15	0.04	13	1.72	GREET	1.8d
Ethanol	Corn	0.04	-45	0.10	26	1.22	GREET	1.8d
	Corn stover	0.06	-58	0.12	14	1.79	GREET	1.8d
	Forest residues	0.07	-56	0.13	16	1.69	GREET	1.8d
	Sugarcane	0.08	-78	0.15	-5	3.31	GREET, Macedo et al.	1.8d
	Switchgrass	0.04	-54	0.11	17	1.88	GREET	1.8d
	Woody	0.05	-59	0.12	12	2.14	GREET	1.8d
F-T Distillate	Coal w/ CCS	0.02	23	0.02	90	-	GREET	1.8d
	Corn stover	0.04	-67	0.04	6	2.29	GREET	1.8d
	Forest residues	0.06	-67	0.05	6	2.16	GREET	1.8d
	MSW	0.05	1	-	-	1.19	GHGenius	3.19a
	Natural gas	0.02	19	0.02	86	-	GREET	1.8d
	Switchgrass	0.03	-63	0.03	9	2.41	GREET	1.8d
	Woody	0.03	-69	0.03	4	2.74	GREET	1.8d
Hydrogen - Gaseous	MSW	0.12	-6	-	-	1.19	GHGenius	3.19a
	100% renewable elec.	0.01	19	0.02	17	1.77	GREET	1.8d
	Average grid elec.	0.01	31	0.02	29	1.77	GREET	1.8d
	Coal w/ CCS	0.01	23	0.01	21	-	GREET, Spath et al.	1.8d, 2004
	Natural gas	0.01	83	0.01	76	-	GREET	1.8d
	Natural gas w/ CCS	0.01	30	0.01	28	-	GREET	1.8d
	Switchgrass	0.02	9	0.02	9	1.41	GREET	1.8d
	Switchgrass w/ CCS	0.02	-94	0.02	-86	1.41	GREET	1.8d
	Woody	0.02	5	0.02	4	1.41	GREET	1.8d
	Woody w/ CCS	0.02	-106	0.02	-97	1.41	GREET	1.8d
Hydrogen - Gaseous via EtOH	Corn	0.05	34	0.05	31	1.56	GREET	1.8d
	Corn stover	0.08	15	0.08	14	2.29	GREET	1.8d
	Forest residues	0.10	18	0.09	17	2.16	GREET	1.8d
Hydrogen - Liquid	100% renewable elec.	0.02	23	0.03	21	1.81	GREET	1.8d
	Average grid elec.	0.02	38	0.03	35	1.81	GREET	1.8d
	Coal w/ CCS	0.02	82	0.02	75	-	GREET, Spath et al.	1.8d, 2004
	Natural gas	0.01	112	0.01	102	-	GREET	1.8d
	Natural gas w/ CCS	0.01	57	0.01	52	-	GREET	1.8d
	Switchgrass	0.03	14	0.03	13	1.53	GREET	1.8d
	Switchgrass w/ CCS	0.03	-94	0.03	-86	1.53	GREET	1.8d
	Woody	0.04	7	0.03	6	1.53	GREET	1.8d
	Woody w/ CCS	0.04	-108	0.03	-99	1.53	GREET	1.8d
Hydrogen - Liquid via EtOH	Corn	0.06	40	0.05	37	1.56	GREET	1.8d
	Corn stover	0.09	22	0.08	20	2.29	GREET	1.8d
	Forest residues	0.10	25	0.09	23	2.16	GREET	1.8d
LNG	Natural gas	0.01	14	0.01	65	-	GREET	1.8d
PO - Diesel	Corn stover	0.08	-56	0.16	17	1.04	Hsu, GREET	2011, 1.8d
	Forest residues	0.09	-57	0.17	16	0.98	Hsu, GREET	2011, 1.8d
	Switchgrass	0.06	-52	0.14	21	1.10	Hsu, GREET	2011, 1.8d
	Woody	0.07	-58	0.15	15	1.25	Hsu, GREET	2011, 1.8d
PO - Gasoline	Corn stover	0.08	-56	0.13	14	1.04	Hsu, GREET	2011, 1.8d
	Forest residues	0.09	-57	0.14	13	0.98	Hsu, GREET	2011, 1.8d
	Switchgrass	0.06	-52	0.12	18	1.10	Hsu, GREET	2011, 1.8d
	Woody	0.07	-58	0.12	12	1.25	Hsu, GREET	2011, 1.8d
RD	Algae	0.01	-45	0.01	24	0.00	GHGenius, GREET	3.19a, 1.8d
	Palm	0.24	9	-	-	0.12	GHGenius	3.19a
RD - SuperCetane	Soybeans	0.04	-63	0.03	11	1.75	GREET	1.8d
RD - UOP-HDO	Soybeans	0.04	-61	0.04	12	1.39	GREET	1.8d
RG	Soybeans	0.04	-61	0.04	11	2.49	GREET	1.8d

Table B.2. Vehicle Fuel Efficiencies Used to Calculate WTW Life Cycle GHG Emissions and Petroleum Consumption Estimates

Fuel efficiencies taken from GREET Model Version 1.8d

Vehicle Type	Fleet Fuel Economy 2005	Fleet Fuel Economy 2020, 2050, 2050+	Fleet Fuel Economy 2005	Fleet Fuel Economy 2020, 2050, 2050+
N/A	*MJ_{fuel}/mile*	*MJ_{fuel}/mile*	*mile/ $gallon_{gasoline\ equivalent}$*	*mile/ $gallon_{gasoline\ equivalent}$*
Internal Combustion Engine	5.4	4.3	23	28
Compression Ignition Direct Injection	4.5	3.6	27	34
Flexible Fuel	5.4	4.3	23	28
Electric	1.8	1.3	68	93
Fuel Cell	1.8	1.8	68	69
Dedicated EtOH and BuOH	5.0	4.1	24	30
Dedicated CNG	5.7	4.3	22	29
Dedicated LNG	5.7	4.3	22	29

Table B.3. Lower Heating Value Assumptions from GREET for Liquid Fuels

Liquid Fuels:	Lower Heating Value
N/A	*Btu /gal_{fuel}*
Crude oil	129670
Conventional gasoline	116090
U.S. conventional diesel	128450
Ethanol	76330
Butanol	99837
Liquefied natural gas (LNG)	74720
Methyl ester (biodiesel, BD)	119550
Fischer-Tropsch diesel (FTD)	123670
Renewable Diesel I (SuperCetane)	117059
Renewable Diesel II (UOP-HDO)	122887
Renewable Gasoline	115983
Liquid hydrogen	30500
Natural gas liquids	83686

Table B.4. Lower Heating Value Assumptions for Solid Fuels

from GREET and Rigamonti et al. (2009)

Solid Fuels (Source):	Lower Heating Value
N/A	*mmBtu /$ton_{feedstock}$*
Corn (GREET)	15.01
Corn stover (GREET)	14.08
Farmed trees (GREET)	16.81
Forest residue (GREET)	13.24
Herbaceous biomass (GREET)	14.80
Soybeans (GREET)	17.68
Sugarcane (GREET)	12.95
MSW 2005 (Rigamonti et al. 2009)	9.71
MSW 2020/2050 (Rigamonti et al. 2009)	9.56
MSW 2050+ (Rigamonti et al. 2009)	9.85

Table B.5. Existing Fuel Pathway Parameter Modifications in GREET

GREET Model Year Parameters						
Parameters	*Original 2020 Value*	*2020 Value*	*2050 Value*	*2050+ Value*	*Unit*	*Source(s) if difference from original 2020 values*
For Each Scenario Year						
All Fuel Pathways						
Fraction of Generation from Biomass	2.0%	2.1%	15.2%	17.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Nuclear	20.6%	18.6%	8.0%	4.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Natural Gas	15.6%	8.3%	2.5%	1.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Oil	1.0%	0.2%	0.0%	0.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Coal	48.0%	43.4%	8.7%	5.0%	Fraction	REF 80% Renewable Scenario
Fraction of Other Generation from Wind	35.9%	48.1%	56.5%	56.8%	Fraction	REF 80% Renewable Scenario
Fraction of Other Generation from Solar	0.0%	5.5%	19.9%	19.9%	Fraction	REF 80% Renewable Scenario
Fraction of Other Generation from Geothermal	4.7%	15.2%	6.3%	6.2%	Fraction	REF 80% Renewable Scenario
Fraction of Other Generation from Hydropower	53.9%	31.3%	17.4%	17.1%	Fraction	REF 80% Renewable Scenario
Fraction of Other Generation from Other	5.5%	0.0%	0.0%	0.0%	Fraction	REF 80% Renewable Scenario
User Defined Life Cycle GHG Emission Intensity	N/A	485.2	113.3	91.4	g CO_2eq/kWh	Created in GREET for TEF
Use User Definied GHG Emission Intensity instead of GREET Calculated GHG Emission Intensity	N/A	1	1	1	On/Off Switch	Created in GREET for TEF
Petroleum Pathways						
Oil Sands Recovery Efficiency: Surface Mining	95%	95%	95%	96%	Fraction	Projection
Oil Sands Upgrading Efficiency: Surface Mining	99%	99%	99%	99%	Fraction	Projection
Oil Sands Recovery Efficiency: In-Situ Production	86%	86%	86%	89%	Fraction	Projection
Share of Surface Mining Process in Oil Sands Recovery	45%	45%	45%	27%	Fraction	Projection
Share of Oil Sands Products in Crude Oil Blend	18%	18%	18%	44%	Fraction	Projection
Natural Gas Pathways						
NA NG Liquefaction Efficiency	92%	92%	92%	95%	Fraction	Projection
NNA NG Liquefaction Efficiency	92%	92%	92%	95%	Fraction	Projection
NNA FG Liquefaction Efficiency	92%	92%	92%	95%	Fraction	Projection
Fischer-Tropsch Diesel Pathways						
FTD Production Efficiency: NA NG, no steam/kWh export	65%	65%	65%	71%	Fraction	Projection
FTD Production Efficiency: NA NG, with steam/kWh export	58%	58%	58%	64%	Fraction	Projection
FTD Production Efficiency: NNA NG, no steam/kWh export	65%	65%	65%	71%	Fraction	Projection
FTD Production Efficiency: NNA NG, with steam/kWh export	58%	58%	58%	64%	Fraction	Projection
FTD Production Efficiency: NNA FG, no steam/kWh export	65%	65%	65%	71%	Fraction	Projection
FTD Production Efficiency: NNA FG, with steam/kWh export	58%	58%	58%	64%	Fraction	Projection
Energy Efficiency of Biomass Gasification for FTD Production: no Steam/kWh Export (for woody crops)	50%	35%	43%	46%	Fraction	Mark Ruth, Assumed a 5% change for 2050+
Energy Efficiency of Biomass Gasification for FTD Production: no Steam/kWh Export (for herbaceous crops)	50%	39%	49%	52%	Fraction	Mark Ruth, Assumed a 5% change for 2050+
Energy Efficiency of Biomass Gasification for FTD Production: no Steam/kWh Export (for corn stover)	50%	41%	52%	54%	Fraction	Mark Ruth, Assumed a 5% change for 2050+
Energy Efficiency of Biomass Gasification for FTD Production: no Steam/kWh Export (for forest residues)	50%	44%	55%	58%	Fraction	Mark Ruth, Assumed a 5% change for 2050+
Coal-Based FTD Plant	233.3	233.3	233.3	42.4	kWh/ton C	Projection

Table B.5 continued

Hydrogen Pathways						
G.H2 Production Efficiency: NA NG, no steam/kWh export	73%	73%	73%	79%	Fraction	Projection
G.H2 Production Efficiency: NA NG, with steam/kWh export	71%	71%	71%	77%	Fraction	Projection
G.H2 Production Efficiency: NNA NG, no steam/kWh export	73%	73%	73%	79%	Fraction	Projection
G.H2 Production Efficiency: NNA NG, with steam/kWh export	71%	71%	71%	77%	Fraction	Projection
G.H2 Production Efficiency: NNA FG, no steam/kWh export	73%	73%	73%	79%	Fraction	Projection
G.H2 Production Efficiency: NNA FG, with steam/kWh export	71%	71%	71%	77%	Fraction	Projection
(Liquid) H2 Production Efficiency: NA NG, no steam/kWh export	73%	73%	73%	79%	Fraction	Projection
(Liquid) H2 Production Efficiency: NA NG, with steam/kWh export	71%	71%	71%	77%	Fraction	Projection
(Liquid) H2 Production Efficiency: NNA NG, no steam/kWh export	73%	73%	73%	79%	Fraction	Projection
(Liquid) H2 Production Efficiency: NNA NG, with steam/kWh export	71%	71%	71%	77%	Fraction	Projection
(Liquid) H2 Production Efficiency: NNA FG, no steam/kWh export	73%	73%	73%	79%	Fraction	Projection
(Liquid) H2 Production Efficiency: NNA FG, with steam/kWh export	71%	71%	71%	77%	Fraction	Projection
Energy Efficiency of Coal Gasification for G.H2 Production: no Steam/kWh Export	63%	63%	63%	69%	Fraction	Projection
Energy Efficiency of Biomass Gasification for G.H2 Production: no Steam/kWh Export	60%	60%	60%	78%	Fraction	Projection
Energy Efficiency of Coal Gasification for G.H2 Production: Steam/kWh Export	57%	57%	57%	68%	Fraction	Projection
Energy Efficiency of Biomass Gasification for G.H2 Production: Steam/kWh Export	57%	57%	57%	93%	Fraction	Projection
Energy Efficiency of Coal Gasification for (Liquid) H2 Production: no Steam/kWh Export	63%	63%	63%	69%	Fraction	Projection
Energy Efficiency of Biomass Gasification for (Liquid) H2 Production: no Steam/kWh Export	60%	60%	60%	78%	Fraction	Projection
Energy Efficiency of Coal Gasification for (Liquid) H2 Production: Steam/kWh Export	57%	57%	57%	68%	Fraction	Projection
Energy Efficiency of Biomass Gasification for (Liquid) H2 Production: Steam/kWh Export	57%	57%	57%	93%	Fraction	Projection
G.H2 Production Efficiency: NA NG	72%	72%	72%	78%	Fraction	Projection
G.H2 Production Efficiency: NNA NG	72%	72%	72%	78%	Fraction	Projection
G.H2 Production Efficiency: Electrolysis	74%	74%	74%	86%	Fraction	Projection
(Liquid) H2 Production Efficiency: NA NG	72%	72%	72%	78%	Fraction	Projection
(Liquid) H2 Production Efficiency: NNA NG	72%	72%	72%	78%	Fraction	Projection
(Liquid) H2 Production Efficiency: Electrolysis	74%	74%	74%	86%	Fraction	Projection
H2 Liquefaction Efficiency: Central Plant, NA NG	72%	72%	72%	75%	Fraction	Projection
H2 Liquefaction Efficiency: Central Plant, NNA NG	72%	72%	72%	75%	Fraction	Projection
H2 Liquefaction Efficiency: Central Plant, Coal	72%	72%	72%	75%	Fraction	Projection
H2 Liquefaction Efficiency: Central Plant, Biomass	72%	72%	72%	75%	Fraction	Projection
H2 Liquefaction Efficiency (Central, solar energy)	72%	72%	72%	75%	Fraction	Projection
H2 Liquefaction Efficiency: Station H2, NA NG	70%	70%	70%	76%	Fraction	Projection
H2 Liquefaction Efficiency: Station H2, NNA NG	70%	70%	70%	76%	Fraction	Projection
H2 Liquefaction Efficiency: Station H2, Electrolysis	70%	70%	70%	76%	Fraction	Projection
H2 Liquefaction Efficiency: Station H2, EtOH	70%	70%	70%	76%	Fraction	Projection

Table B.5 continued

Corn Ethanol Pathways						
Share of Dry Mill Corn EtOH Production Between Dry and Wet Corn EtOH Production	91.10%	91.10%	100.00%	100.00%	Fraction	Projection
Corn Farming Energy Use	6,893	6,893	6,893	2,161	Btu/bushel of corn	Projection
N Fertilizer Use for Corn Farming	327	327	327	229	N grams/bushel	Projection
P2O5 Fertilizer Use for Corn Farming	133	133	133	91	P2O5 grams/bushel	Projection
K2O Fertilizer Use for Corn Farming	149	149	149	104	K2O grams/bushel	Projection
CaCO3 Fertilizer Use for Corn Farming	1,357	1,357	1,357	945	CaCO3 grams/bushel	Projection
Corn Yield	174	174	174	222	bu/harvest acre	Projection
EtOH Yield of Corn EtOH Plant: Dry Mill	2.93	3.3	3.3	3.47	gal/bushel	Mark Ruth, Assumed a 5% change for 2050+
EtOH Yield of Corn EtOH Plant: Wet Mill	2.74	3.11	3.11	3.30	gal/bushel	Mark Ruth, Assumed a 5% change for 2050+
Corn EtOH Plant Energy Use: Dry Mill	28,908	28,908	28,908	28,105	Btu/gal	Projection
Share of Coal in Total Process Fuels of Corn Ethanol Plant: Dry Milling	8%	8%	8%	0%	Fraction	Projection
Shares of EtOH process fuels: Biomass	0%	0%	0%	50%	Fraction	Projection
Shares of EtOH biomass process fuels: Corn Stover	0%	0%	0%	100%	Fraction	Projection
Corn Butanol Pathways						
BuOH Yield	3.74	3.74	3.74	4.79	gallons per bushel of corn	Projection
Fossil use for BuOH fuel production	46,042	46,042	46,042	32,229	Btu/gallon	Projection
Electricity Demand for BuOH fuel production	0.70	0.70	0.70	0.49	kwh/gallon	Projection
Acetone Yield	4.66	4.66	4.66	5.97	gallons per bushel of corn	Projection
Fossil use for Acetone fuel production	36,926	36,926	36,926	25,848	Btu/gallon	Projection
Electricity Demand for Acetone fuel production	0.57	0.57	0.57	0.40	kwh/gallon	Projection
Cellulosic Butanol Pathways						
Ethanol yield: Farmed Trees (for butanol production)	90	32.4	47.9	50.3	gallons per dry ton	Mark Ruth, Assumed a 5% change for 2050+
Ethanol yield: H. Biomass (for butanol production)	90	32.4	47.9	50.3	gallons per dry ton	Mark Ruth, Assumed a 5% change for 2050+
Ethanol yield: Forest Residues (for butanol production)	90	32.4	47.9	50.3	gallons per dry ton	Mark Ruth, Assumed a 5% change for 2050+
Ethanol yield: Corn Stover (for butanol production)	90	32.4	47.9	50.3	gallons per dry ton	Mark Ruth, Assumed a 5% change for 2050+
Cellulosic Ethanol Pathways						
Farmed Trees Farming Energy Use	234,770	234,770	234,770	73,013	Btu/dry ton	Projection
N Fertilizer Use for Farmed Trees Farming	709	709	709	469	N grams/dry ton	Projection
P2O5 Fertilizer Use for Farmed Trees Farming	189	189	189	117	P2O5 grams/dry ton	Projection
K2O Fertilizer Use for Farmed Trees Farming	331	331	331	194	K2O grams/dry ton	Projection
EtOH Yield of Farmed Trees - Fermentation	90	79	98	103	gal/dry ton	Mark Ruth, Assumed a 5% change for 2050+
H. Biomass Farming Energy Use	217,230	217,230	217,230	67,558	Btu/dry ton	Projection
N Fertilizer Use for H. Biomass Farming	10,635	10,635	10,635	7,040	N grams/dry ton	Projection
P2O5 Fertilizer Use for H. Biomass Farming	142	142	142	88	P2O5 grams/dry ton	Projection
K2O Fertilizer Use for H. Biomass Farming	226	226	226	132	K2O grams/dry ton	Projection
EtOH Yield of H. Biomass - Fermentation	90	79	98	103	gal/dry ton	Mark Ruth, Assumed a 5% change for 2050+
Forest Residue Farming Energy Use	305,700	305,700	305,700	95,072	Btu/dry ton	Projection
EtOH Yield of Forest Residue - Fermentation	90	79	98	102.9	gal/dry ton	Mark Ruth, Assumed a 5% change for 2050+
Forest Residue Plant	Gasification	Fermentation	Fermentation	Fermentation	N/A	Assumption
EtOH Yield of Corn Stover - Fermentation	90	79	98	102.9	gal/dry ton	Mark Ruth, Assumed a 5% change for 2050+

Table B.5 continued

Sugarcane Ethanol Pathways						
Grams of Nitrogen	1,092	551	505	480	grams/wet tonne of Cane	Macedo et al. 2008, Assumed a 5% change for 2050+
Ethanol yield	24	22.8	24.4	25.6	gallons per wet tonne of sugarcane	Macedo et al. 2008, Assumed a 5% change for 2050+
Bagasse yield	0.28	0.1	0.4	0.42	wet tonne per wet tonne of sugar cane	Macedo et al. 2008, Assumed a 5% change for 2050+
Electricity credit	0	-0.4	-5.5	-5.8	kWh per gallon of ethanol	Macedo et al. 2008, Assumed a 5% change for 2050+
Oil Based Fuel Pathways						
Soy Oil Extraction Energy Use	3,551	3,551	3,551	3,428	Btu/lb of soyoil	Projection
Soybean use	5.4	2.59	2.59	2.461	lbs. soybean/lb soy oil	Mark Ruth, Assumed a 5% change for 2050+
Soyoil use: biodiesel	1.04	1.04	1.04	0.988	lbs. soy oil/lb.	Mark Ruth, Assumed a 5% change for 2050+
Soyoil use: renewable diesel 1	1.51	1.743	1.743	1.656	lbs. soy oil/lb.	Mark Ruth, Assumed a 5% change for 2050+
Soyoil use: renewable diesel 2	1.174	1.403	1.403	1.333	lbs. soy oil/lb.	Mark Ruth, Assumed a 5% change for 2050+
Soyoil use: renewable gasoline	2.231	2.4653	2.4653	2.342	lbs. soy oil/lb.	Mark Ruth, Assumed a 5% change for 2050+
Soyoil transesterification	1844	1844	1844	1291.12	Btu/lb. of biodiesel	Projection
Renewable Diesel 1 Production	1683	1683	1683	1178.10	Btu/lb. of renewable diesel	Projection
Renewable Diesel 2 Production	1851	1851	1851	1295.70	Btu/lb. of renewable diesel	Projection
Renewable Gasoline Production	186	186	186	129.92	Btu/lb. of renewable gasoline	Projection
Shares of process fuels: Soybeans to oil - natural gas	57.57%	57.57%	57.57%	85.91%	Fraction	Assumption
Shares of process fuels: Soybeans to oil - coal	28.34%	28.34%	28.34%	0.00%	Fraction	Assumption
Electricity Pathways						
Residual Oil-Fired Power Plants (Utility Boiler)	35%	35%	35%	36%	Fraction	Projection
Natural Gas-Fired Power Plants (Utility Boiler)	35%	35%	35%	36%	Fraction	Projection
Natural Gas-Fired Power Plants (Simple Cycle Gas Turbine)	34%	34%	34%	36%	Fraction	Projection
Natural Gas-Fired Power Plants (Combined Cycle Gas Turbine)	60%	60%	60%	90%	Fraction	Projection
Coal-Fired Power Plants (Utility Boiler)	34%	34%	34%	36%	Fraction	Projection
Coal-Fired Power Plants (Integrated Gasification Combined Cycle)	50%	50%	50%	68%	Fraction	Projection
Biomass-Fired Power Plants (Utility Boiler)	32%	32%	32%	34%	Fraction	Projection
Biomass-Fired Power Plants (Integrated Gasification Combined Cycle)	45%	45%	45%	57%	Fraction	Projection
NG CC Share of Total NG Power Plant Capacity	48%	48%	48%	60%	Fraction	Projection
NG Simple-Cylce Gas Turbine Share of Total NG Power Plant Capacity	38%	38%	38%	44%	Fraction	Projection
IGCC share of Total Coal Power Plant Capacity	3%	3%	3%	15%	Fraction	Projection
IGCC share of Total Biomass Power Plant Capacity	3%	3%	3%	15%	Fraction	Projection

Table B.6. New Fuel Pathway Parameter Modifications in GREET

GREET Model Fuel Pathway Specific Parameters						
Parameters	*Original Value*	*New Value*			*Unit*	*Source*
Cellulosic Pathways -----> Cellulosic Butanol Pathways						
Switch Cellulosic Ethanol to Butanol	0	1			Off/On Switch	Created in GREET for TEF
Increase in diesel consumption	N/A	63.40%			Fraction	Mullins et al. 2011
Coal Based Electricity or Biomass Pathways w/ CCS						
Use Landfill Gas Instead of NG for Electricity	0	1			Off/On Switch	Created in GREET for TEF
Coal Based Electricity or Biomass Pathways w/ CCS						
Use Coal w/ CCS	0	1			Off/On Switch	Created in GREET for TEF
Carbon Capture Rate	N/A	89%			Fraction	GREET 1.8d
Coal-Based Electricity w/ CCS Efficiency Loss	N/A	9.8%			Fraction	Spath and Mann 2004
Electricity and Hydrogen w/ 100% Renewable Electricity						
Fraction of Generation from Biomass	2.0%	19.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Generation from Nuclear	20.6%	0.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Generation from Natural Gas	15.6%	0.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Generation from Oil	1.0%	0.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Generation from Coal	48.0%	0.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Other Generation from Wind	35.9%	57.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Other Generation from Solar	0.0%	20.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Other Generation from Geothermal	4.7%	6.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Other Generation from Hydropower	53.9%	17.0%			Fraction	REF 80% Renewable Scenario (Projected)
Fraction of Other Generation from Other	5.5%	0.0%			Fraction	REF 80% Renewable Scenario (Projected)
User Defined Life Cycle GHG Emission Intensity	N/A	54.60			g CO_2eq/kWh	Created in GREET for TEF

Table B.7. Existing Fuel Pathway Parameter Modifications in the Pyrolysis Oil Model

Pyrolysis Model Fuel Pathway Specific Parameters						
Parameters	*Original Value*	*2020 Value*	*2050 Value*	*2050+ Value*	*Unit*	*Source*
Pyrolysis Diesel						
Yield: Farmed Trees	100	65	100	105	gal fuel/dry ton feedstock	Mark Ruth
Yield: H. Biomass	100	65	100	105	gal fuel/dry ton feedstock	Mark Ruth
Yield: Forest Residues	100	65	100	105	gal fuel/dry ton feedstock	Mark Ruth
Yield: Corn Stover	100	65	100	105	gal fuel/dry ton feedstock	Mark Ruth
Pyrolysis Gasoline						
Yield: Farmed Trees	105	65	100	105	gal fuel/dry ton feedstock	Mark Ruth
Yield: H. Biomass	105	65	100	105	gal fuel/dry ton feedstock	Mark Ruth
Yield: Forest Residues	105	65	100	105	gal fuel/dry ton feedstock	Mark Ruth
Yield: Corn Stover	105	65	100	105	gal fuel/dry ton feedstock	Mark Ruth

Table B.8. Existing Fuel Pathway Parameter Modifications in GHGenius

GHGenius Model Parameters						
Parameters	*Original 2020 Value*	*2020 Value*	*2050 Value*	*2050+ Value**	*Unit*	*Source(s)*
All Fuel Pathways						
All Fuel Pathways						
Fraction of Generation from Biomass	2.0%	2.1%	15.2%	17.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Nuclear	20.6%	18.6%	8.0%	4.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Natural Gas Boile	10.0%	8.2%	2.4%	0.9%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Natural Gas Turbi	10.0%	0.1%	0.1%	0.1%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Oil	1.0%	0.2%	0.0%	0.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Coal	48.0%	43.4%	8.7%	5.0%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Other Renewabl	4.6%	18.9%	54.3%	60.5%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Hydropower	6.9%	8.6%	11.4%	12.5%	Fraction	REF 80% Renewable Scenario
Fraction of Generation from Other Carbon	0.0%	0.0%	0.0%	0.0%	Fraction	REF 80% Renewable Scenario
User Defined Life Cycle GHG Emission Intensit	N/A	134778.7	31460.6	25388.9	g CO_2eq/GJ	REF 80% Renewable Scenario

*Default GHGenius 2050 scenario data was used

BuOH = butanol; CCS = carbon capture and storage; CNG = compressed natural gas; EtOH = ethanol; FTD = Fischer-Tropsch diesel; LNG = liquid natural; gas; MSW = municipal solid waste; SRWC = short rotation woody crops; UOP-HDO = UOP LLC's hydrodeoxygenation renewable diesel process

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