ON THE ROAD TO REPLACING OIL:

A WELL-TO-WHEELS STUDY EXPLORING ALTERNATIVE TRANSPORTATION FUELS AND VEHICLE SYSTEMS

by

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Prof. Gregory Bothun, Ph.D.

Growing concerns about the depletion of world oil supplies and the resulting consequences, as well as concerns about global climate change motivate us to find solutions to replace oil consumption while reducing greenhouse gas emissions. This study explores the performance of various alternative transportation fuels and vehicle systems to reduce consumption of oil and other fossil fuels as well as emissions of greenhouse gases and several harmful pollutants. This study focuses on the light-duty vehicle fleet (all vehicles less than 8,500 pounds) as this segment of the transport fleet accounts for the bulk of transportation oil consumption. To provide a means to objectively compare the energy and emission effects of various fuels and vehicle technologies, this study conducts what is known as a 'well-to-wheels' analysis of each of the full fuel/vehicle pathways considered in this study. That is, this study quantifies the energy use and emissions along the entire fuel pathway that are associated with each mile traveled by a vehicle fueled with a specific fuel.

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NOTATION

Acronyms and Abbreviations-

ANL	Argonne National Laboratory
ASPO	Association for the Study of Peak Oil
BEV	battery electric vehicle
CAIR	Clean Air Interstate Rule
CIA	United States Central Intelligence Agency
CIDI	compression-ignition direct-injection (engine)
CH_4	methane
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CTR	Center for Transportation Research (at ANL)
DOE	United States Department of Energy
EBAMM	Energy Resource Group Biofuels Analysis Meta-Model
E85	ethanol blend: 85% ethanol, 15% reformulated gasoline by volume
EIA	United States Energy Information Administration
EPA	United States Environmental Protection Agency
EtOH	ethanol
FC	fuel cell
FCV	fuel cell vehicle
FHWA	United States Department of Transportation, Federal Highway Administration
GM	General Motors
GH2	gaseous hydrogen
GHG(s)	greenhouse gas(es)
GREET	Greenhouse gases Regulated Emissions and Energy use in Transportation model
GWP	global warming potential (of greenhouse gases; 100-year time horizon)
H_2	hydrogen
HEV	hybrid-electric vehicle
HHV	higher heating value
HVDC	high voltage direct current (transmission lines)
ICE	internal combustion engine
ICEV	internal combustion engine vehicle
IEA	International Energy Agency

IGCC	integrated gasification combined cycle (power plant)
IPCC	Intergovernmental Panel on Climate Change
LH2	liquid hydrogen
LHV	lower heating value
Li ion	lithium ion (batteries)
LPG	liquefied petroleum gas
LSD	low-sulfur diesel (15-ppm sulfur)
MTBE	methyl tertiary butyl ether
NA	North American
NG	Natural gas
NiMH	nickel-metal hydride (batteries)
N-NA	Non-North American
N_2O	nitrous oxide
NO_x	oxides of nitrogen
NRC	National Research Council (of the National Academies of Science and Engineering)
NREL	National Renewable Energy Laboratory
O_2	Oxygen
OPEC	Organization of the Petroleum Exporting Countries
ORNL	Oak Ridge National Laboratory
PC	pulverized coal (power plant)
PEM	proton exchange membrane (fuel cell)
PHEV	plug-in hybrid electric vehicle
PM	particulate matter
PM10	particulate matter smaller than 10 microns in diameter
PtW	pump-to-wheels (vehicle fueling and operation stage)
RFG	reformulated-gasoline (30-ppm sulfur, EtOH oxygenate, 2.3% by weight)
S	sulfur
SI	spark-ignition
SO_x	oxides of sulfur
UC	University of California
U.S.	United States of America
USDA	United States Department of Agriculture
VMT	vehicle miles traveled
VOC(s)	volatile organic compounds

WtW	well-to-wheels (complete fuel/vehicle system pathway)
WtP	well-to-pump (feedstock and fuel production and transportation stage)

Units of Measure-

Bbbl	billion barrels (of oil)
Bbbl/y	billion barrels (of oil) per year
bbl	barrel(s) (of oil)
Btu	British thermal unit(s)
bu	bushel (of corn)
dt	dry ton (of biomass)
F	Fahrenheit
g	gram(s)
gal	gallon(s)
GW	gigawatts (1 GW = 10^9 watts)
GWh	gigawatt-hours (1 GW = 10^9 watt-hours)
in.	inch(es)
K	Kelvin
kV	kilovolt(s)
kWh	kilowatt-hours (1 kWh = 10^3 watt-hours)
lb(s)	pound(s)
m	meter(s)
mi	mile(s)
mmbbl/d	million barrels (of oil) per day
mmBtu	million British thermal units
MW	megawatts (1 MW = 10^6 watts)
ppm	parts per millions
psi	pounds per square inch
SCF	standard cubic foot

EXECUTIVE SUMMARY

The primary goal of this study is to determine the potential of various alternative transportation fuels and vehicle propulsion systems to reduce the consumption of petroleum-based fuels in the light-duty transportation sector.[1] This sector is the largest consumer of petroleum in the United States and is almost entirely reliant on petroleum-based fuels. Considering increases in global oil prices, concerns about the impending peak in world oil production and the ever increasing share of imported oil and associated consequences, it is crucial that the United States begin a transition towards alternative vehicles utilizing fuels derived from domestically available, and as much as possible, renewable energy sources. Other motivations included determining the ability of these alternative fuels and vehicles to reduce emissions of greenhouse gases (GHGs) and harmful pollutants. The light-duty transport sector is a large contributor to total United States greenhouse gas emissions, and amidst growing concern about global climate change, finding ways to reduce GHGs resulting from light-duty transport could prove equally as import as reducing petroleum use.

In light of these goals and motivations, this study seeks to evaluate the relative performance of different alternative fuels and vehicles in reducing our fossil and petroleum energy use, as well as emissions of GHGs and harmful pollutants. To provide an accurate and adequate evaluation of the energy and emission effects of various fuels and vehicle technologies, it is crucial to analyze the energy use and emissions associated with both the vehicle operation (or pump-to-wheels) stage, as well as upstream fuel production-related (or well-to-pump) stages. As such, this study conducts what is known as a 'well-to-wheels'

[1] The light-duty transport section includes all vehicles under 8,500 lbs. This includes personal and fleet vehicles including cars, minivans, sports-utility vehicles and light-duty trucks.

analysis of each of the full fuel/vehicle pathways considered in this study. That is, this study quantifies the energy use and emissions along the entire fuel pathway that are associated with each mile travel by a vehicle fueled with a specific fuel. To do so, this study utilizes the *G*reenhouse gases *R*egulated *E*missions and *E*nergy use in *T*ransportation spreadsheet model, referred to as GREET, which was developed by researchers at Argonne National Laboratory's Center for Transportation Research. All assumptions and results are relevant to the year 2025, as this time horizon was selected in order to allow several alternative technologies and fuels to develop and to allow the composition of the light-duty transport fleet to change.

This study determines relevant assumptions related to both the upstream fuel production stages and vehicle fueling and operation and generates results for a total of 70 well-to-pump fuel production pathways, 15 vehicle propulsion systems and several dozen full well-to-wheels pathways. Fuels considered by this study include reformulated gasoline (RFG), low-sulfur diesel, compressed natural gas, liquefied petroleum gas, ethanol (from both corn and cellulosic biomass feedstocks), hydrogen (from both steam methane reforming of natural gas and electrolysis of water) as well as electricity as a direct vehicle fuel for battery electric and plug-in hybrid-electric vehicles. Vehicle propulsion systems considered include: spark-ignition (SI) and compression-ignition direct-injection internal combustion engine vehicles (ICEVs) fueled with a variety of fuels; hybrid electric vehicles (HEVs); hydrogen fuel cell vehicles (FCVs); battery electric vehicles; and plug-in hybrid electric vehicle (PHEV) versions of most of the other vehicle systems. Each of these alternative vehicles was modeled to represent a vehicle equivalent in size and performance to a baseline 22-mile-per-gallon spark-ignition internal combustion engine vehicle fueled with reformulated gasoline. This baseline vehicle is meant to be representative of the average size, weight and fuel economy of the light-duty vehicle sector in 2025 under a business-as-usual scenario.

This study finds that all alternative fuels and vehicles considered offer reductions in petroleum energy consumption relative to the baseline vehicle (see Figure ES-1). Alternative petroleum-based pathways, including diesel and hybrid-electric vehicles, achieve moderate reductions between 15-35%, almost entirely as a result of increased vehicle fuel economy. Natural gas and electricity-based pathways nearly eliminate petroleum energy use, although in many cases, these pathways simply substitute other fossil-derived energy for petroleum

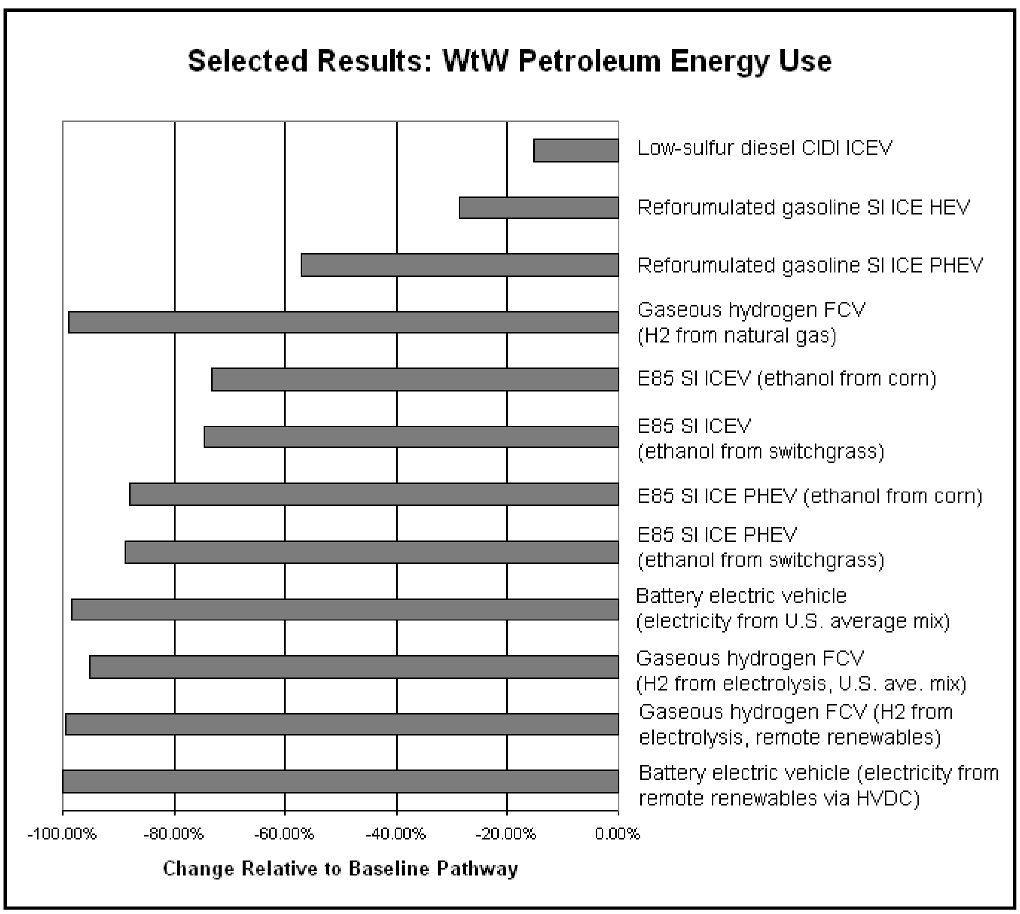

Figure ES-1: Selected Results – Well-to-Wheels Petroleum Energy Use

energy inputs. Biomass-based pathways including ethanol from corn and cellulosic biomass offer petroleum energy use approximately three-quarters less than the baseline pathway as they rely largely on biomass as a feedstock. The remaining petroleum energy use is due to the fact that this study considers ethanol in E85 blends (85% ethanol and 15% RFG by volume) and RFG makes up 21% of E85 by energy content.

In addition to offering petroleum energy reductions, several pathways considered also result in significant reductions in well-to-wheels fossil energy inputs as well (see Figure ES-2). As would be expected, pathways that rely primarily on renewable energy inputs including ethanol from cellulosic biomass and electricity or hydrogen derived from renewable energy offer the lowest fossil energy use. Several other pathways also result in significant reductions in fossil energy use between 25-65%, however, due to the overall WtW efficiency of these pathways. These include the hydrogen-from-natural gas pathways as well as the battery electric vehicle pathways and most plug-in hybrid-electric vehicles fueled with electricity from the U.S. generating mix. Additionally, the ethanol-from-corn pathway results in fossil energy use nearly 35% lower than the baseline due to the use of corn as a feedstock, although this reduction is significantly less than the reductions achieved by cellulosic ethanol pathways. This is due to the fact that ethanol production from corn relies on significant inputs of coal and natural gas for process energy, while production of ethanol from cellulosic biomass utilizes the lignin portion of the biomass feedstock to provide all of the necessary process energy (as well as to generate significant quantities of electricity for export).

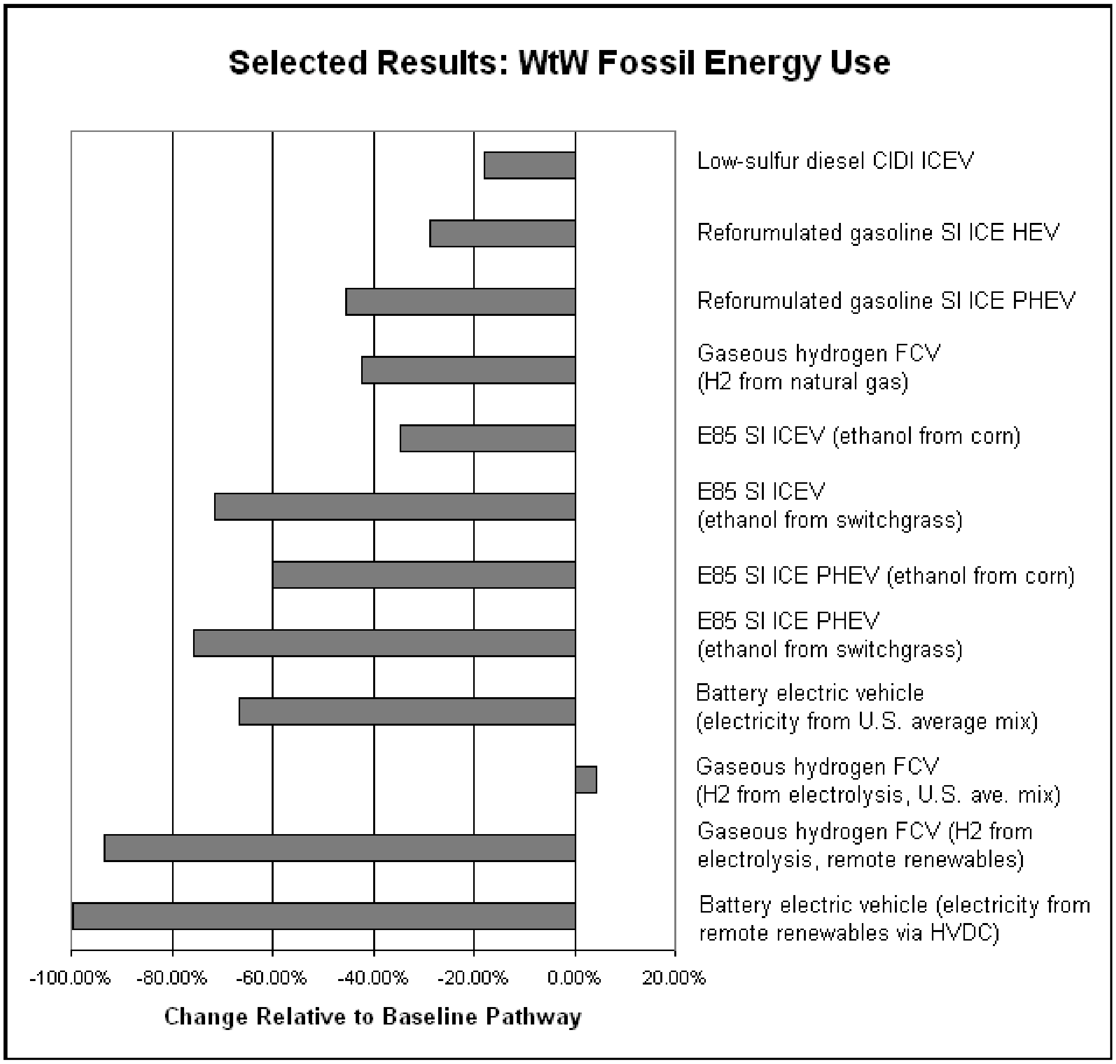

Figure ES-2: Selected Results – Well-to-Wheels Fossil Energy Use

Despite the fact that many pathways result in significant petroleum energy use reductions, several of these pathways (i.e., natural gas and electricity-based pathways) achieve these reductions by substituting other non-renewable, fossil fuel-derived energy inputs. In some cases, particularly those reliant on natural gas, this may mean that these pathways offer fewer benefits than indicated by the petroleum energy use reductions they achieve, as natural gas is also subject to resource depletion and related concerns. Natural gas supplies in North America are already tight and any increased reliance on natural gas for transportation fuels could simply displace concerns about imported oil onto concerns about imported natural gas, much of which is located in unstable areas of the world. When possible, fuel/vehicle pathways that offer reductions in fossil energy and/or rely on domestically produced energy resources should be preferred. This points to the importance of examining fossil energy use in addition to petroleum energy use.

In addition to energy use, this study presents results for the three main GHGs: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). The GHG emissions reductions achieved by the various fuel/vehicle pathways are roughly correlated with fossil energy reductions. Nearly all of the pathways considered by this study offer some reduction in GHG emissions (see Figure ES-3). As with fossil energy reductions, the pathways that offer the most significant reductions in GHG emissions are those that rely on renewable energy inputs. The pathways utilizing remote stranded renewables, for example, nearly eliminate GHG emissions, while the biomass-based E85 pathways offer GHG reductions between 72-83%. The remaining GHG emissions for these E85 pathways result from the combustion of the RFG contained in E85 blends.

This study finds that several other pathways that rely on feedstocks containing carbon also achieve GHG reductions, however, primarily as a result of high overall WtP efficiencies and/or low vehicle fuel consumption. These pathways include the hydrogen-from-natural gas pathways and the various PHEV and BEV pathways fueled with electricity from the U.S. generating mix, as well as corn-based E85, CNG, LPG, diesel and the two petroleum-fueled hybrid-electric vehicles (HEVs). These pathways offer GHG emissions reductions between 10-50% relative to the baseline vehicle. Finally, in contrast to all of the other pathways considered, this study finds that the electrolytic hydrogen pathways result in significant

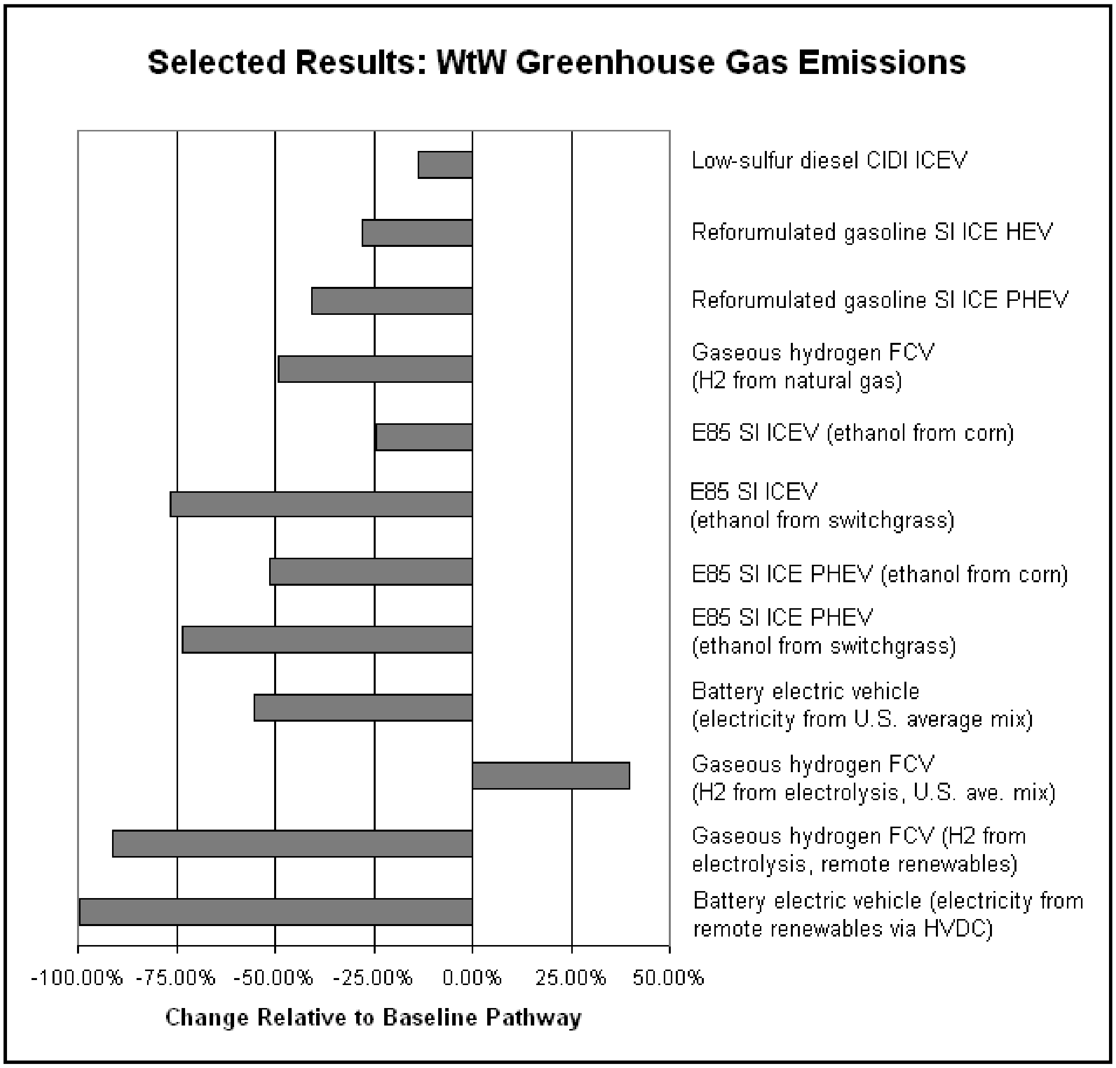

Figure ES-3: Selected Results – Well-to-Wheels Greenhouse Gas Emissions

increases in GHG emissions of approximately 40-80%, despite the fact that hydrogen itself is a carbon-free fuel and hydrogen fuel cell vehicles result in zero emissions of GHGs during vehicle operation. These increases are due to the GHG-intensive nature of the current coal-dominated U.S. electricity mix and the low WtP efficiency of electrolytic hydrogen production.

In addition to GHG emissions, this study presents results for well-to-wheels emissions of five criteria pollutants including: volatile organic compounds (VOCs); carbon monoxide (CO); oxides of nitrogen (NO_x); particulate matter (PM10); and oxides of sulfur (SO_x). This study indicates that, in general, alternative transportation fuels and vehicle propulsion systems help reduce criteria pollutant emissions associated with the light-duty transport sector. In particular, all but one of the alternative pathways results in some decrease in urban emissions of the five criteria pollutants (with the exception being urban NO_x emissions from the low-sulfur diesel pathway). However, several pathways result in increased total emissions of one or more criteria pollutants. The electricity-based pathways result in increased PM10 and SO_x emissions, for example. Additionally, the ethanol from farmed crops pathways result in increased emissions of NO_x and in the case of corn ethanol, a large increase in total PM10 emissions, both due to farming activities. The criteria pollutant results thus point to the fact that trade-offs may be necessary, as several pathways that perform well in all other metrics result in increases in total emissions of one or more criteria pollutants.

Considering this study's primary motivations, the well-to-wheels results generated by this study provide cause to be optimistic. This study demonstrates that there are several potential alternative vehicle fuels and propulsion systems that can significantly decrease petroleum energy use. The results also indicate that there are several promising options to drastically reduce GHG emissions related to the light-duty transport sector as well as emissions of several criteria pollutants. Care must be taken, however, to avoid simply substituting non-North American natural gas for petroleum use, lest the United States end up embroiled again in the negative consequences arising from reliance on a depleting energy source. Alterative fuels that rely on domestic energy sources should be preferred and renewable resources should be utilized as much as possible.

Some of the technologies and fuels analyzed in this study are ready and available today to contribute immediately to reducing petroleum and fossil energy use as well as emissions of GHGs and criteria pollutants. Other technologies still have unresolved technological, cost, infrastructure or other hurdles and may require additional research and financial support to reach the market quickly enough to take full advantage of their potential benefits in the timeframe considered by this study (i.e., by 2025). The results presented in this study can be used as an initial indication as to which technologies should receive the most concerted effort to bring to market. Plug-in hybrid electric vehicles, ethanol derived from woody and herbaceous biomass (i.e., cellulosic ethanol) and electric vehicles all offer a particularly good range of benefits. The pathways utilizing remote stranded renewables offer by far the best benefits, performing well in all the metrics, although developing these resources would require large capital investments and considerable planning.

In short, this study finds that the technical options are available to allow significant reductions in petroleum and fossil energy use as well as emissions of GHGs and criteria pollutants related to the light-duty transport sector. What is needed is the development of forward thinking strategies and actions to begin a concerted and rapid transition away from the current oil-addicted light-duty transport sector towards the use of vehicles fueled with energy derived from domestically available and, as much as possible, renewable energy sources. Such vehicles and fuels could also offer dramatically reduced emissions of GHGs and pollutants. This study indicates that the requisite options are available. We must now chart the road forward.

1. INTRODUCTION

1.1 Motivations

"Oil is the lifeblood of America's economy," touts the United States Department of Energy (DOE).[2] With oil making up 40% of our total energy consumption[3] and over 96% of the energy used for transportation[4], it is hard to argue with the DOE's sentiment. The United States consumed over 20 million barrels of oil every day (mmbbl/d) in 2004[5] and our level of consumption is continuing to rise.[6] These vast quantities of oil carry our workers to industries and businesses, our customers to stores, restaurants and services, even the very food we eat to our local grocery and back to our homes. It is the basic feedstock for the plethora of petroleum-based products that we use every day, it heats many of our homes and businesses and it even powers a portion of the electricity we use.[7] If the flow of oil were to stop, so to would the flow of goods and services, products and foodstuffs that make up our nation's economy. It is not a stretch then to say, as President George W. Bush declared in his 2006 State of the Union Address, "America is addicted to oil."[8]

But is this addiction safe? Is it without consequence? Can we Americans continue to count on an endless and ever increasing supply of oil to keep our economy flowing? These

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[2] United States Department of Energy. "Oil". *Energy*. <http://www.energy.gov/engine/content.do?BT_CODE=OIL>. Accessed 11/20/2005.

[3] Total energy consumption includes electricity, heating and transportation. ibid.

[4] Davis, Stacey C. and Susan W. Diegel. *Transportation Energy Data Book: Edition 24*. (Oak Ridge, TN: Oak Ridge National Laboratory, December 2004). p. 1-1.

[5] Actual figure is 20.74 mmbbl/d. Energy Information Administration. *Annual Energy Outlook 2006: With Projections to 2030*. (Washington D.C.: Energy Information Administration, Feb. 2006). p. 151, Table A11. This publication is referred to throughout this study as *AEO2006*.

[6] ibid. p. 151, Table A11.

[7] Petroleum-fired power plants made up just over 3% of total US electricity generation in 2004. See ibid. p. 147, Table A8.

[8] Office of the President of the United States of America. "2006 State of the Union". *The White House*. <http://www.whitehouse.gov/stateoftheunion/2006/>. Accessed 4/22/06.

are the questions that we must ask, considering the importance of oil to our economy and way of life. The answer to each of these crucial questions, however, seems to be a clear 'no'.

Oil is a finite resource and as such can never be counted on to last forever, especially in the face of increasing demand from the United States and the world. Increasing evidence is mounting that the so-called 'peak' of world oil production – the point where new production cannot offset depleting production at mature oil fields, resulting in a continual and inexorable decrease in world production – has either already happened or will happen within the next five or ten years. Geophysicist M. King Hubbert, who in 1956 successfully predicted the peak of U.S. oil production – it occurred in 1971, just one year later than his predictions – also predicted that the worldwide peak would occur between 1995 and 2000.[9] His estimate did not take into account the two OPEC oil shocks of the 1970s, however, and the resulting decreases in worldwide demand. The Association for the Study of Peak Oil (ASPO) revised Hubbert's prediction and now claims that worldwide production of conventional oil peaked in Spring of 2004 and predicts that total worldwide production (including unconventional sources of oil like oil sands and deepwater deposits) will peak sometime around 2010 (Figure 1-1).[10] Official U.S. DOE estimates, which have been criticized by scholars as too optimistic,[11] lie on the other side of the spectrum. Estimates

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[9] Hubbert, M. King. *Nuclear Energy and Fossil Fuels*. (Houston, TX: Shell Development Company, June 1956).

[10] Aleklett, K. and Campbell, C.J. "The Peak and Decline of World Oil and Gas Production." *Minerals & Energy* 18 (2003): 15-20.

[11] Critics point out, for example, that the government estimates accept at face value the reserve figures provided by OPEC countries. However, OPEC countries have a strong incentive to overestimate their reserves in order to boost their production quotas (which are tied to reserves). Reuters News Agency reported on January 20th, 2006, for example, that "Kuwait's oil reserves are only half those officially stated." See Reuters. "Kuwait oil reserves only half official estimate – PIW". *Reuters*. 1/20/06. <http://today.reuters.com/business/newsarticle.aspx?type=tnBusinessNews&storyID=nL20548125&imageid=&cap=>. Accessed 4/22/06.

from the DOE's Energy Information Administration (EIA), for example, project that the peak will not occur until sometime around 2030.[12]

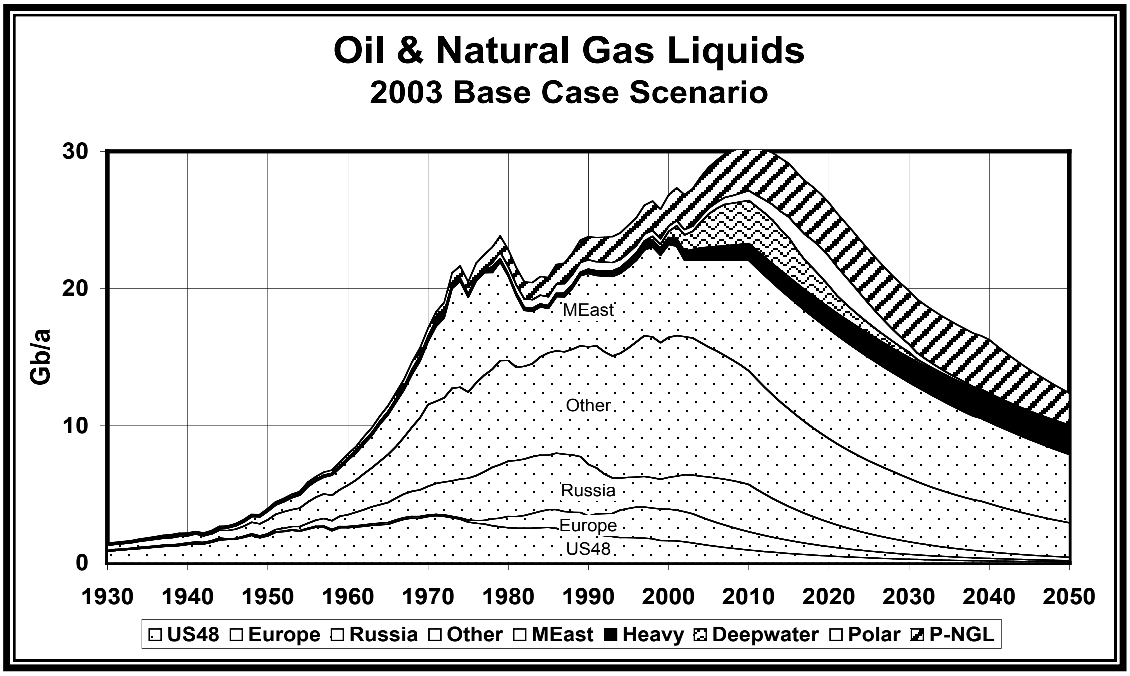

Figure 1-1: ASPO World Oil Production ('Peak Oil') Chart[13]

Some of the predicted peak oil dates have come and gone, while others still lie in the future. However, as Dr. Roger Bezdek, the coauthor of another peak oil study known as the 'Hirsch Report',[14] points out, while some critics have accused those who have made peak oil predictions of crying wolf, "wrong is not wrong forever … The message of that parable is

[12] The EIA does not explicitly predict when the peak will occur. This is my projection based on the EIA's published figures for total world oil reserves and production rates and is based on a simple 'bell-shaped' depletion curve. The equation for such a curve is: T = 1/k*LN(Rk/r+1) where T = total depletion time (note: the peak time = 1/2T), k = the rate of growth in production/consumption, R = total reserves, and r = initial production/consumption. The EIA optimistically estimates total world reserves (R) at 2,946.8 billion barrels (Bbbl), total world production in 2002 (r) at 28.5 Bbbl/y and the annual growth rate of production (k) at 2.09%/year. These figures yield a total depletion time of just over 55 years and the projected peak midway through 2029 (i.e., 2002 + 1/2*55). See EIA. *International Energy Outlook 2005.* (Washington D.C.: EIA, July. 2005).
[13] Aleklett and Campbell (2003), p. 13.
[14] Hirsch, Robert L. et al. *Peaking of World Oil Production: Impacts, Mitigation, and Risk Management.* (DOE National Energy Technology Laboratory, Feb. 2005).

that people were eventually eaten by the wolf."[15] The question of peak oil is not a matter of if, but when, and the answer is almost certainly soon.

Furthermore, while the United States continues to demand more and more oil and the world's production approaches its peak, we will not be the only country with a taste for crude. While the United States currently consumes about a quarter of the entire world's production of oil, our piece of the pie is shrinking.[16] The consumption rates of developing nations – notably China and India – are growing at twice the rate of the United States and other developed nations.[17] Increasing demand and tightening supplies will likely lead to higher oil prices, economic recessions and increased geopolitical conflict.

Our current levels of consumption are not without their costs either. As mentioned above, the United States' production of oil peaked in 1971 and has fallen steadily ever since. Meanwhile, our demand has continued to rise. The ever-growing gap between U.S. demand and U.S. production – now nearly 13 mmbbl/d[18] – has been filled by an increasing reliance on foreign sources of oil. Not only does this reliance on foreign oil mean that increasing amounts of U.S. currency are making their way abroad, contributing to the bulk of our trade deficit, but this dependence leaves our economy largely at the mercy of a foreign oil cartel: the Organization of Petroleum Exporting Countries (OPEC).[19] A study by the Oak Ridge National Laboratory[20] (ORNL) reports that the oil market upheavals caused by the OPEC cartel over the past three decades have cost the United States in the vicinity of $7 trillion

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[15] Quoted in Stantiford, Stuart. "ASPO-USA Denver Conference Report." *The Oil Drum*. Nov. 12, 2005. <http://www.theoildrum.com/story/2005/11/12/0150/4833>. Accessed 11/20/2005.
[16] Davis and Diegel, p. 1-5.
[17] ibid. p. 1-5.
[18] ibid. p. 1-1. In 2003, the U.S. consumed 20.04 mmbbl/d and produced only 7.46 mmbbl/d for net imports of 12.58 mmbbl/d.
[19] OPEC member states: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[20] Greene, D. and N. Tishchishyna, *The costs of oil dependence: a 2000 update*. (ORNL, May 2000).

(adjusted to 1998 dollars) in total economic costs.[21] This is, incidentally, about as large as the sum total of payments on the national debt over the same period. Furthermore, estimates of military expenditures to defend U.S. oil interests in the Middle East range from $6 to $60 billion per year[22] with a recent study by the National Defense Council Foundation putting the price tag at $49 billion per year for the defense of Middle Eastern oil.[23] This estimate does not include the costs of the latest Iraq War and occupation.

There are significant environmental costs to our dependence on oil as well. Criteria pollutants[24] spewed from vehicle tailpipes pollute our urban centers. These include: acid rain and smog forming nitrous oxides (NO_x); haze and acid rain inducing sulfur dioxide (SO_2); particulate matter (PM), which is damaging to the respiratory system and is another contributor to haze; volatile organic compounds (VOCs), which also contribute to the formation of ozone and smog; as well as poisonous carbon monoxide gas (CO). Furthermore, growing concerns about global climate change call attention to the massive quantities of carbon dioxide (CO_2) and other greenhouse gases (GHGs) emitted each year from U.S. vehicles. Consumption of oil for transportation needs accounts for nearly one third of all U.S. CO_2 emissions, amounting to nearly 1.9 billion metric tons of CO_2 in 2004.[25]

Clearly, there are a number of different but interconnected motivations that impel us to break our addiction to oil, particularly from foreign sources. These include (a) concerns about peak oil, (b) worries about the strategic and economic costs of our growing dependence

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[21] Greene and Tishchishyna quoted in Davis and Diegel, p. 1-10.
[22] Davis and Diegel, p. 1-11.
[23] Copulas, Milton R. *America's Achilles Heel – The Hidden Costs of Imported Oil*. (Washington D.C.: National Defense Council Foundation, Oct. 2003). Quoted in Davis and Diegel, p. 1-11.
[24] Criteria pollutants are those regulated by the United States Environmental Protection Agency (EPA) as mandated by the National Ambient Air Quality Standards. See EPA "National Ambient Air Quality Standards (NAAQS)". *Air and Radiation*. 3/1/06. <http://www.epa.gov/air/criteria.html>. Accessed 4/22/06.
[25] EIA 2006, p 160, Table A18.

on foreign oil, and (c) a desire to cut back criteria pollutants and (d) combat global climate change. These four major concerns provide the central motivation for this study.

1.2 Overview

Transportation accounts for two-thirds of total U.S. petroleum consumption.[26] Transport needs alone far outweigh our domestic production of oil, with nearly 13.7 mmbbl/d consumed for transport in the U.S. in 2004 while domestic production was just under half that at 7.23 mmbbl/d.[27] And if our economy is addicted to oil, our transportation sector is the worst 'junkie,' with over 96.4% of our transportation energy coming from oil.[28] Thus, no attempt to break our dependency on oil can succeed unless we find a way to wean our transportation sector off of petroleum, and so we must ask: are there viable alternatives that could transform our oil-guzzling transport fleet into something new, something cleaner, more renewable, domestically-fueled and even CO2-free?

This study seeks to begin to address that question. The aim of this study is to explore potential alternative transportation fuels and energy sources that can replace, in part or in full, the use of oil for the transport sector. This study focuses on fuels and technologies for the light-duty transportation fleet – i.e., vehicles weighing less than 8,500 pounds, which includes cars, minivans, sports-utility vehicles and light-trucks. The light-duty sector includes our personal vehicles as well as many of the vehicles maintained by commercial and governmental fleets. Light-duty vehicles account for the majority of energy consumption in

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[26] EIA *AEO2006* p. 152, Table A11.
[27] ibid. p. 152, Table A11. Domestic petroleum production includes crude oil and natural gas plant liquids.
[28] Davis and Diegel, p. 2-1. Figure is for 2003.

the U.S. transportation sector[29] and are thus a logical place to begin looking for alternatives to oil use.

In light of the four primary motivations described in Section 1.1 above, this study seeks to evaluate the relative performance of different fuel options in reducing our fossil and petroleum energy use, as well as emissions of GHGes and criteria pollutant. To provide an accurate and adequate evaluation of the energy and emission effects of various fuels and vehicle technologies, it is important to consider emissions and energy use from upstream fuel production processes as well as from vehicle operations. This is especially important for fuels with distinctly different primary energy sources (feedstocks) and fuel production processes, for which upstream emissions and energy use can be significantly different. Additionally some of the fuel options and vehicle technologies considered in this study, including hydrogen fuel cell and battery electric vehicles, result in zero vehicle 'tailpipe' emissions, while upstream energy use and emissions associated with producing and distributing these fuels can be considerable. These and other similar concerns make an objective comparison of different transportation fuels and vehicle technologies difficult unless the *entire* fuel pathway from feedstock recovery or production through the use of the fuel at the vehicle itself is considered.[30] As such, this study performs what has become known as a 'well-to-wheels' (WtW) analysis, after the traditional petroleum fuel pathway, which begins at an oil *well* and ends at the *wheels* of a gasoline-powered vehicle. That is,

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[29] ibid. p. 2-1. Figure is 56.6% and is for 2002.
[30] Note: it may also be important to consider the energy use, emissions and materials costs associated with the life-cycle of the vehicle, i.e., from production to disposal of the vehicle. When such an analysis is paired with a well-to-wheels fuel cycle analysis, it is known as a full 'life-cycle analysis' or 'cradle-to-grave' study. While analyzing the life-cycles of the various vehicle systems examined in this study is beyond the scope of the study, it could be extended by a future research effort in order to construct a full life-cycle analysis of the various fuel pathways and vehicle systems. For an example of a full life-cycle analysis, see Weiss, Malcom A. et al. *On the Road in 2020: A Life-cycle Analysis of New Automobile Technologies*. (Cambridge, MA: MIT Energy Laboratory, Oct. 2000).

this study quantifies the energy use and emissions along the entire fuel pathway that are associated with each vehicle mile traveled. This study utilizes the *G*reenhouse gases *R*egulated *E*missions and *E*nergy use in *T*ransportation spreadsheet model, referred to as GREET, to perform its well-to-wheels analysis. The GREET model, developed by Argonne National Laboratory, is discussed in Section 2.

A WtW analysis is often broken up into two main components (see Figure 1-2). The fuel production and distribution or 'well-to-pump' (WtP) portion encompasses every stage from feedstock production or recovery and transportation to fuel production on through distribution of the fuel at the 'pumps' of fueling stations.[31] The vehicle operation portion includes the fueling and operation of the vehicle and is referred to as the 'pump-to-wheels' (PtW) stage.

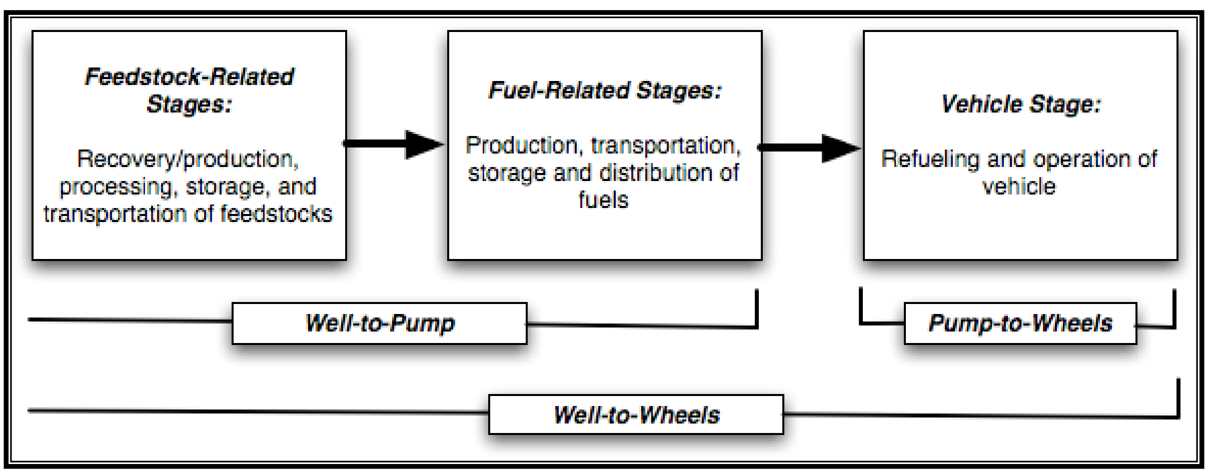

Figure 1-2: Scope of a Well-to-Wheels Analysis For Fuel/Vehicle Pathways

[31] Note: the feedstock and fuel production, transportation and distribution pathway is often referred to as the 'well-to-tank' portion of the WtW pathway. However, this is a misnomer in most cases as most of the literature, including this study, includes emissions and losses associated with vehicle fueling in the vehicle fueling and operation portion of the pathway. Thus, the 'well-to-tank' portion is more accurately called the 'well-to-pump' portion, as is done in this study, as it properly ends at the fueling station, or the gasoline pumps in the traditional petroleum to gasoline fuel pathway.

This study analyses the WtP fuel production pathways for several transportation fuels, as well as several vehicle types that utilize those fuels. The WtP fuel pathways fall into four main categories based on feedstock as follows: petroleum, natural gas, biomass, and electricity (see Figure 1-3). The WtP fuel production pathways considered in this study are discussed in detail in Section 3.

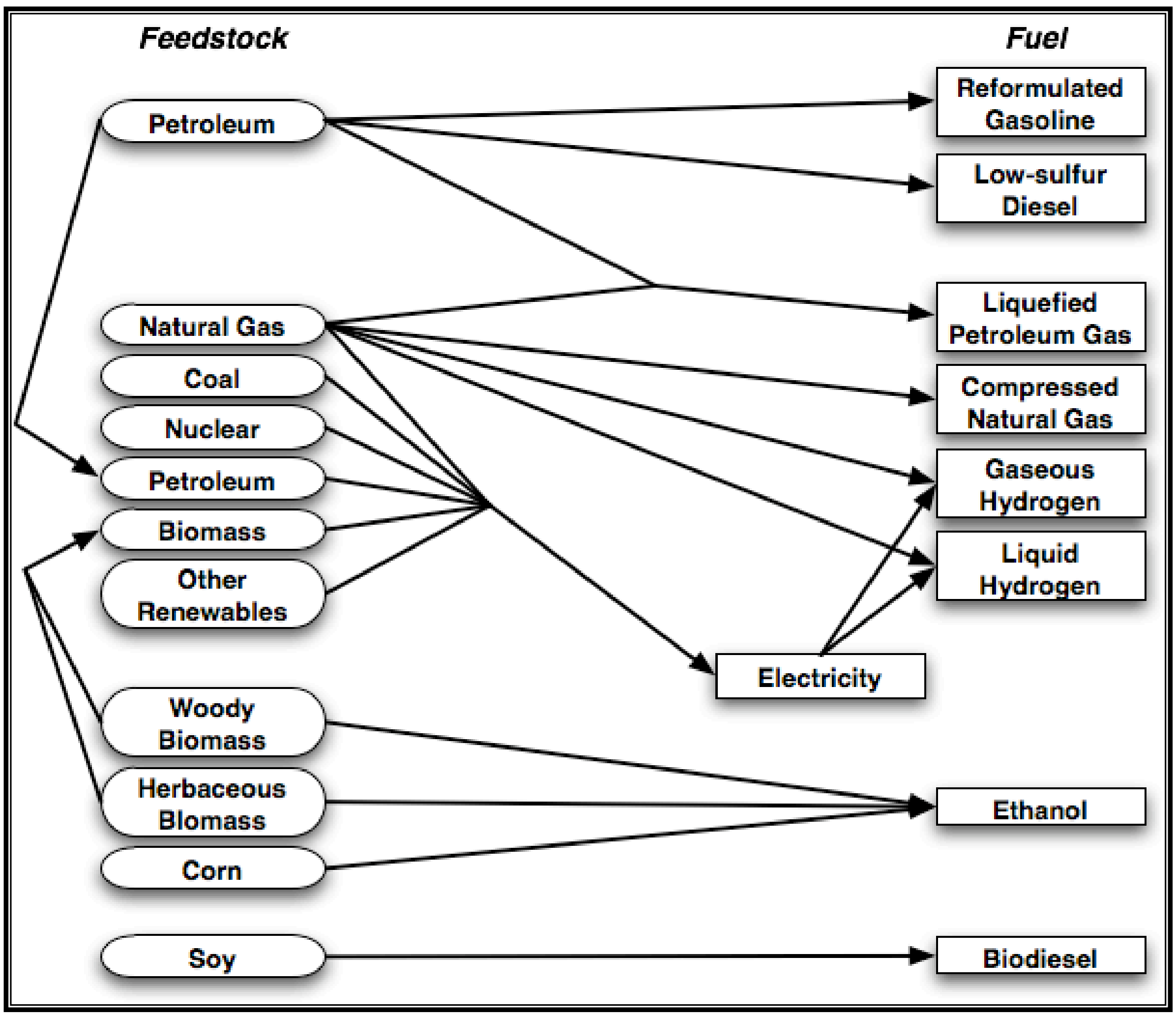

Figure 1-3: Energy Feedstocks and Fuels Examined in this Study

The PtW vehicle systems fall into five main categories, this time based on the fuel type: petroleum-based fuels, natural gas-based fuels, hydrogen, biofuels, and electricity (see

Table 1-1). These vehicle systems are presented in Section 4. When combined, the different WtP and PtW pathways yield several dozen complete WtW fuel cycles that can be compared in an objective manner. The results of the complete WtW fuel cycles analyzed by this study are presented in Section 5. Overall conclusions are presented in Section 6.

Table 1-1: Fuels and Vehicle Systems Examined in this Study

Fuel	*Vehicle Systems*
Reformulated gasoline	Spark-ignition (SI) gasoline internal combustion engine vehicle (ICEV); SI gasoline internal combustion engine (ICE) hybrid-electric vehicle (HEV); SI gasoline ICE plug-in hybrid-electric vehicle (PHEV)
Low-sulfur diesel	Compression-ignition direct-injection (CIDI) diesel ICEV; CIDI diesel ICE HEV; CIDI diesel ICE PHEV
Liquefied petroleum gas	SI liquefied petroleum gas ICEV
Compressed natural gas	SI compressed natural gas ICEV
Gaseous hydrogen	Gaseous hydrogen fuel cell vehicle (FCV); Gaseous hydrogen fuel cell (FC) PHEV
Liquid hydrogen	Liquid hydrogen FCV; Liquid hydrogen FC PHEV
Electricity	Battery electric vehicle (BEV); Plug-in hybrid vehicles (listed with other fuels)
Ethanol (E85)	SI E85 ICEV; SI E85 ICE PHEV

Some studies examining alternative transportation fuels focus on only one energy metric – i.e. 'net-energy-ratio'. That is, they focus on whether or not the production of the alternative fuel results in the use of more non-renewable energy than is contained in the resulting fuel. For example, much of the public debate over the merits of corn ethanol has focused on determining the net-energy-ratio of ethanol from corn (see Section 3.3). A number of WtW or life-cycle studies have been performed in the past two decades that attempt to determine of corn ethanol has a positive net-energy ratio, and the results have varied. Some – particularly professors, Ted Patzek of Cornell University and David Pimentel of University of California, Berkeley[32] – have concluded that corn ethanol requires more energy to produce than it yields, while (multiple) others have concluded that corn ethanol has a moderately positive net energy balance.

The debate over the net-energy ratio of corn ethanol aside, focusing solely on net-energy ratio can result in misleading results, particularly when the metric is considered 'in a vacuum' and not compared to the fuel that the alternative fuel is likely to replace – i.e. gasoline. In particular, a net energy metric ignores the fact that not all fossil fuels 'are created equal' – that is, there are vast differences in the energy, environmental, and policy implications of the use of various fossil fuels (coal, petroleum and natural gas) that a simple net energy metric ignores. Furthermore, a net energy ratio does not provide a sufficient environmental metric either, as it is not an accurate indicator of emissions of GHGs or criteria pollutants, or of other environmental factors including soil erosion or deforestation. Finally, focusing on a net energy ratio for a given fuel obscures the fact that not all forms of energy are equally valuable. For example, electricity is clearly more valuable than the potential fossil energy in coal, natural gas or petroleum, which is why we routinely accept 'negative' net energy ratios for electricity generation. Likewise, liquid fuels for transportation are considered more valuable than the various feedstocks that are used to produce them. Thus, the direct comparison of various fuels for use in specific contexts using

[32] See Patzek, Tad W. "Thermodynamics of the Corn-Ethanol Biofuel Cycle". *Critical Reviews in Plant Sciences*, 23(6) (2004): 519-567; and Pimentel, David and Tad W. Patzek. "Ethanol Production Using Corn, Switchgrass, and Wood; Biodiesel Production Using Soybean and Sunflower". *Natural Resource Research*, 14(1) (2005): 65-76.

multiple energy and environmental metrics yields the most valuable insights into the relative benefits and costs of these fuels.

For these reasons, this study provides several different metrics to compare alternative fuels and vehicles, both with the baseline fuel (gasoline) and with each other. This study presents results for WtW total, fossil and petroleum energy use, as well as emissions of the three main GHGs and five harmful pollutants. The author hopes that the several metrics included in this study (i.e. total, fossil and petroleum energy, GHG and criteria pollutant emissions), as well as the easy and objective comparison of each fuel to gasoline and the other alternative fuels will provide a more accurate analysis of the merits of the various fuels included in this study than a simple net energy metric. However, this study does provide net (fossil) energy ratios for the various fuel production pathways analyzed so as to allow comparison with other literature.

Finally, it must be noted that this study seeks to consider several fuel and vehicle technologies that are either just being commercialized or are still in development stages and are expected to reach the market in the near future. A horizon of time must therefore be provided in order for these fuels and technologies to develop and to allow the requisite distribution infrastructures to be deployed. Additionally, the composition of the light-duty transport sector does not change overnight. It takes approximately 15-20 years for all (or nearly all) of the vehicles on the road today to be replaced by new vehicles.[33] Due to these considerations, this study performs its WtW analysis for the year 2025.

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[33] See ibid. Supplemental Tables 45 and 46.

1.3 Study Limitations

As discussed above, the primary intent of this study is to explore the potential of several different alternative transportation fuels and vehicles to reduce petroleum consumption in the light-duty transport sector, although special attention will also be paid to alternatives that reduce fossil energy use and emissions of GHGs and harmful pollutants. To do so, this study conducts a WtW analysis of the full fuel production and vehicle operation stages – i.e. the WtW pathway – providing results for 17 different metrics including total, fossil and petroleum energy inputs as well as emissions of GHGs and criteria pollutants (see Section 2 below). This should allow objective comparisons between the various alternative fuels/vehicles considered using each of the metrics included in this study. However, this study has several limitations that should be openly acknowledged.

First, while this study makes objective comparisons between various alternative fuels/vehicles easy using each of the individual metrics, it does not attempt to provide an overarching index of comparison that incorporates overall performance on all of the various metrics. To do so would require a continued analysis to determine the appropriate weight to apply to each of the 17 metrics in order to at least approximate their relative importance. This is a difficult task as each of the metrics is related to a number of different but important concerns including resource depletion concerns, environmental degradation, and impacts on health, domestic energy security and foreign policy, etc. Providing an overarching index of comparison could be useful, but would clearly involve somewhat arbitrary decisions as to the relative importance of this diverse range of impacts and concerns and would require detailed analysis to ensure that the resulting index was as useful as possible.

Additionally, like most WtW studies, this study (for the most part) does not attempt to examine the economics or relative market competitiveness of the various alternative fuels and vehicle technologies considered. Ultimately, fuel and technology costs, time-to-market readiness and consumer acceptance may determine what degree of market penetration and impact each of these alternatives can achieve. However, accurately analyzing the diverse range of economic factors affecting the ultimate costs and competitiveness of these alternative fuels and vehicles, especially with a time horizon twenty years into the future, is beyond the scope of this study. Furthermore, the intent of this study is in part to offer guidance as to which of these alternative fuels are deserving of the most attentive research and development efforts and, if necessary, financial support to aid their ultimate ability to achieve market penetration and realize the potential benefits these pathways offer.

Furthermore, this study does not include the energy and emissions embodied in the materials and structures utilized throughout the various pathways. That is, this study is not a full life-cycle analysis, as it does not take into account the energy use and emissions related to the manufacture and eventual disposal of the vehicles themselves or of the various buildings, structures, vehicles and technologies used to produce, transport and distribute the feedstocks and fuels considered by this study (see Figure 1-3 below). Undertaking such a study inevitable involves greatly extending the boundaries of the systems analyzed and involves considerable additional work. Generally, life-cycle analyses are conducted for one or perhaps a few specific fuels that deserve more in-depth analysis. Thus, a crucial step in beginning a life-cycle analysis is analyzing the WtW performance of various fuels/vehicles in order to determine which are deserving of further analysis. This study is intended to provide that initial analysis over a much wider variety of fuels and vehicles than is generally possible in a life-cycle analysis. Further analysis of the energy use and emissions embodied in the various structures, materials, vehicles and technologies relating to each of these fuel/vehicle pathways is welcomed, but is beyond the scope of this study.

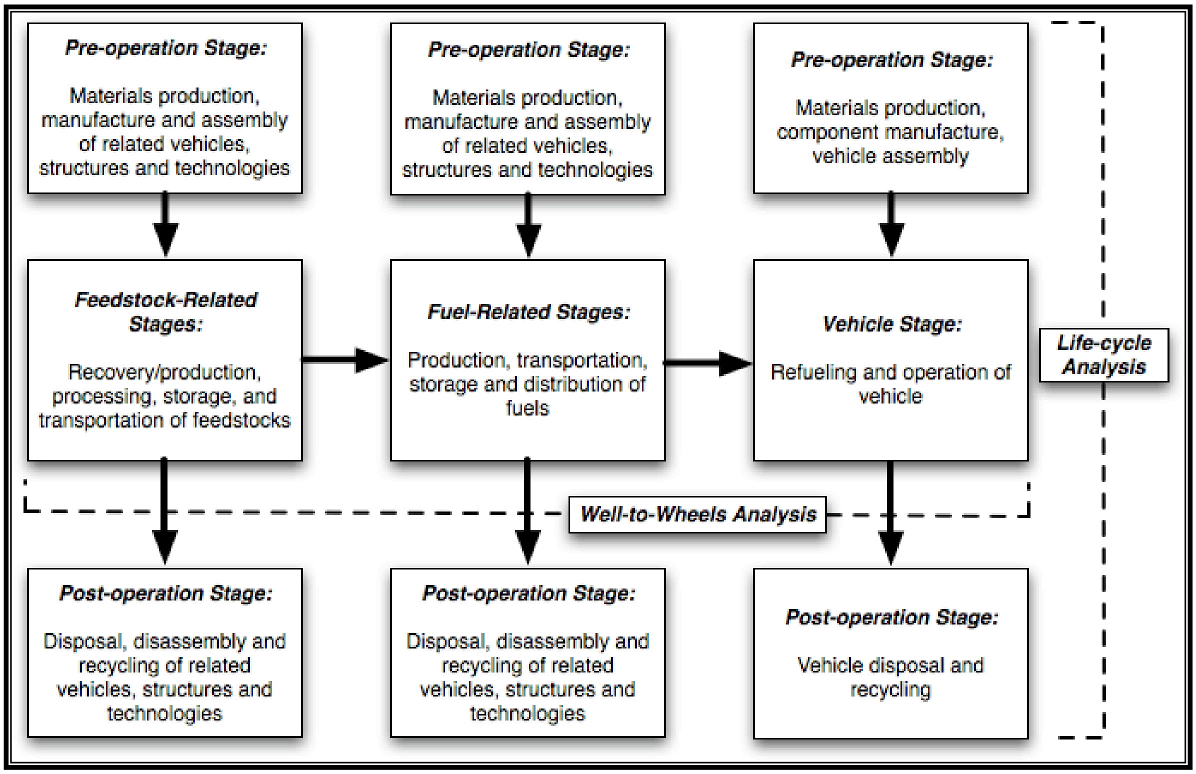

Figure 1-3: Comparative Scope of Life-cycle and Well-to-Wheels Analyses

In addition to the above limitations, this study does not address uncertainties in its assumptions through stochastic or probabilistic modeling. The version of the GREET model used to perform this study's WtW analysis (i.e., version 1.6, see Section 2 below) does not include stochastic variables. Past WtW studies utilizing GREET have made use of commercially available stochastic modeling software (i.e., Monte Carlo simulation software), but this study was unable to use such software. It appears that upcoming versions of GREET (i.e., GREET 1.7, see Section 2 below) will include stochastic variables that should allow analysis of the range of uncertainties and their affects. This may allow the further refinement of this study's conclusions.

This study also does not address the benefits of simply increasing fuel economy in conventional petroleum-fueled vehicles. Clearly, increased fuel economy translates directly to decreased fuel consumption which results in reduced petroleum energy use and emissions of GHGs and harmful pollutants. The omission of increased efficiency options from this study is not intended to imply that these options are not important. In fact, increasing the fuel economy of the light-duty transport fleet may be the best near-term option the United States has for reducing its petroleum consumption and mitigating its effect on global climate change. However, this study's focus is on determining long-term alternatives to oil-dependent transportation that can provide lasting replacements for petroleum-based fuels. As such, it does not, for the most part, consider fuel economy improvements, excepting those resulting from hybrid-electric vehicles. However, the effects of increased fuel economy can easily be extrapolated from this study's results by simply scaling the overall WtW energy use and emissions proportionate to the increase in fuel economy relative to the vehicle fuel economies assumed by this study. This should yield accurate results for the energy use and GHG metrics. Criteria pollutant emissions do not directly scale with fuel economy however, as regulations on vehicle tailpipe emissions complicate matters.

Perhaps most importantly, this study does not provide an examination of the scalability of the various alternative fuel/vehicle pathways considered. Such a scalability analysis is particularly important as several pathways are subject to fundamental constraints that may ultimately determine the degree to which these pathways can contribute to reducing petroleum energy use or emissions. There were over 211 million light-duty vehicles in the

United States in 2004, responsible for logging more than 2.6 trillion vehicle miles traveled.[34] That's more than enough for each person in the United States to drive alone from New York City to Los Angeles (or the reverse) three times each year![35] At that level of travel, the light-duty sector consumes over 16.2 quadrillion British thermal units (Btus) of energy,[36] nearly 1/6th of total United States energy consumption.[37] Clearly then, finding a true alternative to oil use in the light-duty transportation sector will require a solution that can scale to this level of consumption and beyond. Thus, a further analysis of the scalability of the alternative transportation fuels and vehicle systems considered in this study would be very fruitful. Particular attention should be paid to constraints in availability of fuel feedstocks and raw materials for vehicle systems, as well as the technical feasibility and scalability of distribution infrastructures.

Finally, it must be noted that this study in no way exhausts the range of possible fuel production and vehicle systems pathways potentially available. In particular, it does not include several potentially viable hydrogen production pathways including hydrogen produced from gasification of coal or biomass, or from high temperature electrolysis of water at next-generation nuclear power plants. Additionally, it does not include the coal or natural gas-to-liquids synthetic fuel production processes that are currently being considered for expanded use. Furthermore, none of the pathways included in this study assume that carbon capture and storage (carbon sequestration) is utilized. If carbon sequestration were used at coal or biomass gasification plants or at hydrogen production plants utilizing steam methane

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[34] ibid. Supplemental Tables 46 and 48.

[35] Assumes a driving distance from Los Angeles to New York City of 2,780 miles and a U.S. population of 298.5 million.

[36] EIA, *AEO2006* Supplemental Table 34.

[37] ibid. p. 133, Table A1. Total U.S. energy consumption in 2004: 99.68 quadrillion Btus.

reforming of natural gas, several of the pathways could see considerably improved WtW emissions of GHGs.

Clearly then, there are several areas where this study and its methodologies could be further refined. However, the author hopes this study will offer an initial inquiry into the relative benefits and costs associated with adopting alternative fuels and vehicle systems. The results presented by this study should provide guidance as to which fuels and vehicles have the most potential and which WtW pathways are deserving of additional attention and continued analysis.

2. THE GREET MODEL

This study utilizes the *G*reenhouse gases *R*egulated *E*missions and *E*nergy use in *T*ransportation spreadsheet model, referred to as GREET, to perform its well-to-wheels (WtW) analysis of the various well-to-pump (WtP) fuel production pathways, pump-to-wheels (PtW) vehicle systems and complete WtW pathways considered. The GREET model was developed by the Center for Transportation Research (CTR) at Argonne National Laboratory (ANL) beginning in 1995 and is intended to provide "an analytical tool for use by researchers and practitioners in estimating fuel-cycle energy use and emissions associated with alternative transportation fuels and advanced vehicle technologies."[38] The first version of the model was released in June 1996, and ANL has released several versions since then.[39] The current full version is GREET 1.6, and at the time of this writing, ANL is in the process of developing GREET 1.7. GREET 1.7 is still incomplete but is available from CTR as a public beta, which is referred to in this study as GREET 1.7b.[40]

The following publications provide key documentation for the development of the GREET model:

- Wang, Michael. *GREET 1.5: Transportation Fuel-Cycle Model.* (Argonne, IL: ANL, Aug. 1999).
- Wang, Michael. *GREET 1.5a: Changes from GREET 1.5.* (Argonne, IL: Argonne National Laboratory, Jan. 2000).
- Wang, Michael. *Development and Use of GREET 1.6 Fuel-Cycle Model for Transportation Fuels and Vehicle Technologies.* (Argonne, IL: ANL, June 2001).

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[38] Wang, Michael. *Development and Use of GREET 1.6 Fuel-Cycle Model for Transportation Fuels and Vehicle Technologies.* (Argonne, IL: ANL, June 2001). p. 1.
[39] ibid. p. 1.
[40] Current versions of GREET are available for public download at <http://www.transportation.anl.gov/software/GREET/index.html>.

No formal documentation was published for any versions of the model prior to GREET 1.5. Additionally, the following publications make use of different versions of GREET and provide additional documentation for the model and its development:

- Wang, Michael and H.S. Huang. *A Full Fuel-Cycle Analysis of Energy and Emissions Impacts of Transportation Fuels Produced from Natural Gas*. (Argonne, IL: ANL, Dec. 1999).
- General Motors (GM), ANL, et al. *Well-to-Wheel Energy Use and Greenhouse Gas Emissions of Advanced Fuel/Vehicle Systems – North American Analysis*. (Argonne, IL: ANL, June 2001).
- GM, ANL, et al. *Well-to-Wheels Analysis of Advanced Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions*. (Argonne, IL: ANL, May 2005).

This study utilizes GREET 1.6, but where appropriate, attempts to update the model based on the assumptions contained in GREET 1.7b. GREET 1.6 is designed to perform its analysis for 'near-term' (c. 2005) and 'long-term' (c. 2016) time horizons. As discussed above, this study performs its analysis for the year 2025, and as such, it was necessary to update many of the assumptions in GREET 1.6 to reflect this later date. Additionally, several modifications or additions were made to some of the pathways modeled by GREET. Key assumptions and any modifications to the GREET model will be discussed when appropriate in subsequent sections.

GREET attempts to model all the major WtP activities associated with the production transportation, storage and distribution of each feedstock and fuel. Additionally, GREET models the energy consumption and emissions associated with vehicle fueling and operation (the PtW stage). For a detailed explanation of GREET calculation methodologies, see Wang (1999).

A brief note on heating values: in the energy calculations performed by GREET, as well as in those throughout this study, lower heating values (LHVs) are used, unless specifically noted. The energy content of fuels can be quantified using either LHVs or higher heating values (HHVs). The difference between the LHV and the HHV of a given fuel is determined by whether or not the energy contained in the water vapor produced during fuel combustion is taken into account: HHVs include the energy content of the water vapor while LHVs do not. In stationary combustion processes, it is sometimes possible to recover a portion of the energy contained in the water vapor as steam, which can then be put to use. For motor vehicles, however, the energy contained in water vapor cannot be practically recovered. Thus, it is more appropriate to use LHVs for vehicle applications, as this study does.

2.1 GREET Well-to-Pump Feedstock and Fuel Production-related Calculation Logic

Figure 2-1 below illustrates an overview of the logic used by GREET to calculate energy use and emissions associated with WtP feedstock and fuel production stages. For each fuel production pathway, GREET derives total energy use from the energy efficiency of each production-related activity (e.g., feedstock production/recovery, fuel refining, etc.). Next, GREET estimates energy use by each fuel type consumed in these activities (e.g., natural gas, diesel, electricity, etc.) from the estimated total energy use and the shares of each fuel type. GREET calculates emissions by using energy use by fuel type and emission factors by fuel type and combustion technology shares (expressed as units of pollutant per units of energy of fuel consumed). Emissions of SO_x are calculated based on the sulfur content of the combusted fuel. For CO_2 emissions, GREET utilizes what is known as a ‘carbon-balance approach’ throughout the model. That is, the carbon in CO_2 emissions is equal to the carbon contained in the fuel combusted minus the carbon contained in any combustion emissions of VOC, CO_2 and CH_4. Finally, urban emissions of criteria pollutants are estimated from total emissions and a split of process locations between urban and non-urban locations.[41]

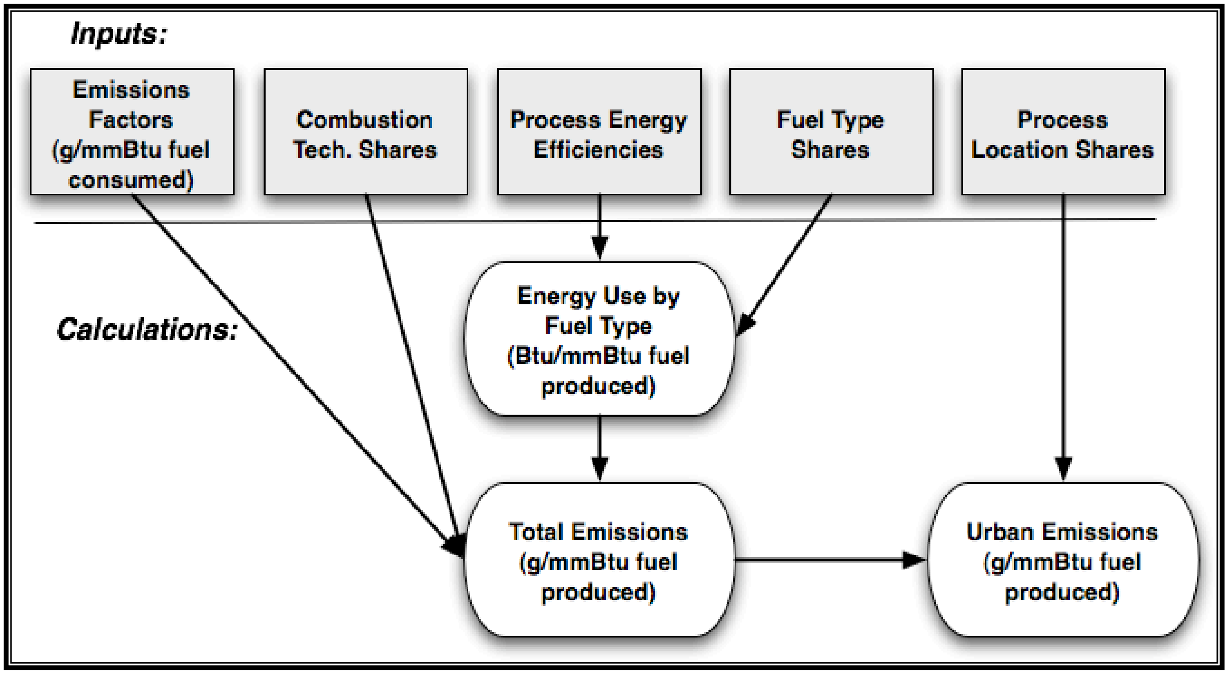

Figure 2-1: GREET Calculation Logic for Well-to-Pump Energy Use and Emissions for Activities Related to Production of Feedstocks and Fuels[42]

2.2 GREET Well-to-Pump Feedstock and Fuel Transportation-related Calculation Logic

GREET also includes detailed simulations for activities related to transportation, storage and distribution of feedstocks and fuels. Figure 2-2 below summarizes the simulation logic for transportation-related activities used by GREET. For a given transportation mode (e.g., ocean tanker or pipeline for crude oil transportation), GREET specifies input

[41] See GM, ANL, et al. *Well-to-Wheels Analysis of Advanced Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions*. (Argonne, IL: Argonne National Labs, May 2005). p. 14.
[42] See ibid. p. 14.

assumptions of energy intensity of the transportation mode (i.e., energy use per unit of mass per distance traveled), transportation distance, energy use by fuel type, and emission factors by fuel type. The model then calculates energy use and emissions for the given mode of transporting a product. Transportation of a given product often involves multiple transportation modes (again, crude oil transportation typically utilizes both ocean tankers and pipelines). Thus, GREET models energy use and emissions for transporting a given product as the share-weighted average of all the transportation modes for the product.[43]

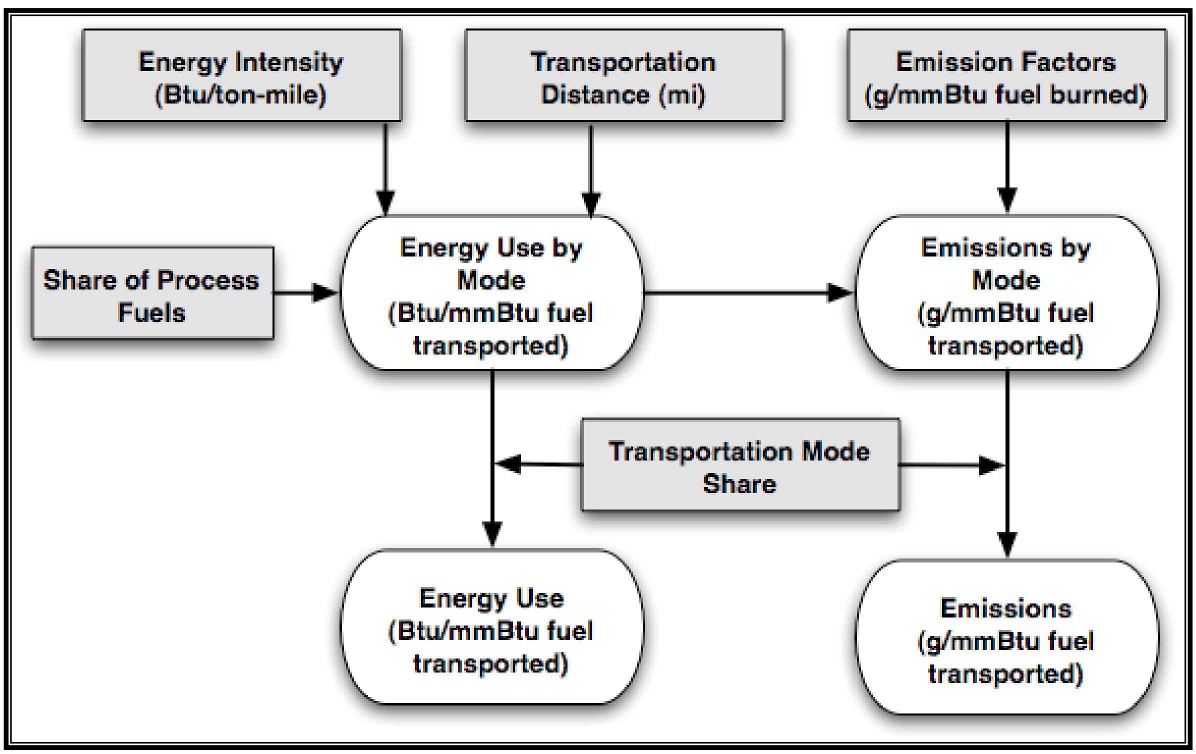

Figure 2-2: GREET Calculation Logic for Well-to-Pump Energy Use and Emissions for Activities Related to Transportation of Feedstocks and Fuels

Again, the reader should refer to Wang (1999) for continued discussion of the WtP feedstock and fuel transportation-related calculation logic utilized by GREET.[44]

[43] See ibid. p. 14.
[44] See in particular Wang (1999) Volume 1, Section 3.

Additionally, the bulk of GREET's current transportation logistics assumptions were developed for the GM, ANL (2001) WtW study. The reader should refer to that publication for more on these assumptions.[45]

Note that combining the feedstock and fuel production-related energy use and emissions with those associated with the feedstock and fuel transportation-related values yields the total upstream WtP energy use and emissions associated with each mmBtu of fuel available at fueling station pumps.

2.3 GREET Pump-to-Wheels Vehicle Fueling and Operation-related Calculation Logic

The GREET model includes energy use and emissions profiles, specified in units of energy or pollutant per vehicle mile traveled, for an assortment of conventional and advanced vehicle systems. Absolute values, excepting those for SO_x and CO_2 (discussed below), are specified for the baseline vehicle (a spark-ignition gasoline internal combustion engine vehicle) while the energy use and emissions for each of the other vehicle systems are specified relative to those for the baseline vehicle. The relative vehicle energy use and emissions values included in GREET 1.6 were developed for use in the GM, ANL, et al. (2001) and GM, ANL, et al. (2005) WtW studies utilizing GM's proprietary Hybrid Powertrain Simulation Program (for energy use) and MOBILE 6.2 on-road vehicle emissions simulation software (for emissions). The reader is referred to those publications for details.[46]

[45] See in particular, GM, ANL, et al. (2001), Volume 3, Section 5.
[46] See GM, ANL, et al. (2001) Volume 2, p. 2-1 (for energy use) and GM, ANL, et al. (2005), pps 64-66. (for emissions)

As before, SO_x emissions are calculated based on the sulfur content of the fuels while CO_2 emissions are calculated using the carbon-balance approach.

The GM vehicle simulations included the following minimum vehicle performance requirements described in Figure 2-3 below.[47] Additionally, all vehicles are assumed to meet Federal Tier 2 Bin 5 emissions standards (see Table 2-1). Federal Tier 2 emissions standards were adopted for all light-duty vehicles by the U.S. Environmental Protection Agency (EPA) in 2001 and are being phased in from 2004 to 2009.[48] The Tier 2 standards establish several 'bins' with separate emissions standards for the full 'useful' life of the vehicle (i.e., 100,000 to 120,000 miles [mi]), allowing vehicle manufacturers to certify different vehicles in different bins. However, by 2009, when the Tier 2 standards are fully phased in, the EPA will require the sales-weighted average certification level for each manufacturer to meet Bin 5 standards.[49]

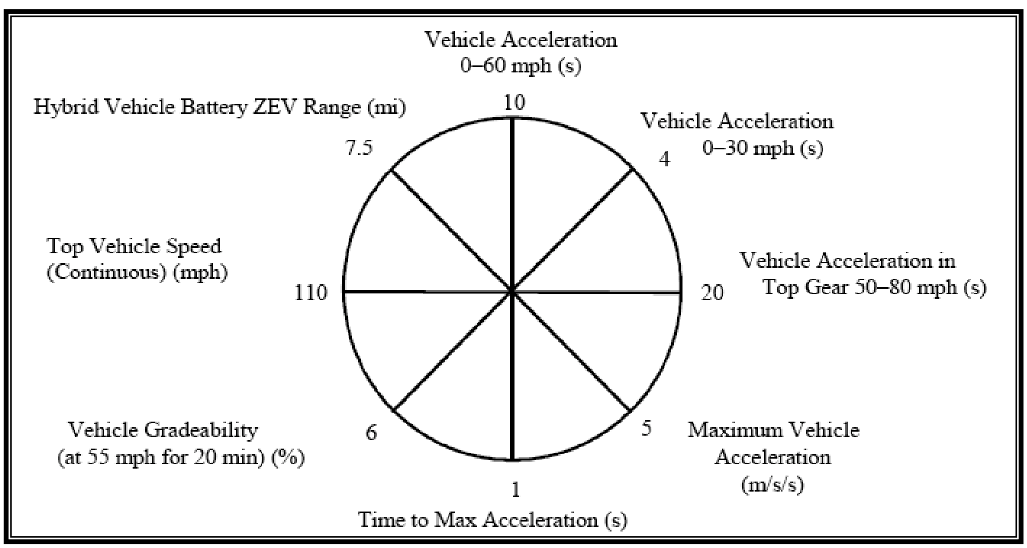

Figure 2-3: Minimum Vehicle Performance Requirements[50]

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[47] Note: these are relatively strict performance requirements designed to be representative of typical North American vehicle consumer expectations. These standards may prohibit substantial engine downsizing (for fuel economy optimization) in certain vehicle types. If consumer performance expectations

[48] See EPA. *Summary of Light-Duty Vehicle Emissions Standards*. (Washington D.C.: EPA). p. 1.

[49] See GM, ANL (2005), p. 62.

[50] From GM, ANL (2005), p. 58.

Table 2-1: Federal Tier 2 Full-Useful-Life Light-duty Vehicle Emissions Standards (g/mi)[51]

Bin	*NO_x*	*CO*	*PM*
8	0.20	4.2	0.02
7	0.15	4.2	0.02
6	0.10	4.2	0.01
5	**0.07**	**4.2**	**0.01**
4	0.04	2.1	0.01
3	0.03	2.1	0.01
2	0.02	2.1	0.01
1	0.00	0.0	0.00

2.4 Results of GREET Well-to-Wheels Fuel Cycle Energy Use and Emissions Calculations

The GREET model estimates energy use and emissions rates, in Btu/mi or g/mi for each WtW fuel/vehicle system pathway. In order to illustrate the contribution of each major upstream stage to total fuel-cycle energy use and emissions, GREET divides WtW results into three subcategories: feedstock, fuel, and vehicle operation. As shown in Figure 1-2 above, the feedstock subcategory includes energy use and emissions associated with the production or recovery, processing, transportation, storage and distribution of the feedstock; the fuel subcategory includes values associated with the production, transportation, storage and distribution of the fuel; and the vehicle operation stage includes energy use and emissions associated with fueling and operating the vehicle. The energy use and emissions rates calculated by GREET can then be used to objectively compare different WtW fuel/vehicle system pathways.

To aid in these comparisons, GREET calculates energy use for total energy, fossil fuel-derived energy (a subset of total energy including energy from coal, natural gas and

[51] See EPA *Summary of Light-Duty Vehicle Emissions Standards*, p. 1.

petroleum) and petroleum-derived energy (a subset of fossil energy). Additionally, GREET calculates total and urban emissions of the criteria pollutants, VOC, CO, NO_x, PM10 and SO_x, as well as total emissions of the three main greenhouse gases (GHGs), CO_2, CH_4 and N_2O. Finally, the GREET model combines the three GHGs based on the 100-year global warming potential (GWP) of each gas to estimate total GWP-weighted GHG emissions, as defined by the Intergovernmental Panel on Climate Change (IPCC)[52] (see Table 1-2). GWP is a simple measure of the relative radiative (heat-absorbing) effects of various GHG emissions and is defined as the cumulative radiative force between the present and some chosen time horizon caused by a unit mass of gas emitted now, weighted relative to CO_2. Signatories to the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change adopted the IPCC-recommended GWPs for the 100-year time horizon and each signatory country uses them to calculate its baseline GHG emissions and projecting emission reductions. The Protocol regulates the three major GHGs included in GREET.

Table 2-2: 100-year Global Warming Potential of the Three Main Greenhouse Gases[53]

Greenhouse Gas	***Global Warming Potential***
CO_2	1
CH_4	21
N_2O	310

[52] See Intergovernmental Panel on Climatic Change. *Climate Change 1995: The Science of Climate Change, Contribution of Working Group I to the Second Assessment Report of the Intergovernmental Panel on Climate Change*. (Cambridge, MA: Cambridge University Press, 1996).
[53] Wang (1999), Volume 1, p. 32.

3. WELL-TO-PUMP FUEL PRODUCTION PATHWAYS

Figure 1-3 above summarized the feedstocks and fuels considered in this study. Major feedstocks include petroleum, natural gas, biomass (including woody and herbaceous cellulosic biomass and corn), and electricity. Additionally, this study includes the various feedstocks used in electricity production: i.e., coal, natural gas, petroleum, nuclear, biomass, and other renewables. This study examines the following fuels produced from these feedstocks: reformulated gasoline (30-ppm sulfur content with 2% O_2 content by weight), low-sulfur diesel (15-ppm sulfur content), liquefied petroleum gas, compressed natural gas, gaseous and liquid hydrogen, electricity, and ethanol (pure ethanol or E100 and E85 – 85% EtOH and 15% RFG by volume).

Figure 1-3 summarizes the overall range of feedstocks and fuels analyzed in this study but does not describe the detailed fuel production options modeled for various feedstock-to-fuel pathways. For example, important factors for natural gas-based pathways include the source of the natural gas (i.e., North American [NA] or Non-North American [N-NA]), while crucial factors for the biomass-based pathways are whether or not the biomass is sourced from a dedicated energy crop or from waste biomass. Table 3-1 below lists the 29 main well-to-pump (WtP) fuel production pathways considered in this study. Additionally, 17 of the fuel pathways are combined with electricity (using the U.S. average mix) to model combined fuel pathways for various types of plug-in hybrid electric vehicles. These fuel pathways are denoted in Table 3-1 with a ^. Finally, all ten of the biomass pathways as well as the remote renewables to electricity via GH2 pipeline are calculated using two different methods for allocating energy and emissions to co-products produced during the fuel production stages (e.g., electricity co-produced during ethanol production from cellulosic biomass or animal feed co-produced during corn ethanol production – see Section 3.3.4 below) and are denoted in Table 3-1 with an *. Considering these additional permutations, a total of 70 full WtP fuel production pathways are modeled in this study. Each of the WtP pathways are discussed in the following sections, which are divided based on primary feedstock. Additionally, please refer to Table 3-2 below for details on the properties of each of the fuels included in this study.

Table 3-1: Well-to-Pump Fuel Production Pathways Considered in this Study

Feedstock	***Fuel***
Petroleum	(1) Reformulated gasoline (RFG) – 30-ppm sulfur (S), 2% oxygen-content by weight (5.75% EtOH by wt. as oxygenate)^
	(2) Low-sulfur diesel (LSD) – 15-ppm S^
Natural Gas	(3) NA NG (70%) and petroleum (30%) to liquefied petroleum gas (LPG)
	(4) NA NG to compressed natural gas (CNG)
	(5) NA NG to gaseous hydrogen (GH2) via steam-methane reforming at central plants (SMR)^
	(6) NA NG to liquid hydrogen (LH2) via SMR at central plants^
	(7) N-NA NG to CNG
	(8) N-NA NG to GH2 via SMR at central plants^
	(9) N-NA NG to LH2 via SMR at central plants^
Biomass	(10) Corn to ethanol (E100)*
	(11) Corn to ethanol (EtOH) in E85 (15% EtOH and 85% RFG by volume)^*
	(12) Herbaceous cellulosic biomass (switchgrass) to E100*
	(13) Herbaceous cellulosic biomass (switchgrass) to EtOH in E85^*
	(14) Herbaceous cellulosic biomass (waste) to E100*
	(15) Herbaceous cellulosic biomass (waste) to EtOH in E85^*
	(16) Woody cellulosic biomass (hybrid poplar) E100*
	(17) Woody cellulosic biomass (hybrid poplar) to EtOH in E85^*
	(18) Woody cellulosic biomass (waste) to E100*
	(19) Woody cellulosic biomass (waste) to EtOH in E85^*
Electricity	(20) U.S. ave. mix electricity (for battery electric vehicles [BEVs] and plug-in hybrid-electric vehicles [PHEVs])
	(21) U.S. ave. mix electricity to GH2 via electrolysis at fueling stations^
	(22) U.S. ave. mix electricity to LH2 via electrolysis at fueling stations^
	(23) High renewables mix electricity (for battery electric vehicles [BEVs] and plug-in hybrid-electric vehicles [PHEVs])

Table 3-1: WtP Fuel Production Pathways Considered in this Study (*Continued*)

Feedstock	***Fuel***
Electricity (*continued*)	(24) High renewables mix electricity to GH2 via electrolysis at fueling stations^
	(25) High renewables mix electricity to LH2 via electrolysis at stations^
	(26) Remote renewables to GH2 via electrolysis at remote renewables, transmitted via H2 pipeline^
	(27) Remote renewables to LH2 via electrolysis at remote renewables, transmitted via H2 pipeline^
	(28) Remote renewables to electricity (for BEVs and PHEVs), transmitted via high voltage direct current transmission lines
	(29) Remote renewables to electricity (for BEVs and PHEVs), transmitted from remote renewables as GH2 via pipeline to high temperature fuel cell power plants*

^ - pathways combined with electricity (from U.S. ave. and/or high renewables mix) to model combined fuel pathways for various plug-in hybrid-electric vehicles
* - pathways modeled using two different methods to allocate energy use and emissions associated with co-products produced during the fuel production stages

Table 3-2: Properties of Fuels Included in this Study

Fuel	***Lower Heating Value***	***Density***	***Carbon Ratio***	***Sulfur Ratio***
Liquid Fuels	**(Btu/gal)**	**(g/gal)**	**(% by wt.)**	**(ppm by wt.)**
Reformulated gasoline (5.75% EtOH by wt. as oxygenate)	113,377	2,802	83.7%	26
Low-sulfur diesel	128,000	3,240	87.0%	12
Liquefied petroleum gas	84,000	2,000	82.0%	0
Liquid hydrogen	30,900	269	0.0%	0
Ethanol	76,000	2,996	52.2%	0
E85 (85% EtOH, 15% RFG)	81,565	2,967	57.0%	4
Gaseous Fuels	**(Btu/SCF)**	**(g/SCF)**	**(% by wt.)**	**(ppm by wt.)**
Compressed natural gas	928	20.5	74.0%	7
Gaseous hydrogen	288	2.5	0.0%	0
Electricity	**(Btu/kWh)**	**(n/a)**	**(n/a)**	**(n/a)**
Electricity	3,412	-	-	-

3.1 Petroleum Pathways

This study includes two vehicle fuels produced from petroleum: 30-ppm sulfur (S) reformulated gasoline (RFG) with an oxygen (O_2) content of 2% by weight (5.75% ethanol by weight as oxygenate) and 15-ppm S low-sulfur diesel (LSD). The EPA began phasing in nationwide requirements for low-sulfur reformulated gasoline in 2004 with 30-ppm average sulfur content required by 2006.[54] Additionally, the Federal Energy Policy Act (EPACT), enacted in August 2005, legislated the repeal of the 2% O_2-content requirements for RFG[55] as well as banned the use of methyl tertiary butyl ether (MTBE) as an oxygenate.[56] 26 states have also banned the use of MTBE at the state level over concerns about contamination of ground water in the case of leakage from storage or distribution tanks.[57] However, EPACT also instituted a Federal Renewable Fuels Standard which mandates 4 billions gallons of renewable fuels be blended in 2006, increasing each year to 7.5 billion gallons by 2012.[58] To meet this requirement most efficiently, the American Petroleum Institute reports "that the majority of refiners have chosen to blend … ethanol in RFG. As RFG blended with ethanol cannot be blended with RFG not blended with ethanol, except in limited circumstances, the decision to switch is not easily reversible."[59] Thus, this study assumes that RFG contains 5.75% ethanol (from corn) by weight as an oxygenate, enough to ensure an oxygen content of 2% which is commensurate with pre-EPACT standards.

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[54] United States Department of Transportation, Federal Highway Administration (FHWA). "Emissions Standards". *Transportation Air Quality – Selected Facts and Figures.*
[55] Oxygenates are added to gasoline to increase octane ratings and ensure cleaner fuel combustion.
[56] American Petroleum Institute. "The End of the RFG Oxygenate Mandate in 2006". (Washington D.C.: American Petroleum Institute, March 2006). p. 1.
[57] ibid. p. 1.
[58] ibid. p. 1.
[59] ibid. p. 1.

Use of ultra-low sulfur diesel (15-ppm maximum sulfur content) will also be phased in beginning in June 2006 in order to prepare U.S. diesel vehicles for the Federal Tier 2 emissions standards scheduled to be implemented in 2007.[60] This represents a 97% reduction over current sulfur content levels for diesel fuels of 500-ppm.[61] Ultra-low sulfur diesel fuel is necessary because sulfur damages the vehicle emissions control systems required to meet the new Tier 2 standards for NO_x and PM10.[62]

In addition to RFG and LSD, petroleum is used as a feedstock in the production of liquefied petroleum gas (LPG), or propane. However, natural gas provides 70% of the feedstock[63] used to produce the LPG included in this study with petroleum making up the remaining 30%. As such, LPG is discussed in the natural gas pathways section to follow. Similarly, E85 and B20, both discussed in the biomass section below, contain 15% RFG and 80% LSD by volume respectively. Petroleum is also used as the feedstock for several of the process fuels (e.g., residual oil) modeled in GREET, but the production of process fuels are not discussed in detail in this study.[64]

Figure 3-1 below illustrates the main stages in the WtP petroleum pathways included in this study. These include petroleum recovery, petroleum transportation, petroleum refining to products and fuels, and the transportation, storage and distribution of fuels. These stages are discussed below.

[60] FHWA.
[61] American Petroleum Institute, p. 1.
[62] ibid. p. 1.
[63] In the form of natural gas plant liquids.
[64] For a discussion of process-fuels derived from petroleum, see Wang (1999), Volume 1, Section 4.1.

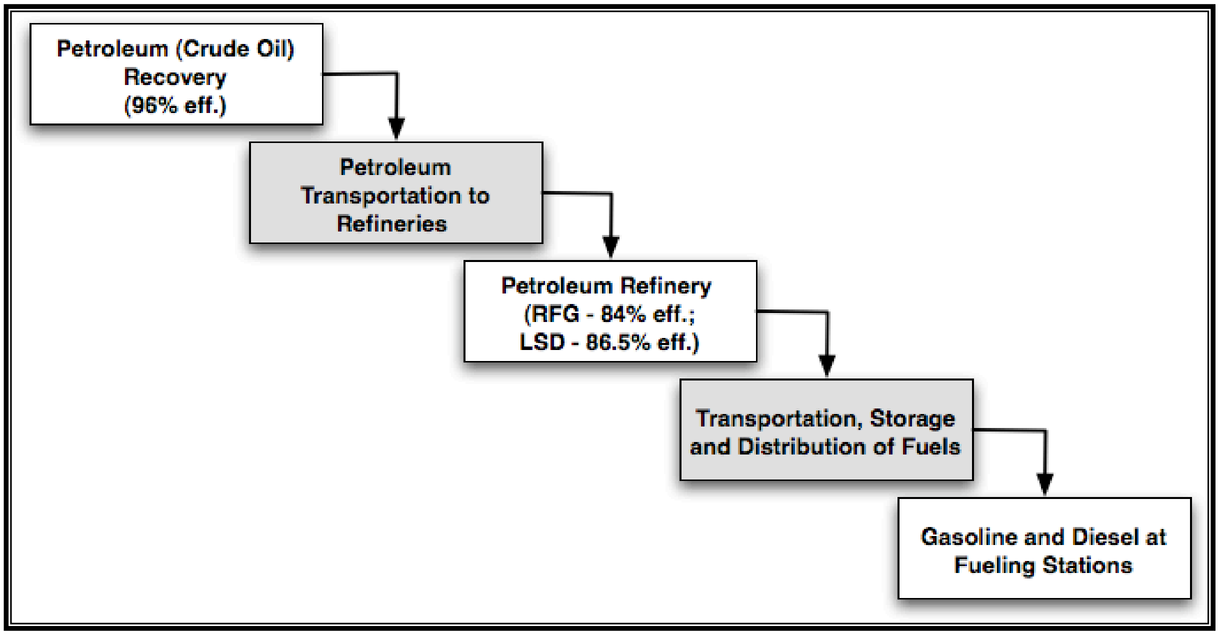

Figure 3-1: Major Stages in Petroleum Fuel Production Pathways

3.1.1 Petroleum Recovery and Transportation

The petroleum recovery stage includes activities related to extracting crude oil from underground deposits (e.g., drilling and extraction) and storage and treatment of the oil in oil fields. Crude oil can be extracted using conventional extraction techniques in which the natural pressure of underground oil reservoirs moves the oil to the surface.[65] This is the most efficient option for oil recovery. However, when the oil is highly viscous or an oil field has begun to mature and natural pressure is no longer sufficient to extract the oil, less efficient artificial lift or enhanced oil recovery techniques must be utilized.[66]

Additionally, when crude oil is brought to the surface, it is mixed with a combination of water, and natural gas, which must then be separated from the crude in on-site treatment facilities before the oil can be transported through pipelines. On-site treatment facilities

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[65] Wang (1999), Volume 1, p. 36.
[66] ibid. p. 36. Artificial lift methods include as using surface or subsurface pumps; or enhanced oil recovery methods include thermal recovery, chemical flooding, and gas displacement.

usually include oil/natural gas separators, oil/water separators, oil storage tanks, and produced water reservoirs. In some cases, i.e., when the oil fields are in remote locations, the natural gas associated with crude recovery cannot be economically utilized and is thus vented or flared. GREET does not account for the energy content in associated oil field gas as it is not the intended resource.[67] However, the emissions associated with venting or flaring gas associated with petroleum recovery are included in the emissions for this stage.

The energy use associated with each of these recovery-related activities is implicitly modeled in the energy efficiency for the petroleum recovery stage. The GM, ANL, et al. (2005) WtW study assumes an efficiency range of 96%-99% for petroleum recovery. This study adopts the lower end of that range (i.e., 96%) for the efficiency of the petroleum recovery stage. This figure is selected to take into account the increased reliance on less efficient enhanced oil recovery techniques and unconventional oil sources (e.g., heavy and deepwater crude, oil sands[68], etc.) expected by 2025.

GREET takes into account the production of both domestic and foreign crude oil to determine recovery efficiencies, transportation modes, and distances from oil fields to U.S. refineries.[69] The United States imported 65% of its crude oil in 2004.[70] Howver, U.S. domestic oil production peaked in 1971 and has been steadily declining since then while consumption has continued to rise. By 2025, domestic production is expected to fall to just

[67] Wang(1999), Volume 1, p. 37 and GM, ANL, et al. (2001), Volume 3, p. 11.
[68] Note, GREET 1.7b does not assume a decrease in recovery efficiency by 2020, the farthest date included in the model's projections. However, GREET 1.7b models the production of crude oil from oil sands, or bitumen, which is significantly more energy-intensive than conventional oil recovery: GREET 1.7b assumes 95.2% and 85.6% for the efficiency of surface mining and in-situ production of bitumen respectively; the bitumen must then be upgraded, a 98.7% efficiency process according to model which also consumes an additional 100-300 SCF of H2 per mmBtu of upgraded bitumen. The share of bitumen in U.S. refinery feedstocks is expected to increase by 2025 as Canada is the United States' largest supplier of foreign oil and Canada is becoming increasingly reliant on their large Alberta oil sands deposits to meet increased demand from the U.S.
[69] GM, ANL et al. (2005), p. 18.
[70] EIA, *AOE2006*, p. 152, Table A11.

under 5 mmbbl/d from a 2004 level of 5.4 mmbbl/d while demand for crude is forecasted to rise from 15.5 mmbl/d to 17.3 mmbbl/d over the same period.[71] Thus, by 2025, imported crude will make up over 71% of total U.S. consumption of crude oil.[72] As such, this study increases the share of imported crude assumed in the model. Overall energy losses during transportation of petroleum are still minimal, however, due to the bulk transportation of crude.[73] For more on the transportation of crude, see GM, ANL (2005) et al.[74] Figure 3-2 below illustrates an overview of petroleum transportation stages.

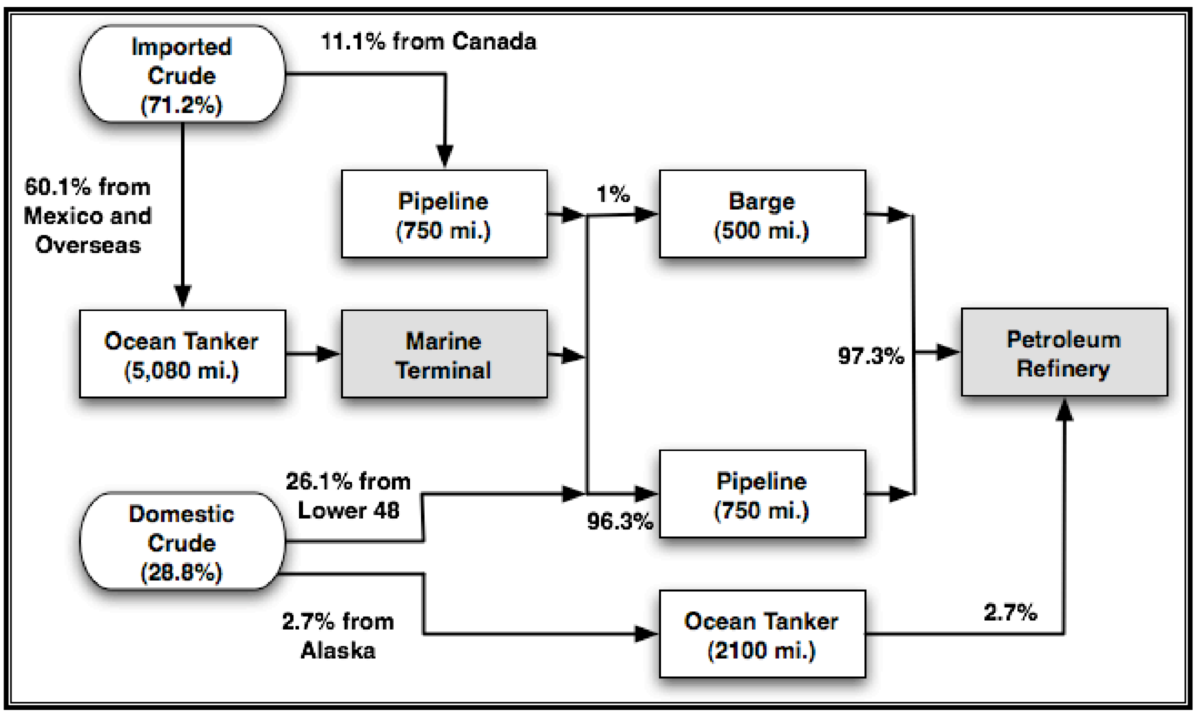

Figure 3-2: Transportation of Petroleum from Oil Fields to U.S. Petroleum Refineries[75]

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[71] ibid. p. 152, Table A11.
[72] ibid. p. 152, Table A11.
[73] Wang (1999), Volume 1, p. 40.
[74] See specifically Volume 3, Section 5.2.1.
[75] See GM, ANL, et al. (2001) Volume 3, p. 46. Shares of imported and domestic crude and shares of Alaskan and Lower 48 crude from EIA, *AEO2006*, p. 153, Table A11. Shares of imported crude from Canada and elsewhere are an average of shares for 2000 to 2005 (see EIA, “U.S. Imports by Country of Origin”). Assumes Canadian crude is imported via pipeline while Mexican and overseas crude is transported via ocean tanker. An extensive pipeline system connects Canada and the U.S. while few span the U.S. Mexico boarder (see DOE, “An Energy Overview of Mexico”). Average 1-way trip distances and U.S. transportation mode shares as per ANL, *GREET 1.6*. See ‘Inputs’ and ‘T&D’ worksheets.

3.1.2 Refining, Transportation, Storage and Distribution of Petroleum-based Fuels

Refining petroleum into reformulated gasoline and low-sulfur diesel is the most significant of the petroleum-based WtP stages in terms of energy losses. Petroleum refineries refine petroleum into various fuels and petrochemicals. As such, a WtP analysis of specific fuels (e.g., RFG or LSD) requires the allocation of refinery energy use and emissions to each of its products. The efficiencies for various petroleum-based fuels utilized in GREET were developed by the GM, ANL (2001) WtW study as well as subsequent efforts by ANL.[76]

Refinery efficiency and the share of products produced from that refinery are affected by the quality of the crude oil used as feedstock. The degree of desulphurization required to meet low-sulfur fuel specifications also affects refinery energy efficiency. The two main measures of crude oil quality are the American Petroleum Institute (API) gravity and the sulfur content. Crude oil varieties with API gravities below 30 are referred to as 'heavy' crude, while those with gravities above 30 are referred to as 'light' crude. API gravity is one indication of the amount of gasoline and other light (i.e., low density) fuels that can be refined from a supply of crude. Lighter crude varieties will yield more of these desirable light fuels.

The sulfur content of the crude provides an indication of the amount of desulphurization that will be required to meet tightening standards for sulfur content in vehicle fuels. Obviously, the higher the sulfur content, the more energy intensive desulphurization is and thus the lower the refinery efficiency for low-sulfur gasoline and referred to as 'sour' crude, while those with sulfur contents below 0.4% are known as 'sweet'

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[76] See Wang, Michael, Hanjie Lee, and John Molburg. *Allocation of Energy Use in Petroleum Refineries to Petroleum Products: Implications for Life-Cycle Energy Use and Emission Inventory of Petroleum Transportation Fuels*. (Argonne, IL: ANL, 2003).

diesel fuels. High sulfur crude varieties with sulfur contents greater than 2% by weight are crude. Clearly, light, sweet crude varieties are the most desirable and thus fetch the highest price on the market, while heavy and sour varieties are less desirable and require more energy intensive processing to refine into valuable fuels.[77]

The default GREET assumptions for refinery efficiencies for 30-ppm sulfur RFG and 15-ppm LSD are 84.5% and 87% respectively.[78] However, these values are based on a 1999 survey of the weighted-average quality of crude varieties used as feedstocks for U.S. refineries.[79] By 2025, the average quality of crude is expected to fall as the bulk (i.e., 69.5%) of total world oil reserves are located in five Middle Eastern countries, each of which rank in the top six in the world for proven reserves: Saudi Arabia (1st), Iran (3rd), Iraq (4th), the United Arab Emirates (5th) and Kuwait (6th).[80] None of these countries produce sweet crude and both Kuwait and Iraq produce heavy crude.[81] In contrast, countries producing sweet crude, including Nigeria, Angola, Norway, Gabon and Colombia, rank much lower based on proven reserves – i.e., 10th, 13h, 19th, 32nd and 36th in the world, respectively – and some are already past their peak of production.[82] As such, it is quite likely that the average quality of crude feedstocks for U.S. refineries will decline by 2025. GREET 1.7b seems to take this into account and assumes a decrease of 0.6% in refinery efficiency for RFG between 2000 and 2020.[83] This study thus assumes a similar reduction from the default GREET assumptions

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[77] See GM, ANL (2001), Volume 3, pps. 9-10 for a discussion of crude oil quality and its effect on refining.
[78] ANL, *GREET 1.6*, 'Inputs' worksheet.
[79] GM, ANL (2001), Volume 3, pps. 9-10.
[80] United States Central Intelligence Agency. "Rank Order – Oil – Proved Reserves". *The World Factbook.* April 20, 2006. <http://www.cia.gov/cia/publications/factbook/rankorder/2178rank.html>. Accessed 4/25/2006. Of course, as discussed in Section 1.1 above, reported reserves for these OPEC countries could be quite a bit higher than they are in reality.
[81] GM, ANL (2001), Volume 3, p. 10.
[82] CIA, "Rank Order – Oil – proved reserves".
[83] *GREET 1.7 Beta,* worksheet 'Fuel_Prod_TS'.

described above, resulting in the following refinery efficiencies: 84.0% for RFG and 86.5% for LSD.

As with crude oil, the GREET model takes into account both domestically produced and imported refined petroleum products. Imported fuels make up a relatively small but growing portion of U.S. refined products. In 2004, imports made up just under 10% of total refined products consumed in the United States, while the Energy Information Administration (EIA) predicts that the share of imports will grow to 12.9% by 2025.[84] As such, this study increases the share of imported gasoline and diesel assumed in the model appropriately. Again, refer to GM, ANL, et al. (2001) for more on the transportation, storage and distribution of petroleum-based fuels. Figures 3-3 and 3-4 below illustrate the overview of gasoline and diesel transportation, storage and distribution stages.

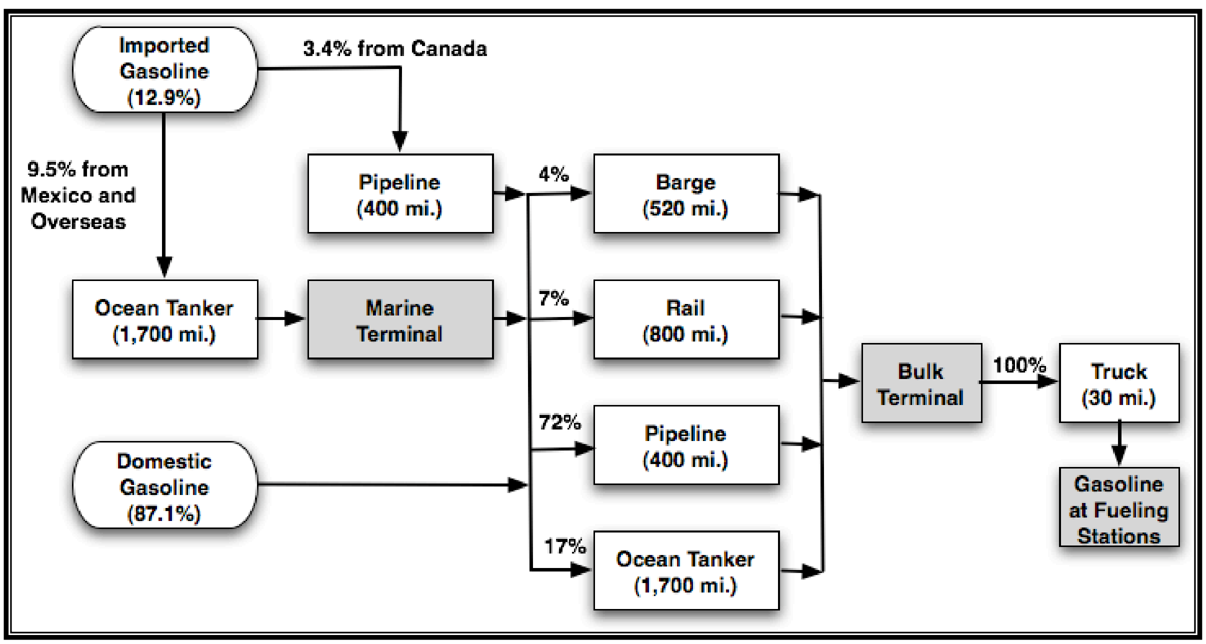

Figure 3-3: Transportation, Storage and Distribution of Reformulated Gasoline[85]

[84] EIA, *AEO2006*, p. 153, Table A11.
[85] See following footnote.

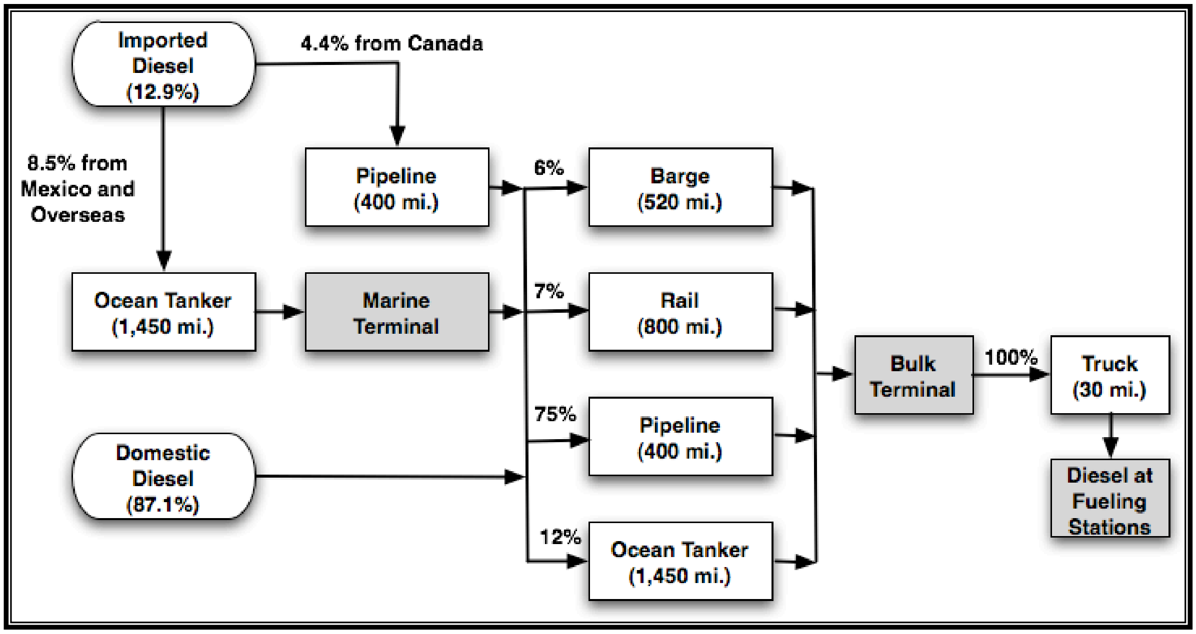

Figure 3-4: Transportation, Storage and Distribution of Low-Sulfur Diesel[86]

3.1.3 Summary of Energy Use and Emissions Assumptions and Results for Petroleum-based Fuel Production Pathways

Table 3-3 below summarizes the major assumptions used to calculate energy use and emissions for the petroleum-based fuel pathways described above. Table 3-4 summarizes energy use and emissions results for petroleum-based WtP fuel production stages. Additionally, several of the fuel production pathways considered in this section are combined with the electricity pathways discussed in Section 3.4 to model combined WtP fuel pathways for plug-in hybrid electric vehicles. These WtP results are presented in Table 3-17 in Section 3.4 below.

[86] See GM, ANL, et al. (2001) Volume 3, pps. 47-48. Shares of imported and domestic refined products from EIA, *AEO2006*, p. 153, Table A11. Shares of imported gasoline and diesel from Canada and elsewhere are an average of shares for 2000 to 2005 (see EIA, "U.S. Imports by Country of Origin"). Assumes Canadian fuels are imported via pipeline while Mexican and fuels from overseas are transported via ocean tanker. An extensive pipeline system connects Canada and the U.S. while few span the U.S. Mexico boarder (see DOE, "An Energy Overview of Mexico"). Average 1-way trip distances and U.S. transportation mode shares as per GREET 1.6.

Table 3-3: Key Assumptions for Petroleum-based Fuel Production Pathways

Assumption	*Value*
Petroleum Recovery-	
Crude recovery efficiency (%)	96.0%
Field gas flared (Btu/mmBtu crude oil recovered)	16,800
CH4 non-combustion emissions (g/mmBtu crude oil recovered)	9.0
Share of process fuels (%)	
Crude oil / Residual oil	1.0% / 1.0%
Diesel fuel / Gasoline	15.0% / 2.0%
Natural gas / Electricity	62% / 19.0%
Petroleum Transportation-	
Share of imports out of total U.S. crude (%)	71.2%
Share of imports from Canada out of total U.S. crude (%)	11.1%
Share of petroleum transported by mode (%)*	
Ocean tanker	61.5%
Barge	1.0%
Pipeline	104.4%
Average trip distance for petroleum transported by mode (mi)	
Ocean tanker	5,080^
Barge	500^
Pipeline	750
Refining of Petroleum-based Fuels-	
Reformulated gasoline:	
Refining efficiency (%)	84.0%
Sulfur content (ppm by wt.)	30
Oxygen content (% by wt.)	2.0%
Oxygenate type	Ethanol
Oxygenate content (% by wt.)	5.75%
Low-sulfur Diesel:	
Refining efficiency (%)	86.5%
Sulfur content (ppm by wt.)	15
Share of refinery process fuels (%)	
Residual oil / Natural Gas	3.0% / 30.0%
Coal / Electricity	13.0% / 4.0%
Refinery still gas	50.0%

Table 3-3: Key Assumptions for Petroleum-based Fuel Production Pathways (**Continued**)

Assumption	*Value*
Transportation, Storage and Distribution of Petroleum-based Fuels-	
Share of imports out of total U.S. refined products (%)	12.9%
Share of imports from Canada out of total U.S. gasoline / diesel (%)	3.4% / 4.4%
Share of gasoline / diesel transported by mode (%)*	
Ocean tanker	26.5% / 20.5%
Barge	4.0% / 6.0%
Pipeline	75.4% / 79.4%
Rail	7.0% / 7.0%
Truck	100.0% / 100.0%
Average trip distance for gasoline/diesel transported by mode (mi)	
Ocean tanker	1,700^ / 1,460^
Barge	520^ / 520^
Pipeline	400 / 400
Rail	800 / 800
Truck	30^ / 30^
VOC emissions - transportation, storage and distribution (g/mmBtu)	
Gasoline – evaporation / spillage	8.1 / 3.4
Diesel – evaporation / spillage	0.0 / 3.5

* Transport mode shares may add up to more than 100% as fuels may be transported through multiple modes. Additionally, individual mode shares may exceed 100% as some fuels pass through the same type of mode during more than one leg of their journey.
^ Round-trip energy use and emissions for this transport mode are calculated – i.e. back-haul trips are assumed to be empty.

Table 3-4: Well-to-Pump Energy Use and Emissions Results for Petroleum-based Fuel Production Pathways

(Btu or g/mmBtu of fuel available at fueling station pumps)	*30-ppm Sulfur Reformulated Gasoline (5.75% EtOH as oxygenate)*	*15-ppm Low-Sulfur Diesel*
Total Energy	307,502	251,408
Net Fossil Energy Ratio	3.31	4.06
Fossil Fuels	301,759	246,176
Petroleum	125,831	108,300
CO2	23,939	19,773
CH4	117.735	111.035
N2O	1.533	0.339
GHGs	26,887	22,210
VOC: Total	17.390	8.816
CO: Total	21.025	18.209
NOx: Total	50.185	44.647
PM10: Total	16.450	10.993
SOx: Total	24.392	21.401
VOC: Urban	5.670	2.462
CO: Urban	4.218	3.648
NOx: Urban	7.392	6.484
PM10: Urban	1.618	1.407
SOx: Urban	7.015	6.110

3.2 Natural Gas Pathways

This study includes four fuels derived from natural gas (NG) as a feedstock: compressed natural gas (CNG), liquefied petroleum gas (LPG), and gaseous and liquid hydrogen (GH2 and LH2) produced via steam methane reforming (SMR) of natural gas at central plants. Additionally, this study considers the use of both North American (NA) and non-North American (N-NA) supplies of natural gas as feedstocks for each of these fuels, with the exception of LPG.[87] While non-North American supplies of natural gas made up only 1.8% of total U.S. natural gas consumption in 2004,[88] North American natural gas supplies will be unable to fully meet increasing levels of demand.[89] As such, the United States is expected to become increasingly reliant on N-NA NG, which must be imported as liquefied natural gas (LNG) via specialized supertankers. As such, the EIA predicts that in their 'business-as-usual' scenario, the share of N-NA NG will reach 12.92% by 2025.[90] However, in this scenario, only 0.4% of total U.S. natural gas is consumed by the transportation sector.[91] Thus, while the fuels considered in this study can theoretically be produced from NA NG, if natural gas is to truly become a major feedstock for transportation fuels by 2025, the resulting large increase in natural gas demand will have to be met by N-NA supplies.

In addition to the transportation fuels considered in this section, natural gas is used as a fuel for electricity generation as well as a number of processes modeled in GREET (i.e., to

[87] LPG is produced from natural gas plant liquids produced at domestic natural gas processing plants. As such, N-NA NG is not an appropriate feedstock for LPG production.
[88] EIA, *AEO2006*, p. 155, Table A13.
[89] North America possesses only 4.3% of proven world natural gas reserves. CIA, "Rank Order – Natural Gas – proved reserves".
[90] EIA, *AEO2006*, p. 155, Table A13.
[91] ibid. p. 155, Table A13.

produce process steam or heat). Feedstocks for electricity generation are discussed in Section 3.3.1 below, while process fuels are not discussed in detail in this study. It must be noted that GREET 1.6 assumes that only North American natural gas is utilized in electricity generation and as a fuel for the various processes included in the model. Given the increased share of Non-North American natural gas consumed in the United States by 2025, this study modifies GREET to split the share of NA and N-NA NG appropriately when determining energy use and emissions associated with natural gas for electricity generation or process fuel.[92] That is, this study assumes that 12.92% of natural gas consumed in the United States is imported from overseas as LNG by 2025.

Figure 3-5 below illustrates the major stages in the production of CNG from NA and N-NA natural gas. For the NA natural gas-based pathway, natural gas is pipelined to fueling stations where it is compressed. Gaseous fuels cannot be effectively shipped overseas. Thus, for the N-NA natural gas-based pathway, the natural gas is liquefied and then transported to the United States via specialized LNG supertankers. It is then re-gasified at LNG terminals[93] and pipelined to fueling stations like NA NG supplies. The N-NA NG-based pathway thus incurs additional efficiency losses compared to the NA NG-based pathway due to the production and inter-continental transportation of LNG.

Figure 3-6 summarizes the major stages in the LPG fuel production pathway. LPG (predominately propane) is separated from natural gas at North American NG processing

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[92] That is, this study modified GREET 1.6 to calculate energy use and emissions for natual gas used as a process fuel or for electricity generation as a weighted average of the energy use and emissions associated with the production, transportation and distribution of NA NG and N-NA NG based on their respective shares in total U.S. consumption.

[93] This stage incurs no efficiency losses as the LNG is simply allowed to naturally boil off into its gaseous state which is recovered and then pipelined.

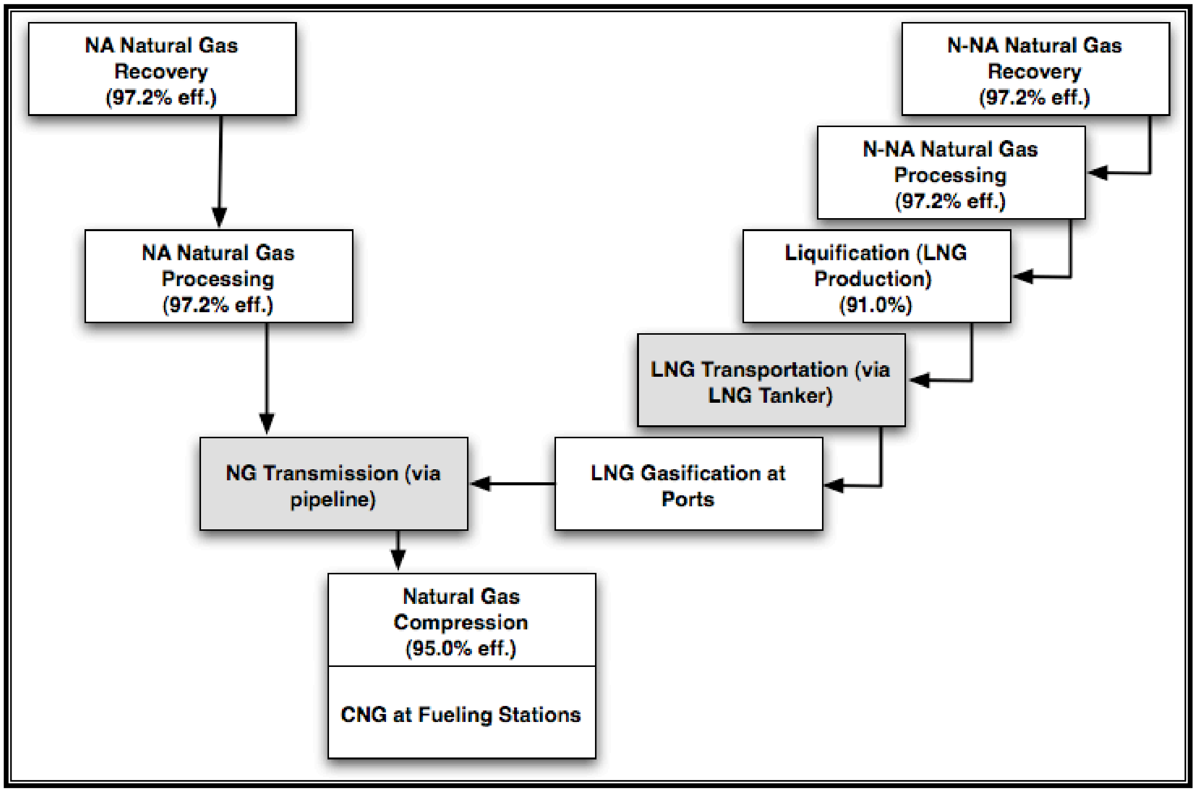

Figure 3-5: Major Stages in Compressed Natural Gas Production Pathways

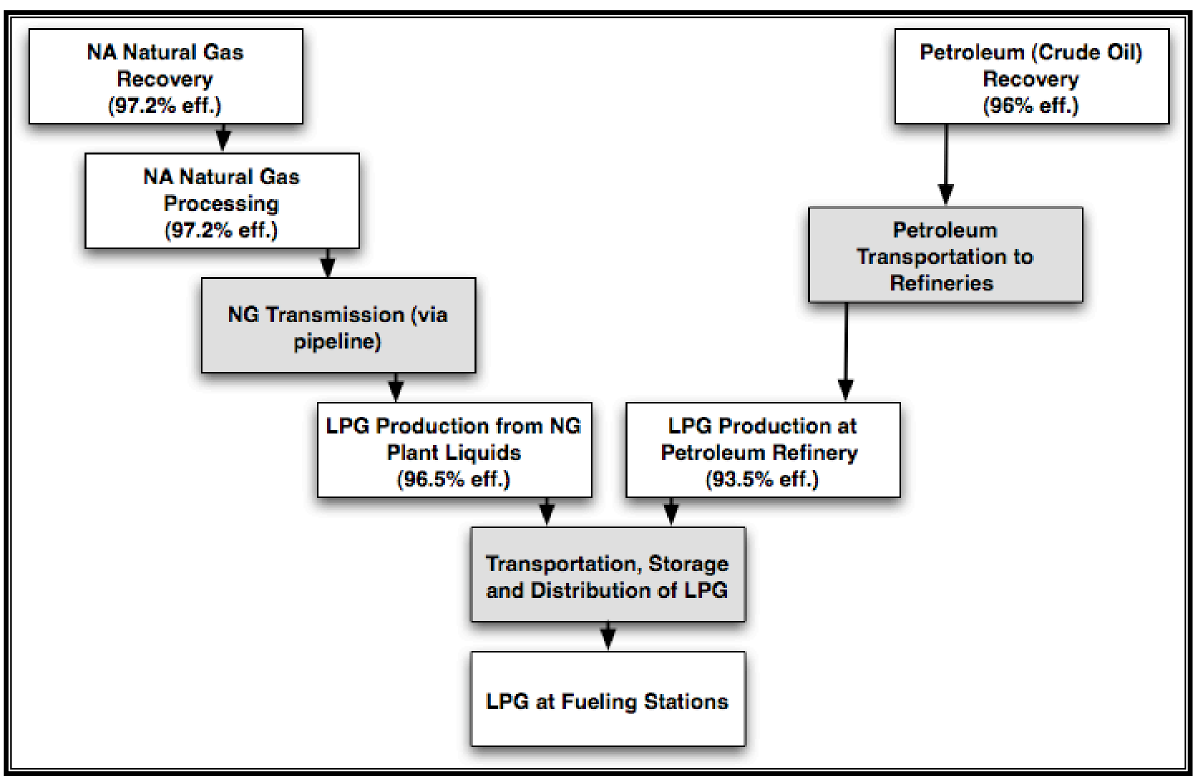

Figure 3-6: Major Stages in Liquefied Petroleum Gas Production Pathway

facilities as well as refined from petroleum at petroleum refineries.[94] This study assumes that NG provides 70% of the feedstock for LPG while the remaining 30% is provided by petroleum.[95] After production, LPG is transported via pipelines, rail and barges to storage and distribution facilities before finally being transported by truck to fueling stations.

Figure 3-7 below shows the major stages in the production of gaseous hydrogen (GH2) from natural gas. GH2 is produced from natural gas at central plants via steam methane reforming (SMR). As with CNG, both NA and N-NA NG-based pathways are considered for GH2. Again, N-NA NG must be shipped to the United States as LNG where it joints NA NG pipelined to central SMR facilities. After production, GH2 is then transmitted to fueling stations via pipelines. Finally, GH2 must be compressed in order to

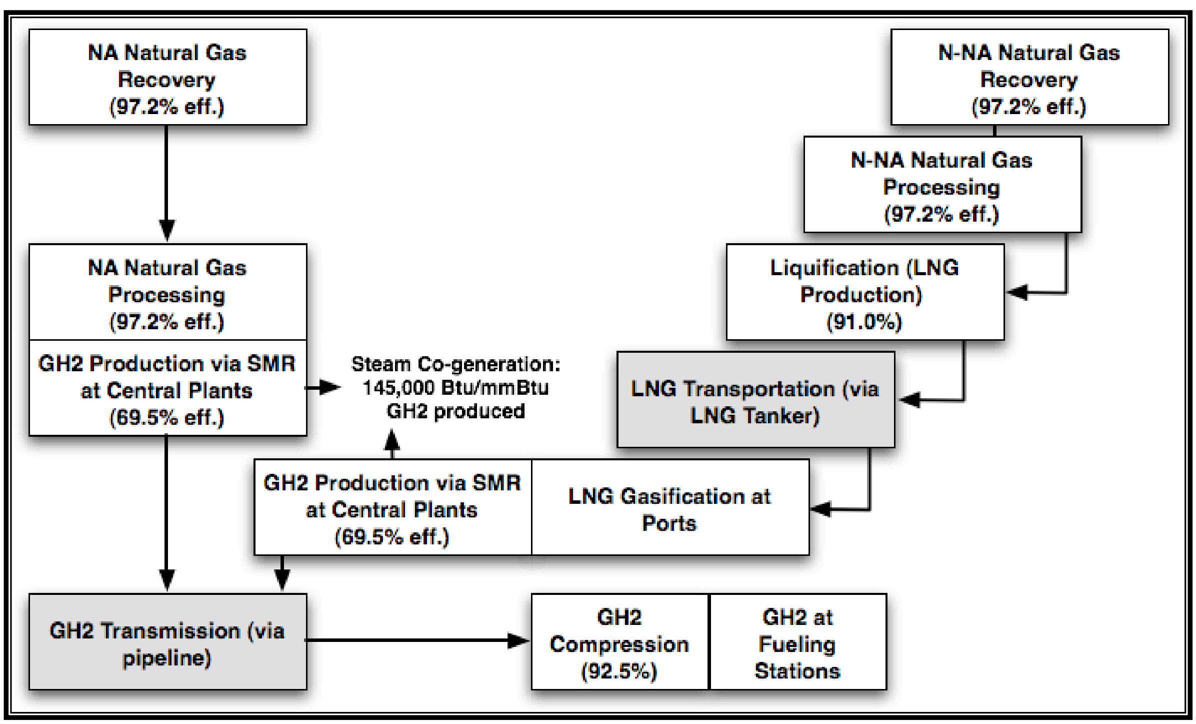

Figure 3-7: Major Stages in Gaseous Hydrogen Production From Natural Gas Pathways

[94] See 2.2.1 above for a discussion of petroleum recovery, transportation and refining.
[95] This share is from ANL, *GREET 1.7 Beta* for the year 2020. See worksheet 'Fuel_Prod_TS'.

provide the requisite range for fuel cell vehicles. Note that GH2 is not very dense (see Table 3.2 above) and as such, compression of GH2 incurs significant energy losses.

Figure 3-8 illustrates the major stages in the production of liquid hydrogen (LH2). LH2 is denser than GH2 and is thus one possible way to provide longer range for fuel cell vehicles with limited on-board storage space. The LH2 pathways begin with gaseous hydrogen produced from NA or N-NA NG via SMR at central plants. The resulting GH2 is then cryogenically liquefied into LH2, a very energy intensive process. For the N-NA NG-based pathway, LH2 is produced at SMR plants near natural gas fields and then shipped to the United States, like LNG, in specialized supertankers.[96] It then joins LH2 from the NA

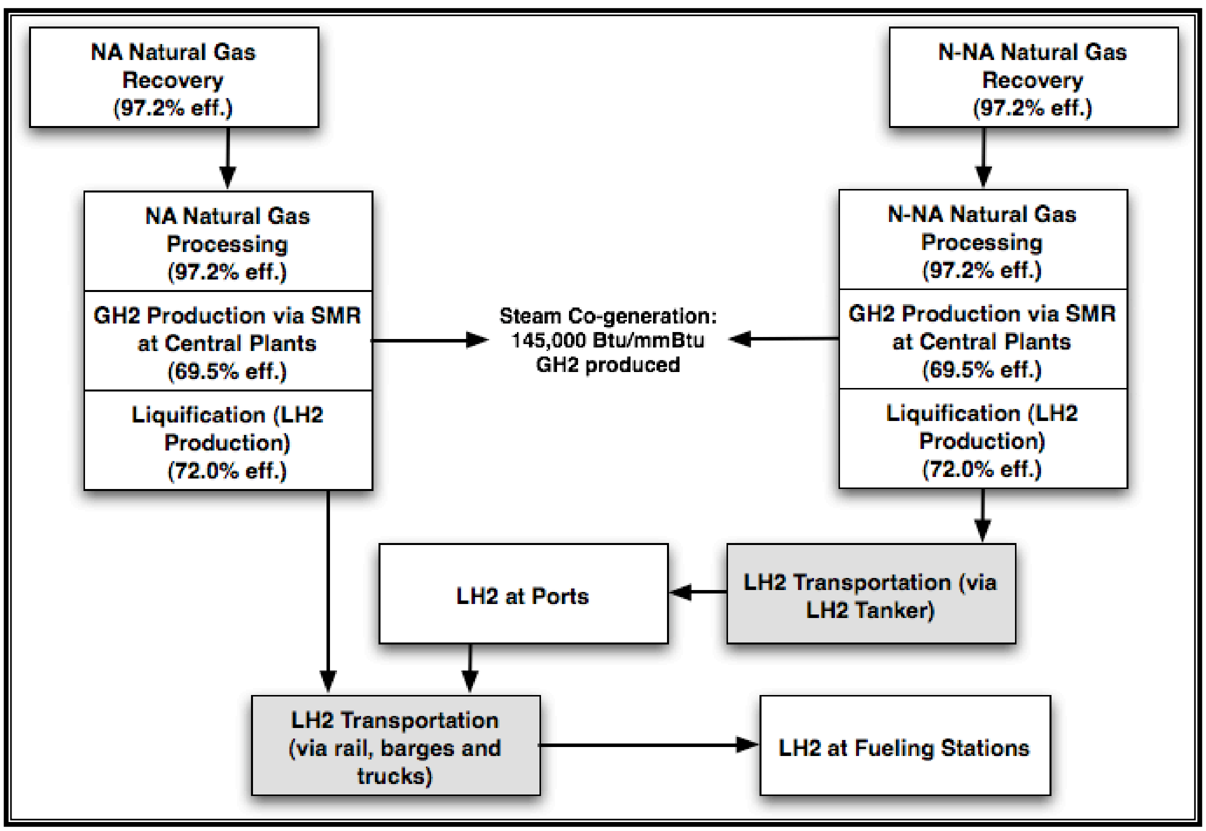

Figure 3-8: Major Stages in Liquid Hydrogen Production From Natural Gas Pathways

[96] There are currently no LH2 super tankers in operation. However, the technology is very similar as that for LNG tankers and is theoretically and potentially economically feasible. GM, ANL (2001) reports that researchers in Japan have explored the economic and technical feasibility of cross-ocean transport of LH2 via cryogenic tankers. See Volume 3, p. 22.

NG-based pathway and is distributed to fueling stations via rail, barges and trucks. LH2 must be kept cryogenically cooled at temperatures below 20 K (-423° F) for the entirety of these pathways which clearly presents a technical challenge and incurs significant energy losses. As such, the overall energy efficiency of LH2 pathways is lower than that for GH2 pathways.

3.2.1 Natural Gas Recovery, Processing, and Transportation

Natural gas is recovered at gas fields by lifting it from underground deposits. The gas is then transmitted via small distribution pipelines to processing plants, which remove impurities and separate out natural gas liquids to produce pipeline-quality natural gas. Based on the published figures for GREET 1.7b, this study assumes that both the recovery and processing stages operate at 97.2% efficiency.[97] During the recovery and processing stages, some natural gas may leak during lifting and transmission. This leaked gas is thus included in calculations of energy use and emissions associated with the natural gas recovery and processing stages.

LPG is produced on-site at North American natural gas processing plants and thus requires no further transportation of the feedstock for fuel processing. Similarly, this study assumes GH2 is produced via steam methane reforming at central plants located adjacent to NG processing facilities or LNG terminals and thus no further transportation of the feedstock is required. LH2 is similarly produced in facilities located adjacent to processing and SMR plants. Finally, for CNG from North American NG, pipeline-quality NG for later compression is available at the NG processing plant gates. For CNG from N-NA NG, LNG

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[97] See ANL, GREET *1.7 Beta*, worksheet 'Fuel_Prod_TS'. Note, GREET 1.6 assumes slightly higher recovery and processing efficiencies of 97.5%, but this study selects the figures from the more recent GREET version.

is produced in facilities adjacent to processing plants and then readied for shipment via ocean tanker for later use as CNG. Thus, there are no significant feedstock-related transportation stages associated with the transportation of natural gas.

3.2.2 Production, Transportation, Storage and Distribution of Fuels Produced from Natural Gas

As discussed above, this study considers the production of four natural gas-based fuels: compressed natural gas, liquefied petroleum gas, and gaseous and liquid hydrogen.

Compressed Natural Gas from Natural Gas:

As mentioned previously, pipeline-quality NG suitable for compression is available at NG processing plant gates for CNG from NA NG. This gas is pipelined to fueling stations where it is compressed and stored for later fueling of CNG vehicles. This study assumes that CNG is stored on-board vehicles at a pressure of about 3,600 pounds per square inch (psi).[98] In order to achieve this onboard pressure, natural gas in storage tanks at CNG fueling stations must be maintained at approximately 4,000 psi.[99] This study assumes that fueling stations use an even mix of electric and NG-fueled compressors to compress pipeline gas into CNG. Electric and NG-fueled compressors are assumed compress natural gas at 97% and 93% efficiency, respectively, yielding a weighted average efficiency for NG compression of 95%.[100]

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[98] Pressures greater than 3,600 psi were not considered because the increase in natural gas density at pressures beyond 3,600 psi diminish due to the nonlinearity of natural gas compression. See GM, ANL, et al. 2005, p. 19.
[99] See GM, ANL, et al. (1999) Volume 3, p. 21.
[100] Efficiencies and shares as per ANL *GREET 1.6* and *GREET 1.7 Beta*. See 'Inputs' worksheet in both versions.

Non-North American NG for use as CNG must be imported to the United States as LNG via ocean tankers. Thus, the pipeline-quality gas produced at N-NA NG processing facilities is liquefied at adjacent facilities and readied for transport via ocean tanker. The liquification of natural gas involves further processing of the pipeline-quality NG to remove any remaining water, carbon dioxide, sulfur or other compounds that may freeze and then cooling the purified NG to below 110 K (-261° F).[101] This study assumes a natural gas liquification efficiency of 91.5%.[102] After liquification, the LNG is stored as a cryogenic liquid in insulated vessels at pressures between 50-150 psi[103] and shipped overseas to LNG terminals in North America. There, the LNG is re-gasified and pipelined to fueling stations for compression into CNG. Figure 3-9 below summarizes the fuel-related transportation flow for the two CNG pathways.

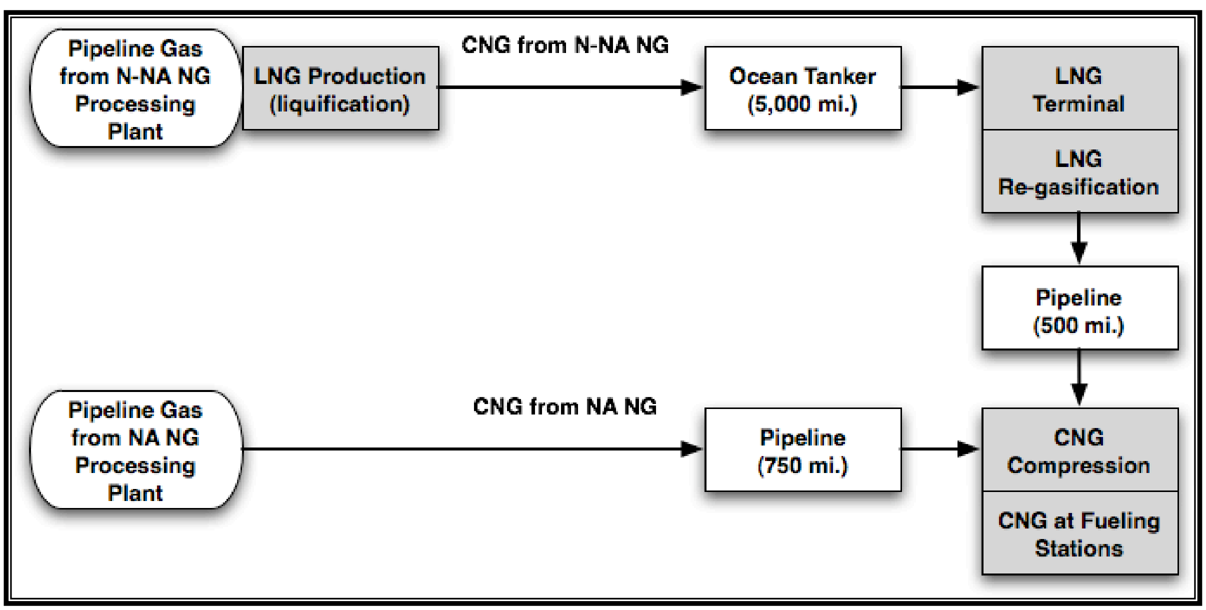

Figure 3-9: Transportation and Distribution of Compressed Natural Gas[104]

[101] See GM, ANL, et al. (1999), Volume 1, p. 47.
[102] As per ANL, *GREET 1.7 Beta* figure for 2020. See 'Fuel_Prod_TS' worksheet.
[103] See GM, ANL, et al. (1999), Volume 1, p. 47.
[104] Average 1-way trip distances and transportation mode shares as per ANL, *GREET 1.6*. See 'Inputs' and 'T&D' worksheets.

Liquefied Petroleum Gas from Natural Gas and Petroleum:

Liquefied petroleum gas (LPG) is produced from natural gas at natural gas processing facilities as well as from petroleum refineries. As discussed above, this study assumes 70% of LPG is derived from natural gas, while the remaining 30% is refined from petroleum. LPG is produced from natural gas during the simple process of separating out natural gas liquids from NG during processing.[105] This study assumes an efficiency of 96.5% for LPG production from NG.[106] LPG can also be produced in petroleum refineries[107] and this study assumes the efficiency of this process is 93.5%.[108] LPG from both sources is then transported from natural gas processing facilities and petroleum refineries to bulk stations via pipelines, rail and barges and then distributed to fueling stations via truck. See Figure 3-10 below for an overview of the transportation, storage and distribution of LPG.

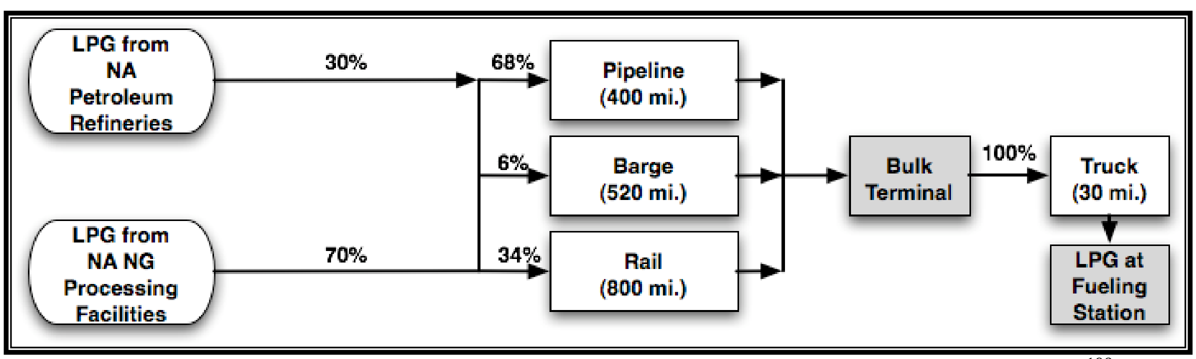

Figure 3-10: Transportation, Storage and Distribution of Liquefied Petroleum Gas[109]

[105] ibid. Volume 1, p. 47.
[106] As per ANL, *GREET 1.6* and *GREET 1.7b*. See 'Inputs' worksheet and 'Fuel_Prod_TS' worksheet respectively.
[107] See Section 2.2.1.1 above for discussion of the recovery and transportation of petroleum.
[108] ibid.
[109] Average 1-way trip distances and transportation mode shares as per ANL, *GREET 1.6*. See 'Inputs' and 'T&D' worksheets.

Gaseous Hydrogen from Natural Gas:

Gaseous hydrogen is produced via steam methane reformation at large central plants located adjacent to NG processing facilities, in the case of GH2 from NA NG, or adjacent to LNG terminals, in the case of GH2 from N-NA NG.[110] This study assumes that GH2 is produced via SMR at central plants at an efficiency of 69.5%.[111] GH2 SMR plants also generate significant quantities of steam, some of which is used as process steam within the plant. However, the remainder can be exported to nearby facilities for use as process steam or for heating. This study assumes 145,000 Btu of steam are produced per mmBtu of GH2.[112] This exported steam is assumed to offset steam normally created by burning natural gas. As such, the energy use and emissions for the GH2 plant are given a credit for the co-produced steam – that is, they are reduced by the total energy use and emissions associated with producing the natural gas-based steam offset by the exported steam from the GH2 plant. This method of allocating energy use and emissions credits to co-products is known as the 'Displacement Method' (see Section 3.3.4 below).

After production, GH2 is pipelined from the SMR plant to refueling stations. There, as with CNG, GH2 must be compressed in order to provide adequate on-board storage and operating range for fuel cell vehicles. Thus, as with CNG, GH2 is compressed and stored at fueling stations, this time to around 6,000 psi in order to allow storage on-board fuel cell vehicles at 5,000 psi.[113] This study assumes that electric compressors are used at fueling stations to compress GH2 at an efficiency of 92.5%.[114] Figure 3-11 below summarizes the

[110] See Wang (1999), Volume 1, p. 49 for a description of the steam methane reforming process.
[111] As per ANL, *GREET 1.6*. See 'Inputs' worksheet.
[112] As per ibid. Note: the overall efficiency for the SMR plant is thus 79.6% including both the GH2 and exported steam.
[113] See GM, ANL, et al. (2001), Volume 3, pps. 21-22.
[114] As per ANL, *GREET 1.6*. See 'Inputs' worksheet.

transportation and distribution of GH2.

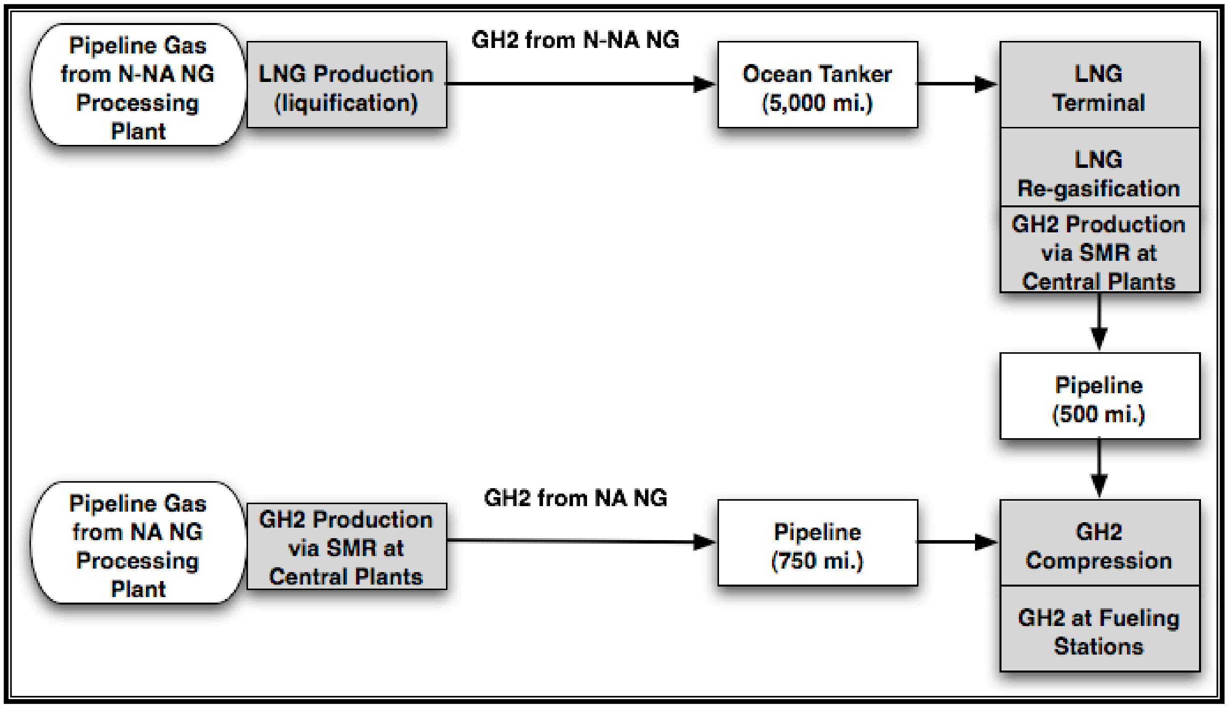

Figure 3-11: Transportation and Distribution of Gaseous Hydrogen From Natural Gas[115]

Liquid Hydrogen from Natural Gas:

Liquid hydrogen is produced so that hydrogen can be stored in a liquid form on-board fuel cell vehicles (FCVs), which increases the amount of stored fuel and extends the operating range of FCVs. The liquid hydrogen from natural gas fuel production pathways begin with GH2 produced from NA or N-NA NG at central SMR facilities as discussed above for GH2. For N-NA NG-based LH2, the SMR facility is located adjacent to the overseas natural gas processing facility, rather than at North American LNG terminals as in the case of the GH2 from N-NA NG pathway discussed above. After production via SMR, the GH2 is cooled to below 20 K (-423° F) where it assumes a cryogenic liquid state. This

[115] Average 1-way trip distances and transportation mode shares as per ANL, *GREET 1.6*. See 'Inputs' and 'T&D' worksheets.

study assumes that liquification of hydrogen at central plants is a 72% efficiency process.[116] In the case of N-NA NG-based LH2, the LH2 is then transported via specialized ocean tankers to LH2 terminals in the United States. LH2 is then transported from North American SMR plants and LH2 terminals to bulk terminals via barges and rail and then distributed to fueling stations via truck. While LH2 does extend the range of FCVs fueled with hydrogen when compared to FCVs fueled with GH2, the use of LH2 poses two major problems: first, liquefying hydrogen is a very energy intensive process which results in fewer energy and environmental benefits to LH2 when compared to GH2; and second, LH2 must remain in its cryogenic liquid state throughout the entire process of transportation, storage, distribution and fueling which clearly presents technical and cost challenges.[117] Figure 3-12 illustrates the transportation, storage and distribution of LH2 from natural gas.

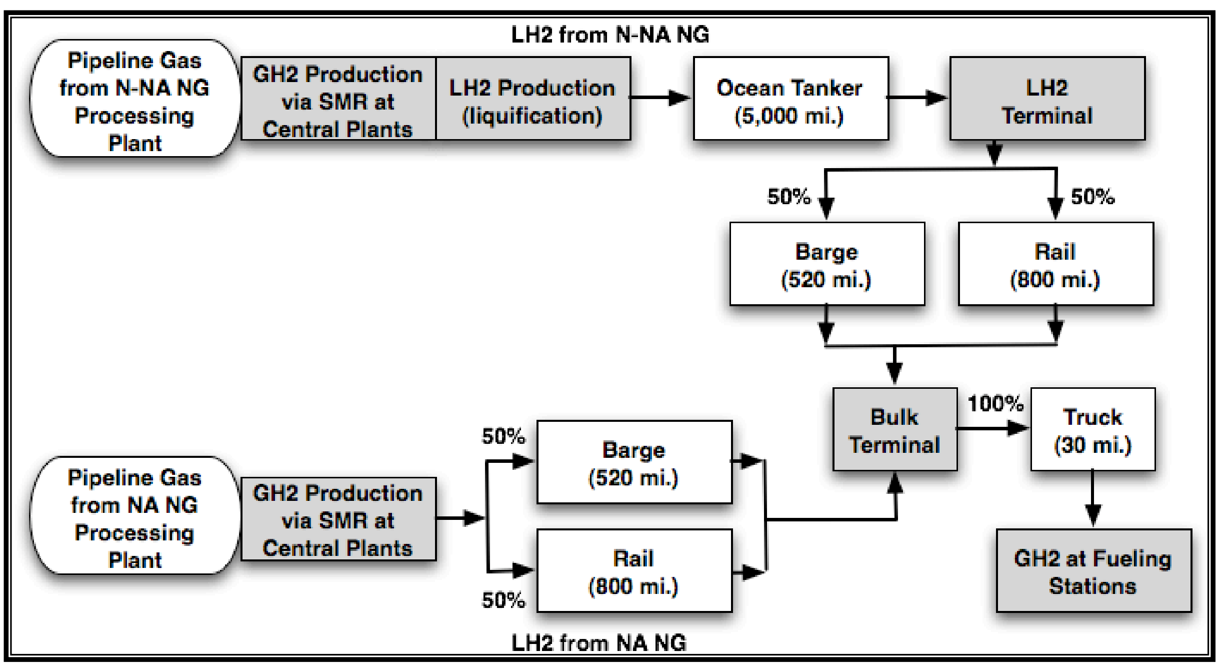

Figure 3-12: Transportation and Distribution of Liquid Hydrogen From Natural Gas[118]

[116] As per ANL, *GREET 1.7 Beta* figure for 2020. See 'Fuel_Prod_TS' worksheet.
[117] See Wang (1999), p. 50.
[118] See GM, ANL, et al. (2001), p. 50. Average 1-way trip distances and transportation mode shares as per ANL, *GREET 1.6*. See 'Inputs' and 'T&D' worksheets.

3.2.3 Summary of Energy Use and Emissions Assumptions and Results for Natural Gas-based Fuel Production Pathways

Table 3-5 below summarizes the major assumptions used to calculate energy use and emissions for the natural gas-based fuel pathways described above   Table 3-6 summarizes energy use and emissions results for natural gas-based WtP fuel production stages. Additionally, several of the fuel production pathways considered in this section are combined with the electricity pathways discussed in Section 3.4 to model combined WtP fuel pathways for plug-in hybrid electric vehicles. These WtP results are presented in Table 3-17 in Section 3.4 below.

Table 3-5: Key Assumptions for Natural Gas-based Fuel Production Pathways

Assumption	*Value*
Natural Gas Recovery and Processing-	
Natural gas recovery efficiency (%)	97.2%
CH4 losses – recovery (g/mmBtu NG recovered)	74.7
Share of process fuels – recovery (%)	
Residual oil / Diesel fuel	0.9% / 9.7%
Gasoline / Natural Gas	0.9% / 76.9%
Electricity / Feedstock loss	0.9% / 11.7%
Natural gas processing efficiency (%)	97.2%
CH4 losses - processing (g/mmBtu NG processed)	32.7
Share of process fuels – processing (%)	
Diesel fuel / Natural Gas	0.9% / 91.1%
Electricity / Feedstock loss	2.8% / 5.1%
Compressed Natural Gas-	
North American natural gas	
Average pipeline distance – processing to fueling stations (mi)	750
CH4 leakage during pipelining (g/mmBtu NG transmitted)	122.6

Table 3-6: Key Assumptions for Natural Gas-baced Fuel Production Pathways **(Continued)**

Assumption	*Value*
Non-North American natural gas	
LNG production (liquification) efficiency	91.5%
Share of process fuels – liquification (%)	
Natural gas / electricity	98.0% / 2.0%
CH4 loss due to boiling off – liquification stage (g/mmBtu LNG)	21.9
Average ocean tanker trip distance to NA LNG terminal (mi)	5,000^
CH4 loss due to boiling off – transport to NA (g/mmBtu LNG)	53.9
Average pipeline distance – LNG terminal to fueling stations (mi)	500
CH4 leakage during pipelining (g/mmBtu NG transmitted)	81.7
NG compression efficiency at stations – electric compressors (%)	97%
NG compression efficiency at stations – NG-fueled compressors (%)	93%
Share of compressors at stations – electric / NG-fueled (%)	50% / 50%
Liquefied Petroleum Gas	
LPG production efficiency from natural gas (%)	96.5%
LPG production efficiency from petroleum (%)	93.5%
Share of feedstocks for LPG production – natural gas / petroleum (%)	70% / 30%
Share of LPG transported by mode* (%)	
Barge	6.0%
Pipeline	68.0%
Rail	34.0%
Truck	100.0%
Average trip distance for LPG transported by mode (mi)	
Barge	520^
Pipeline	400
Rail	800
Truck	30^
VOC emissions – transportation of LPG (g/mmBtu LPG)	3.3
Gaseous Hydrogen from Natural Gas	
GH2 production efficiency via SMR at central plants (%)	69.5%
Steam co-produced at SMR central plants (Btu/mmBtu GH2)	145,000
North American Natural Gas	
Average pipeline distance – SMR plant to fueling stations (mi)	750

***Table 3-6: Key Assumptions for Natural Gas-based Fuel Production Pathways* (Continued)**

Assumption	***Value***
Non-North American natural gas	
LNG production (liquification) efficiency	91.5%
Share of process fuels – liquification (%)	
Natural gas / electricity	98.0% / 2.0%
CH_4 loss due to boiling off – liquification stage (g/mmBtu LNG)	21.9
Average ocean tanker trip distance to NA LNG terminal (mi)	5,000^
CH_4 loss due to boiling off – transport to NA (g/mmBtu LNG)	53.9
Average pipeline distance – LNG terminal to fueling stations (mi)	500
H_2 compression efficiency at stations – electric compressors (%)	92.5%
Liquid Hydrogen from Natural Gas	
GH_2 production efficiency via SMR at central plants (%)	69.5%
Steam co-produced at SMR central plants (Btu/mmBtu GH_2)	145,000
LH_2 production (liquification) efficiency at central plants (%)	72.0%
Share of process fuels – liquification (%)	
Electricity	100.0%
LH_2 loss due to boiling off – liquification stage (g/mmBtu LH_2)	26.5
Non-North American Natural Gas	
Average ocean tanker trip distance to NA LH_2 terminal (mi)	5,000^
H_2 loss due to boiling off – transport to NA (g/mmBtu LH_2)	53.9
Share of LH_2 transported by mode* (%)	
Barge	50.0%
Rail	50.0%
Truck	100%
Average trip distance for LH_2 transported by mode (mi)	
Barge	520^
Rail	800
Truck	30^
LH_2 loss due to boiling off – transportation (g/mmBtu LH_2)	5.5
LH_2 loss due to boiling off – storage (g/mmBtu LH_2)	42.3

* Transport mode shares may add up to more than 100% as fuels may be transported through multiple modes. Additionally, individual mode shares may exceed 100% as some fuels pass through the same type of mode during more than one leg of their journey.
^ Round-trip energy use and emissions for this transport mode are calculated – i.e. back-haul trips are assumed to be empty.

Table 3-6: Well-to-Pump Energy Use and Emissions Results for Natural Gas-based Fuel Production Pathways

(Btu or g/mmBtu of fuel available at fueling station pumps)	***LPG from North American Natural Gas and Petroleum***	***CNG from North American Natural Gas***	***CNG from Non-North American Natural Gas***	***GH2 from North American Natural Gas via Central SMR***	***GH2 from Non-North American Natural Gas via Central SMR***	***LH2 from North American Natural Gas via Central SMR***	***LH2 from Non-North American Natural Gas via Central SMR***
Total Energy	124,872	171,409	297,382	582,421	748,445	1,149,422	1,174,905
Net Fossil Energy Ratio	8.12	6.17	3.48	1.81	1.39	0.87	0.85
Fossil Fuels	123,110	162,132	287,403	551,795	716,860	1,148,243	1,173,696
Petroleum	26,969	6,768	13,486	19,825	28,244	15,806	23,435
CO2	9,519	13,159	20,980	102,101	113,477	133,217	136,756
CH4	111.908	253.883	328.876	170.115	337.375	196.453	200.793
N2O	0.172	0.242	0.417	0.549	0.778	1.348	1.409
GHGs	11,922	18,565	28,016	105,843	120,804	137,761	141,409
VOC: Total	5.313	2.388	3.438	2.325	3.968	2.324	2.995
CO: Total	10.510	22.589	25.872	13.621	19.510	21.705	23.782
NOx: Total	26.350	46.307	75.395	48.730	87.377	39.859	87.467
PM10: Total	3.092	9.102	10.421	28.876	30.648	4.537	5.072
SOx: Total	7.597	9.190	18.376	23.677	37.540	7.423	17.898
VOC: Urban	1.084	1.169	1.121	0.111	0.092	0.106	0.106
CO: Urban	0.751	14.818	14.722	1.037	0.983	0.763	0.717
NOx: Urban	1.603	29.301	29.035	4.488	3.392	1.025	1.015
PM10: Urban	0.226	0.269	0.272	0.220	0.176	0.068	0.066
SOx: Urban	0.980	0.379	0.421	1.311	0.958	0.014	0.006

3.3 Biomass Pathways

This study considers the production of ethanol from biomass – i.e. from corn and from woody and herbaceous biomass. Ethanol is normally produced via the fermentation of sugars.[119] It has properties similar to gasoline (see Table 3-2 above) and can be used to fuel spark-ignition (SI) internal combustion engines (ICEs). This study includes ethanol produced from corn as well as from woody and herbaceous cellulosic biomass (i.e. agricultural or forestry waste, urban wood waste, or fast-growing trees or grasses such as hybrid poplar trees or switchgrass grown as dedicated energy crops).

The United States consumed 3 billion gallons of ethanol in 2003, over 90% of which was produced from corn.[120] However, because of the limited supply of corn, ethanol from corn cannot supply a significant share of U.S. transportation demand. For example, the GM, ANL, et al. (2005) WtW study reports that the 3 billion gallons of ethanol consumed in 2003 already utilizes 11% of total U.S. corn production (10.1 billion bushels in 2003) and accounts for only 1.4% of total transportation energy demand.[121] While essentially no ethanol is currently produced from cellulosic biomass, extensive research and development efforts are underway and the technology could be commercialized as early as the end of this decade.[122] A joint study completed in 2005 by the U.S. Departments of Energy and Agriculture found that by mid-century, 1.3 billion dry tons or more of biomass could be sustainability harvested

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[119] Another process in development produces ethanol from cellulosic biomass by fermenting carbon-rich synthesis gas produced by the gasification of cellulosic biomass or other carbon-rich organic matter (including coal). This process is being commercialized by BRI Energy, LLC and is discussed in Section 3.3.4 below.
[120] GM, ANL, et al. (2005), pps. 21-22.
[121] ibid. p. 22.
[122] See discussion in Section 3.3.4 below.

each year in the United States for use in the bioenergy and bioproducts industries.[123] This available biomass could provide sufficient feedstock for ethanol derived from cellulosic biomass (cellulosic ethanol) to contribute a significant share of U.S. transportation energy consumption.[124]

Ethanol can be blended with gasoline in small amounts (less than 10% by volume) and used in unmodified SI gasoline engines[125] or in larger amounts in specially modified SI engines. Ethanol blends are generally abbreviated based on the percentage (by volume) of ethanol in the fuel; for example, E10 and E85 refer to ethanol-gasoline blends with 10% and 85% ethanol by volume, respectively, while E100 refers to 100% 'pure' ethanol.[126] This study considers WtP pathways for E85 and E100 blends and assumes that ethanol blends less than E100 are blended with reformulated gasoline (RFG – see Section 3.1 above). These pathways are summarized in Figures 3-13 and 3-14 below.

In addition to use in ethanol blends, ethanol is blended in small amounts into reformulated gasoline (RFG) to boost the oxygen content and octane ratings of RFG. This is discussed in Section 3.1 above. Furthermore, woody and herbaceous biomass is used as a feedstock for the production of electricity in biomass-fired power plants and its use in this capacity is discussed in Section 3.4 below.

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[123] See Perlack, Robert D., et al. *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: the Technical Feasability of a Billion-Ton Annual Supply*. (Oak Ridge, TN: Oak Ridge National Laboratory, April 2005).

[124] Perlack, et al. (2005) conclude that the available biomass would make it technically feasible for biofuels and bioproducts to offset 30% of current U.S. petroleum consumption by 2030. See the Executive Summary.

[125] Note: this study assumes that ethanol (from corn) is used as an oxygenate and blended into reformulated gasoline (RFG) at 5.7% by volume. See Section 3.1 above.

[126] Note: even E100 does not contain 100% ethanol as ethanol is generally blended with a small amount (generally less than 5% by volume) of some other non-potable alcohol or fuel (i.e. methanol, isopropanol or gasoline) so as to make it unfit for drinking as an intoxicating beverage (thus exempting ethanol from liquor taxes and regulations). This added substance is referred to as a 'denaturant'. For simplicities sake, this study does not model the use of a denaturant and assumes that E100 contains 100% ethanol.

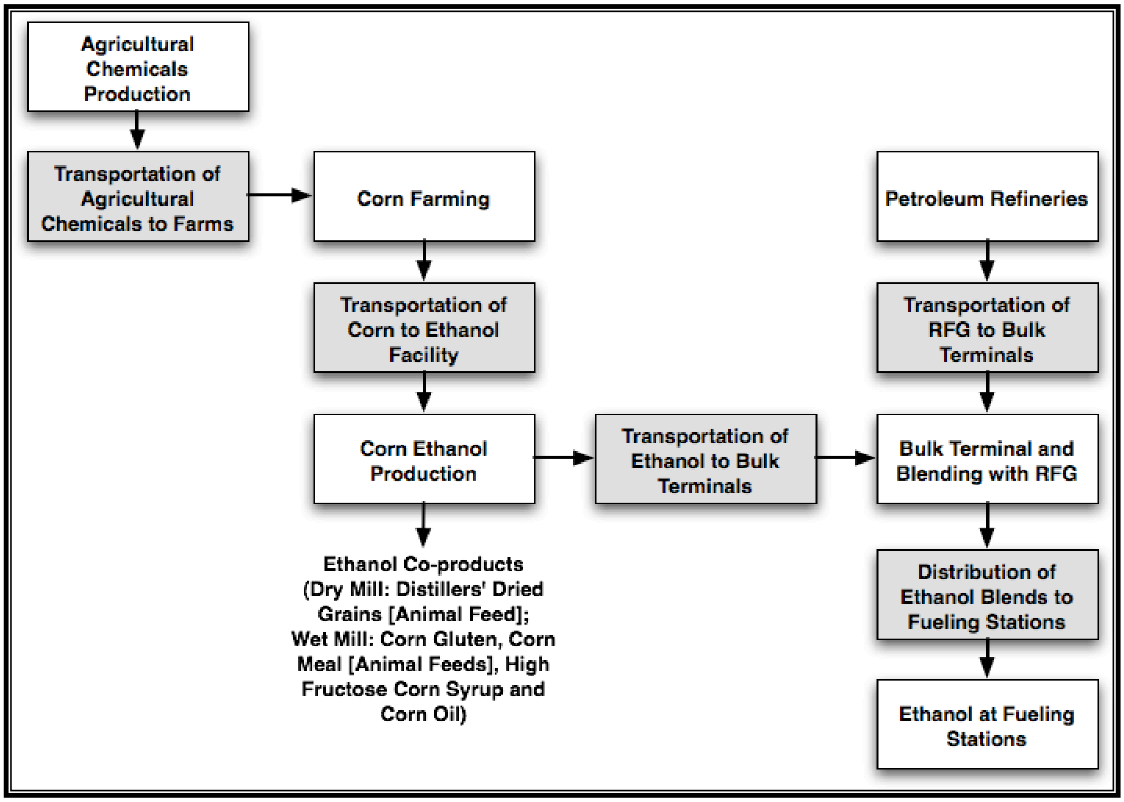

Figure 3-13: Major Stages in Corn Ethanol Production Pathway

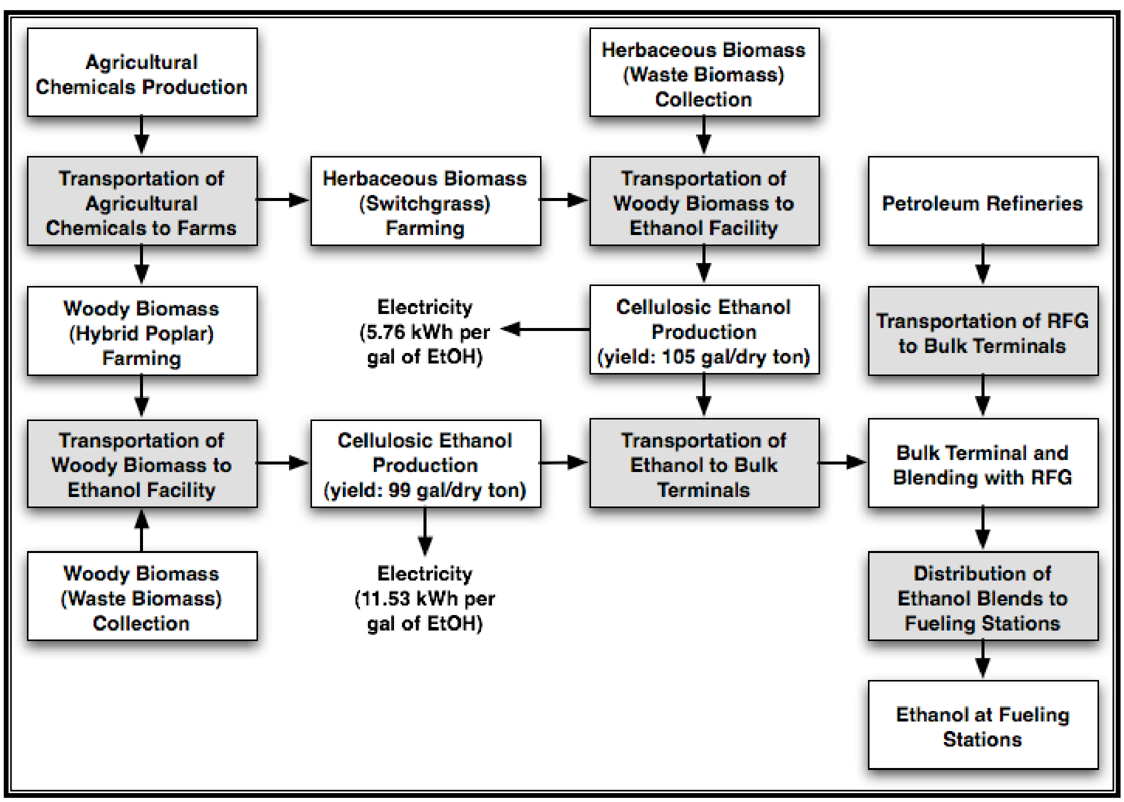

Figure 3-14: Major Stages in Cellulosic Ethanol Production Pathways

A Note on the Ethanol Net-Energy 'Controversy':

With ethanol making up a small but rapidly growing portion of United States' transportation fuels, it is now more important than ever to determine the energy and environmental implications of the production and use biofuels, specifically ethanol produced from corn, as it is currently the most widely consumed and mature of the biofuels considered in this study. As mentioned previously (see Section 1.2), there has been significant public debate in recent years surrounding the net-energy ratio of ethanol from corn. This debate has focused on whether or not ethanol from corn yields more energy than the fossil energy inputs it requires.

Some of this controversy will hopefully be put to rest with the recent publication of a new study performed by a University of California (UC), Berkeley research team that analyzed and examined the methodologies and assumptions of six recent WtW or lifecycle analyses of corn-based ethanol, including two published by Pimentel and Patzek,[127] as well as Wang (1999)/GREET 1.6.[128] The study, published in *Science* in January 2006, concluded that the bulk of the differences between the various studies' results was due to varying methodologies for the treatment of energy and emissions credits allocated to co-products produced during ethanol production (e.g., animal feed, corn oil, etc.).[129] Also, to a lesser degree, several differing assumptions were made about the boundaries of the system – i.e. the inclusion or exclusion of energy embodied in farming machinery and ethanol plants, or the

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[127] See above.
[128] See Farell, Alexander E., et al. "Ethanol Can Contribute to Energy and Environmental Goals". *Science* 311 (Jan 27, 2006): 506-508; and Farell, Alexander E., et al. *Supporting Online Material for: "Ethanol Can Contribute to Energy and Environmental Goals"*. (Berkley, CA: Univ. of California, Berkley, Jan 2006). The study also addresses the analysis of cellulosic biomass from switchgrass performed by Pimentel and Patzek (2005) and Wang (1999)/GREET 1.6.
[129] Farell, et al. (2006a), p. 506.

food energy consumed by farm laborers, etc.[130] The study found that remaining differences between the six studies were due to differing input parameters and sources.[131]

The UC Berkeley study found that the two studies that stood out from the others by concluding that ethanol has a negative net-energy ratio (i.e., Patzek (2004) and Pimentel and Patzek (2005)):

> also stand out from the others by incorrectly assuming that ethanol coproducts (materials inevitably generated when ethanol is made, such as dried distiller grains with solubles, corn gluten feed, and corn oil) should not be credited with any of the input energy and by including some input data that are old and unrepresentative of current processes, or so poorly documented that their quality cannot be evaluated.[132]

The UC Berkeley researchers ultimately constructed their own lifecycle energy and GHG emissions model for corn-based ethanol, as well as cellulosic ethanol from switchgrass, utilizing the best input parameters, assumptions and methodologies from the six studies. This model is referred to as the *E*nergy and Resource Group *B*iofuels *A*nalysis *M*eta-*M*odel, or EBAMM.[133] The UC Berkeley study ultimately concludes "that current corn ethanol technologies are much less petroleum-intensive than gasoline but have greenhouse gas emissions similar to those of gasoline."[134]

As discussed previously (see Section 1.2), focusing on net-ratio alone can be misleading and the author hopes that the several metrics included in this study (i.e. total, fossil and petroleum energy, GHG and criteria pollutant emissions), as well as the easy and objective comparison of ethanol to gasoline and other alternative fuels will provide a more accurate analysis of the merits of ethanol from corn (and the other fuels included in this

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[130] ibid. p. 506.
[131] ibid. p. 506.
[132] ibid. p. 506.
[133] Farell, et al. *ERG Biofuel Analysis Meta-Model* (spreadsheet). (Berkeley, CA: University of California Berkeley, Energy Research Group, January, 2006).
[134] Farell, et al. (2006a), p. 506.

study) than a simple net energy metric.[135] However, this study does provide net (fossil) energy ratios for the various WtP fuel production pathways analyzed so as to allow comparison with other literature. Finally, where possible, this study attempts to utilize the inputs and assumptions included in the EBAMM model developed by the UC Berkley study, as these seem to reflect the most accurate research to date.

3.3.1 Production and Transportation of Agricultural Chemicals

The farming of corn and dedicated woody and herbaceous energy crops involves the use of varying quantities of agricultural chemicals – i.e., fertilizers, herbicides and insecticides. The energy use and emissions associated with the production and transportation of these agricultural chemicals can contribute significantly to the overall WtP energy use and emissions for biomass-based fuels, or biofuels. This study finds that the energy embodied in nitrogen employed as a fertilizer during corn farming contributes over one third of the total energy use associated with the farming of corn, for example.[136]

This study thus models the production and transportation of three types of commonly used fertilizers (nitrogen [N], phosphorous [P_2O_5] and potash [K_2O]) as well as four common herbicides (Atrazine, Metolachlor, Acetochlor, and Cyanazine) and two types of insecticides (one representative of insecticides for application on corn crops and another for use on woody or herbaceous biomass crops). The total energy use and the share of process fuels used in the production of these agricultural chemicals are summarized in Table 3-7 below.

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[135] Other environmental metrics pertinent to the cultivation of energy crops could also be considered, including the effects of soil depletion, chemical run-off, and conversion of forest or grassland into agricultural lands. Unfortunately, such metrics are beyond the scope of this study.

[136] Assumes total farming-rated energy use is 50,277 Btu per bushel (bu) of corn, a nitrogen application rate of 391 g/bu and total energy use associated with the production of nitrogen of 45.9 Btu/g.

Energy use values are based on those reported in the EBAMM model[137] but are decreased by 15% to reflect expected increases in production efficiency by 2025. EBAMM's values represent an analysis of current corn ethanol production-related practices and production efficiencies can be expected to improve by 2025. GREET 1.6 adjusts its short-term (c. 2005) chemical production-related assumptions by 85% to generate its long-term (c. 2016) assumptions. This study thus adjusts EBAMM's short-term values in the same manner to generate the values for 2025 summarized below. Shares of process fuels are based on those published in GREET 1.6.[138]

After production, agricultural chemicals are transported via barge and rail to bulk centers. From there, they are loaded onto trucks and transported to mixing centers before being distributed to farms. The transportation of agricultural chemicals is illustrated in Figure 3-15 below.

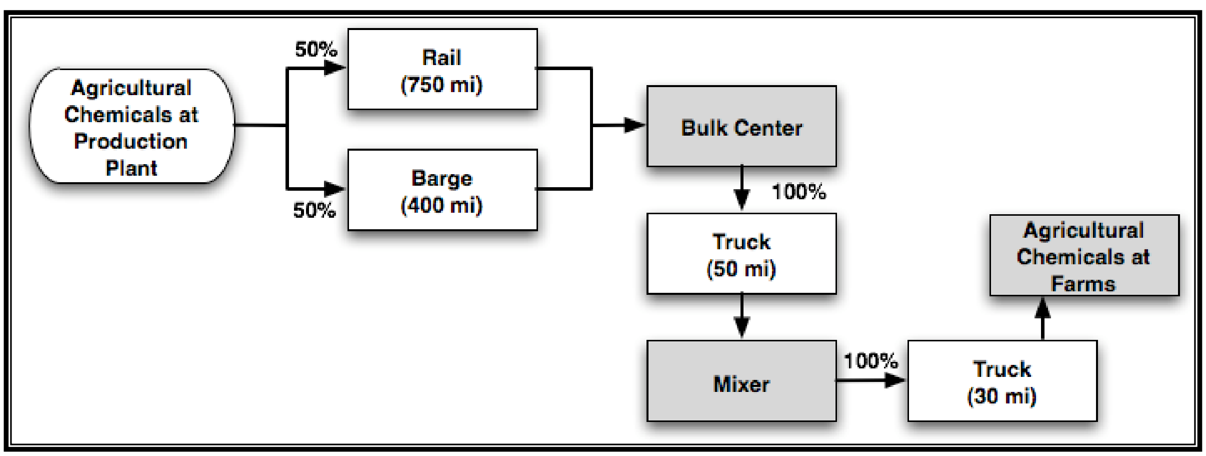

Figure 3-15: Transportation and Distribution of Agricultural Chemicals

[137] Farell, et al. (2006c), *EBAMM*. See 'Ethanol Today' worksheet.
[138] ANL, *GREET 1.6*. See 'Ag_Inputs' worksheet.

Table 3-7: Agricultural Chemicals Production Energy Use and Process Shares

	Total Production Energy Use (Btu/gram of nutrient)	Share of Process Fuels (%) Residual Oil	Diesel Fuel	Natural Gas	Electricity
Fertilizers					
Nitrogen (N)	45.9	0.0%	0.0%	90.0%	10.0%
Phosphorous (P_2O_5)	7.5	0.0%	27.0%	26.0%	47.0%
Potash (K_2O)	5.6	0.0%	31.0%	27.0%	42.0%
Herbicides[139]					
Atrazine	230.0	30.0%	30.0%	23.0%	17.0%
Metolachlor	333.9	30.0%	30.0%	23.0%	17.0%
Acetochlor	336.7	30.0%	30.0%	23.0%	17.0%
Cyanazine	243.7	30.0%	30.0%	23.0%	17.0%
Insecticides					
For corn	288.6	0.0%	60.0%	23.0%	17.0%
For biomass[140]	303.6	0.0%	60.0%	23.0%	17.0%

3.3.2 Farming and Transportation of Corn and Biomass

This study models the farming, harvesting and transportation of corn and biomass feedstocks for the production of biofuels. Switchgrass and hybrid poplar cultivation are selected as representative herbaceous and woody biomass crops, respectively, for use as feedstocks for the production of cellulosic ethanol.[141] For each of these three energy crops, this study attempts to model the energy use and emissions associated with the process fuels used for farming (i.e., diesel fuel, gasoline, natural gas, LPG and electricity) as well as the

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[139] EBAMM does not discuss specific herbicides. This study thus determines individual herbicide values by assuming that the ratio between this study's individual herbicide values and GREET 1.6's long-term individual herbicide values is the same as the ratio between my total corn herbicide value and GREET 1.6's long-term total corn herbicide value.

[140] EBAMM does not report insecticide values for woody biomass (hybrid poplars). This study thus assumes that they are the same as those for herbaceous biomass (switchgrass) as GREET 1.6 does.

[141] Oak Ridge National Laboratory has cultivated these crops in research plots and is studying their potential use as dedicated energy crops as part of the DOE's Biofuels Feedstock Development Program. See Oak Ridge National Laboratory (ORNL). "Biofuels from Switchgrass: Greener Energy Pastures". *Bioenergy Feedstock Information Network*. 1998. <http://bioenergy.ornl.gov/papers/misc/switgrs.html>. Accessed 3/18/2006; and ORNL. "Biofuels from Trees: Renewable Energy Research Branches Out". *Bioenergy Feedstock Information Network*. 1998. <http://bioenergy.ornl.gov/papers/misc/trees.html>. Accessed 3/18/2006.

application of agricultural chemicals.

As Perlack, et al. (2005) reports (see Figure 3-16 below), U.S. agricultural yields have been increasing on average over the past half-century while energy and chemical inputs have remained relatively flat.[142] Wang (1999) reports that corn productivity – the ratio of yields to inputs – increased 30% between 1984 and 1994, for example.[143] Ongoing agricultural research, including the development of more productive varieties of crops and the increasing use of conservation farming techniques (i.e., precision farming, crop rotation and no-till methods), will likely continue this trend into the next two decades for all of the energy crops included in this study.[144] Thus, this study assumes that farming energy use and chemical application rates for all three energy crops decrease 10% by 2025.[145] The farming energy use

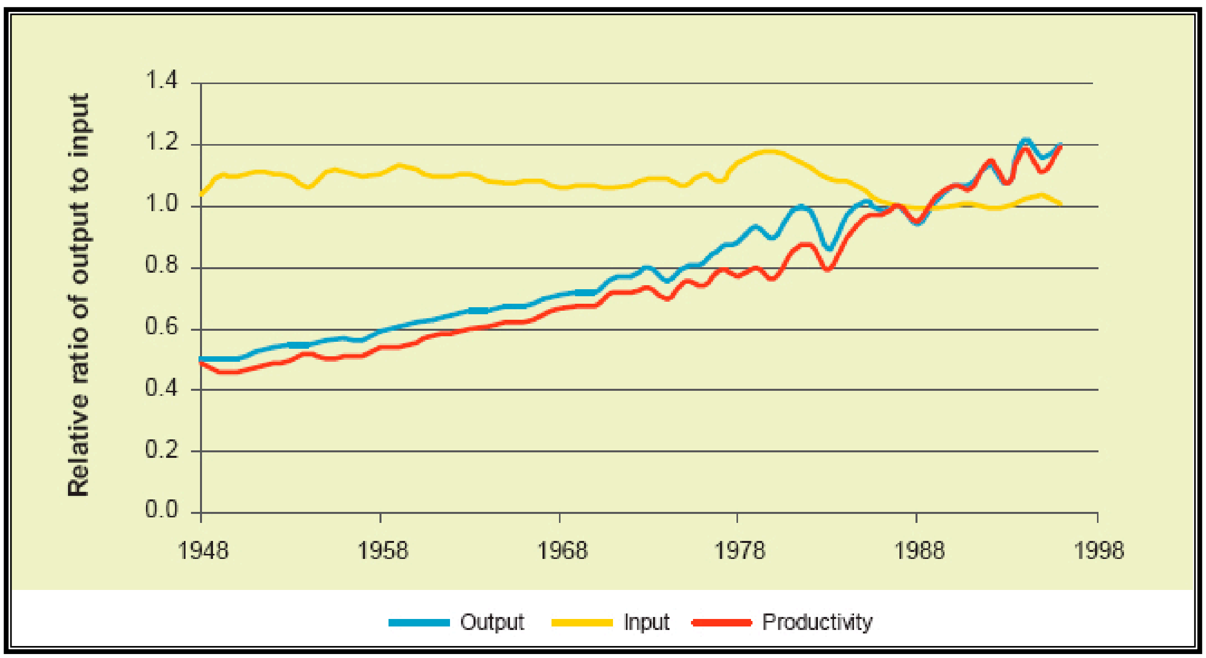

Figure 3-16: Historical U.S. Agricultural Productivity – 1948-1998[146]

[142] Perlack, et al. (2005), p. 20.
[143] Wang (1999), Volume 1, p. 65.
[144] ibid. Volume 1, pps. 64-65.
[145] GREET 1.6 also assumes a 10% decrease between its near-term and long-term time horizons. See ANL, *GREET 1.6*, 'Inputs' worksheet.
[146] Graphic from Perlack, et al. (2005), p. 20.

and chemical applications rates assumed by this study are thus 90% of those published in EBAMM[147] and are summarized in Table 3-8 below. The share of herbicides applied to each crop is summarized in Table 3-9.

In addition to the energy use and emissions embodied in the application of agricultural chemicals and the combustion of process fuels, farming of energy crops results in several non-combustion emissions. These include PM10 emissions during tilling for corn farming and NO_x (NO) and N_2O emissions from the nitrification and denitrification of nitrogen fertilizers used in the farming of all four energy crops. These values are assumed to be the same as those published in GREET 1.6 and are summarized in Table 3-8.[148] Finally, this study also attempts to model CO_2 'emissions' due to land use changes – i.e. the net effect on carbon sequestration in soil and non-harvested biomass due to the cultivation of land for energy crops. The values for net carbon emissions or sequestration due to land use changes are based on those published in the GM, ANL, et al. (2005) WtW study and are summarized in Table 3-8 below.[149]

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[147] See Farell, et al. (2006c), *EBAMM*, 'Ethanol Today' worksheet. GREET 1.6 also assumes that energy use and chemical application rates decrease by 10% between the model's near-term and long-term time horizons. See ANL, *GREET 1.6*, 'Inputs' worksheet.
[148] See ANL, *GREET 1.6*, 'EtOH' and 'BD' worksheets.
[149] See GM, ANL, et al. (2005), p. 24.

Table 3-8: Farming Energy Use, Chemical Application and Non-Combustion Emissions

	Corn Farming (per bushel)	Woody Biomass Farming (per dry ton)	Herbaceous Biomass Farming (per dry ton)
Energy Inputs (Btu/bu or dt)	17,228	211,293	195,507
	Agricultural Chemicals Application (g/bu or dt)		
Nitrogen	391.2	638.1	957.2
Phosphorous (P_2O_5)	166.4	170.1	127.8
Potash (K_2O)	258.4	297.9	203.4
Herbicide	7.25	21.60	25.2
Insecticide	0.55	1.80	0.00
	Non-Combustion Emissions (g/bu or dt)		
PM10 from tillage	20.702	0.000	0.000
NO_x from (de)nitrification	6.622	8.888	133.317
N_2O from (de)nitrification	9.221	11.531	172.971
CO_2 from land use changes	195	-112,500	-48,500

Table 3-9: Share of Herbicides Applied by Crop Type[150]

	Atrazine	Metolachlor	Acetochlor	Cyanazine
Corn	31.2%	28.1%	23.6%	17.1%
Woody Biomass	25.0%	25.0%	25.0%	25.0%
Herbaceous Biomass	25.0%	25.0%	25.0%	25.0%

After farming and harvesting, corn and biomass are shipped to ethanol production plants via trucks. The transportation of energy crops over long distances often becomes prohibitively expensive. For example, a 1999 Oak Ridge National Laboratory study estimates that delivering herbaceous biomass to cellulosic ethanol plants or biomass-fired power plants costs between 5 and 10 cents per ton per mile,[151] while a 2005 study by the U.S. Departments of Agriculture and Energy reports that woody biomass can be transported at a cost between 20 and 60 cents per ton per mile.[152] Corn transportation costs are similar to

[150] Shares of herbicides as per ANL, *GREET 1.6*, see 'Ag_Inputs' worksheet.
[151] Walsh, Marie E., et al. "Biomass Feedstock Availability in the United States: 1999 State Level Analysis". April 30, 1999 (updated Jan. 2000). <http://bioenergy.ornl.gov/resourcedata/index.html>. Accessed 5/13/2006.
[152] Perlack, et al. (2005). p. 34.

those for herbaceous biomass. Thus, at distances greater than around 50 miles, delivery costs for the energy crop begin to dominate the cost of the crop itself.[153] For these reason, ethanol plants must be located relatively close to the source of energy crop feedstock. This study thus assumes that corn and woody and herbaceous biomass are transported only 50 miles on average to reach the ethanol plant. This simple transportation flow is described in Figure 3-17 below.

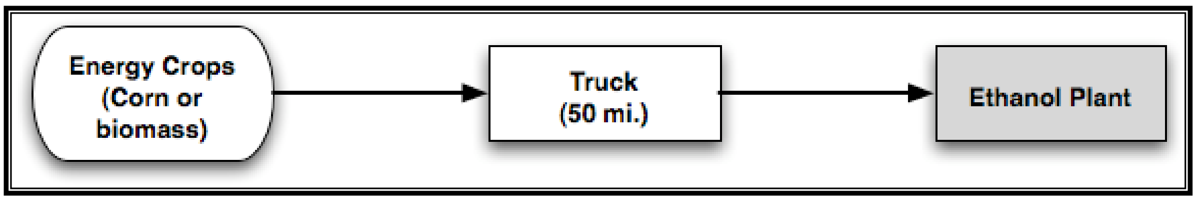

Figure 3-17: Transportation of Energy Crops for Biofuel Production

3.3.3 Recovery and Transportation of Waste Biomass

In addition to switchgrass and hybrid poplar stands cultivated for use as dedicated energy crops, this study considers the use of 'waste' biomass as a feedstock for the production of cellulosic ethanol. 'Waste' biomass refers to potentially recoverable biomass that is the result of some other intended process and includes forestry wastes (principally logging residues, mill residues, and pulping liquors), agricultural wastes (crop residues such as corn stover and wheat straw, animal manures, etc.), and urban wood residues (principally municipal solid waste and construction waste). This study also includes woody biomass from thinning for fuel treatment (fire risk management) of timber and forestland amongst the available waste biomass.

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[153] At 20-30 cents per dry ton per mile, perhaps a representative transportation cost value for a mix of herbaceous and woody biomass, transporting the feedstock 50 miles costs $10-15 per ton, roughly equal to the $10-15 per dry ton cost that Walsh, et al. (1999) estimates for agricultural residues.

The recent USDA and DOE study on the available supply of biomass for bioenergy and bioproducts industries[154] concluded that a significant supply of waste biomass could be sustainably harvested for use as bioenergy feedstock. The study concluded that 268 million dry tons of forestry waste (including 60 million dry tons from fuel treatment thinning), 533 million dry tons of agricultural waste and 47 million dry tons of urban wood waste could be sustainably recovered each year for use as bioenergy feedstocks by mid-century, for a total of 848 million dry tons per year.[155] Thus, by 2025, a sizable amount of waste biomass on the order of several hundred million dry tons per year could be available for use as a feedstock for cellulosic ethanol production. In contrast, the USDA/DOE study concluded that only 87 million dry tons of corn and other grains could be sustainably harvested for conversion to ethanol, while a more sizable 377 million dry tons of perennial herbaceous biomass crops and fast growing trees could be harvested each year for bioenergy feedstocks.[156] The total available biomass resources by source reported by the USDA/DOE study are summarized in Figure 3-18 below.

The use of waste biomass as a bioenergy feedstock is not included in the GREET model. As such, this study modifies GREET to include a waste biomass-to-ethanol pathway. While recovering waste biomass would certainly consume some quantity of process fuels (i.e. diesel fuel for collection equipment, etc.) that would not be used if the waste biomass were not collected, this study was unable to find any estimates of average energy use for waste biomass collection in any available literature. Quantifying the amount of energy used (and associated emissions) for collecting waste biomass is also difficult due to the fact that waste biomass can come from a variety of different sources, each with differing collection

[154] See Perlack, et al. (2005).
[155] ibid. p. 35.
[156] ibid. p. 35.

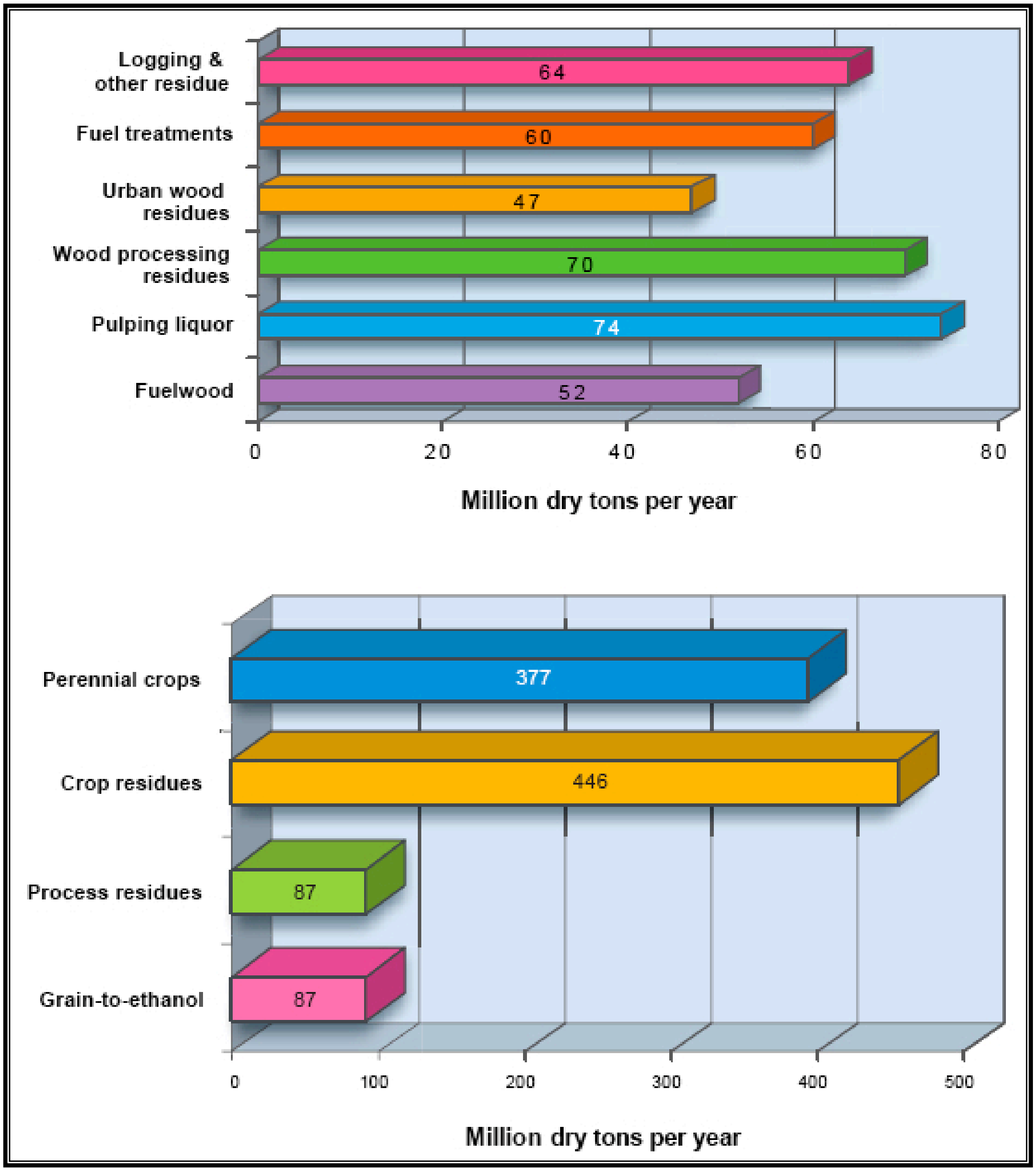

Figure 3-18: Summary of USDA/USDOE Estimates of Available Biomass for Use as Bioenergy Feedstock[157]

techniques and processes. Some waste feedstocks, forestry waste, for example, would likely require larger energy inputs as the waste biomass is dispersed and located far from main

[157] Graphic from ibid. p. 35

transport infrastructure, while others, such as mill residues, may require very little in the way of energy inputs for collection (mill wastes are concentrated in one place and located near transport infrastructure). Furthermore, some methodology should be constructed to determine the appropriate split of energy use and emissions associated with primary processes (i.e. wood product manufacture or food crop harvesting) and the waste biomass now utilized as a bioenergy feedstock. Unfortunately, the development of a detailed methodology for allocating energy use and emissions associated with the recovery of waste biomass is beyond the scope of this study. As the bioenergy industry develops and an increasing quantity of waste biomass is harvested, it will become increasingly important to develop a more accurate estimate of the energy and environmental impacts of waste biomass recovery, and this presents one opportunity for the continued refinement of this study's methodologies.

In any case, the energy use and emissions associated with the collection of waste biomass is likely much less than the energy use and emissions associated with farming and harvesting a similar quantity of biomass as a dedicated energy crop. It is thus worthwhile to attempt to model a waste biomass-to-ethanol pathway in some manner. In the absence of reliable data and a more robust methodology, this study simply assumes that waste biomass consumes 10% more energy in the transportation stage than biomass from dedicated energy crops. Like dedicated energy crops, waste biomass cannot be cost-effectively shipped over long distances and this study assumes that waste biomass travels only 50 miles on average to reach a cellulosic ethanol plant. The resulting transportation energy use and emissions are then increased by 10% to attempt to approximate the energy use and emissions due to the collection of the waste biomass before transport. The simple transportation flow diagram for waste biomass-to-ethanol pathways is summarized in Figure 3-19 below.

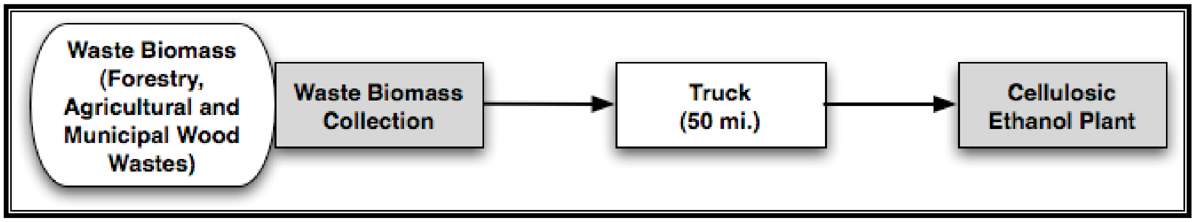

Figure 3-19: Transportation of Waste Biomass for Cellulosic Ethanol Production

3.3.4 Biofuel Production, Transportation and Distribution

This study models the production of ethanol from corn at wet and dry mill ethanol plants as well as the production of ethanol from woody and herbaceous biomass at cellulosic ethanol plants. These processes are discussed in this section, along with the subsequent transportation and distribution of the resulting biofuels.

Co-product Allocation Methodologies

All of various ethanol production processes described in this section produce one or more useful co-products in varying amounts. Corn ethanol production, for example, co-produces marketable quantities of various animal feeds as well as corn oil and corn syrup (depending on the type of mill), while the production of cellulosic ethanol co-produces significant quantities of electricity for export. As these co-products are valuable and marketable products, the energy use and emissions associated with the production process, as well as those associated with the 'upstream' production and transportation of feedstocks should be split in some proportion amongst the primary product (i.e., ethanol) and the one or more valuable co-products. There are several methodologies for allocating energy use and emissions credits associated with co-products resulting from these ethanol production processes and applying different methodologies can often yield very different results.

This study includes three different co-product allocation methods for various processes: the Displacement or Offset Method, the Energy Content Method, and the Market Value Method.[158] Some methods may be more appropriate in certain circumstances or my be more or less useful depending on the desired end use for the resulting WtP energy and emissions values. In most cases, this study calculates WtP energy use and emissions using two different methodologies potentially appropriate for that process so as to demonstrate the effects of various co-product allocation methods and to allow the reader to select the methodology deemed most appropriate for his or her uses.

The Displacement (or offset) Method assumes that since co-products have a positive market value, they will displace other products on the market that also require energy and produce emissions to manufacture. The Displacement Method thus attempts to determine the energy use and emissions embodied in the displaced products and then subtracts that amount from the energy use and emissions for the biofuel production process and upstream stages. Distillers' dried grains and solubles (an animal feed) produced during corn ethanol manufacture at dry mills is thus assumed to offset the use of corn and soybean meal, for example.

The Displacement Method is generally the technically correct method for allocating credits for co-products. However, it is often difficult to accurately predict which products will be displaced and determine the appropriate displacement ratio between the co-products

[158] Other methods include the process method in which a process simulation model is developed to determine mass and energy flows through the production process which is then used to allocate process energy and emissions to the appropriate end products.

and the products they displace. A full life-cycle analysis of each displaced product is also necessary and the Displacement Method is further complicated by the fact that product displacement will generally not scale linearly. At some point, for example, an increase in corn meal production from wet mill ethanol plants may simply result in an increased consumption of animal feeds (due to lower market prices) rather than a displacement of other animal feeds such as soybean meal.

Finally, for some processes, the use of the Displacement Method may result in negative net energy use and emissions values for the production process. For example, using the Displacement Method to assume that the significant quantities of electricity co-produced at cellulosic ethanol plants offsets electricity from the average U.S. electricity mix (which is dominated by coal-fired power plants and is relatively fossil energy and emissions intensive), results in negative net values for fossil energy, GHG emissions and emissions of certain criteria pollutants associated with cellulosic ethanol production. While this may be deemed an appropriate way to consider the effects of expanded electricity production from cellulosic ethanol plants, it may also be considered inappropriate for comparison to other processes.

Neither the Energy Content Method, nor the Market Value Method can produce negative net values and may be more appropriate (and easier to calculate) than the Displacement Method. The Energy Content Method can be applied when both the primary product and the co-products are all energy products – i.e. fuels, heat, steam, electricity, etc. In these cases, the energy use and emissions associated with the production of the products and associated upstream processes can be allocated to each end product proportionate to the energy content of the product.

The Market Value Method is similar, but allocates the upstream and production process energy use and emissions proportionate to the market value of each of the end products. The Market Value Method can be applied to any marketable co-products, but it is often difficult to accurately determine the appropriate market price. Market prices vary over time and it is thus necessary to examine historical market trends and determine an average representative market price for each product. Additionally, the increased production of a co-product will likely have a non-linear affect on market prices (i.e. a market glut may be created, lowering prices), which may also be difficult to accurately predict.

There does not seem to be any clear consensus in the literature as to which co-product allocation method is the most accurate.[159] However, Wang (1999) and Farell, et al., the authors of the EBAMM model and related study, both conclude that the Displacement Method is generally the most appropriate. This model includes all three methods and utilizes them for different processes modeled by the study. When possible, two different allocation methods are employed so as to illustrate the sensitivity to co-product allocation methods. In general, this study agrees with Wang and Farell, et al. and considers the Displacement Method the most accurate. However, when the co-product allocation method results in net negative energy or emissions values (i.e. for the cellulosic ethanol production process), this study considers a more conservative Energy Content or Market Value Method more appropriate.

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[159] See Farell, et al. (2006b), pps 8-10.

Ethanol Production from Corn:

Ethanol production from the fermentation of corn starch occurs in both 'wet' and 'dry' mill plants. Wet mill plants are larger and more capital intensive than dry mill plants and are integrated biorefineries producing ethanol from corn starch as well as a variety of useful co-products including high fructose corn syrup, corn gluten feed, corn meal feed, and corn oil. Dry mill plants are smaller than wet mill plants and are designed solely for ethanol production. Dry mill plants produce only one co-product, distillers' dried grains and solubles (DDGS), which is suitable for use as animal feed.[160]

The ethanol production phase is by far the most fossil-fuel intensive portion of the corn-to-ethanol production pathway. Currently operating wet mill ethanol plants rely largely on coal for process energy due to its lower cost, relative to natural gas. Coal is typically burned to co-generate process steam and electricity, while natural gas is used for the direct drying of products due to the higher heat demand for these processes.[161] Wang (1999) reports that 80% of the thermal process energy required at currently operating ethanol plants is derived from coal, while the remaining 20% comes from natural gas.[162] Dry mill plants are smaller and thus have less of a cost savings incentive to switch to coal for thermal energy. Thus, Wang (1999) conservatively assumes that 50% of thermal process energy for current dry mill ethanol plants comes from natural gas, while the remainder comes from coal.[163] However, increasingly restrictive environmental regulations have denied permits for coal burning to many recently constructed ethanol plants, and this trend can be expected to

[160] See Wang (1999). Volume 1, p. 70.
[161] ibid. Volume 1, p. 71.
[162] ibid. Volume 1, p. 71.
[163] ibid. Volume 1, p. 71.

continue in the future.[164] Thus, this study assumes, as does GREET 1.7b, that by 2025, only 40% of the energy used in wet mill plants will come from coal while coal will provide just 20% of the energy for dry mill plants.[165]

After analyzing the available literature, Farell, et al. (2006a) and their EBAMM model conclude that the USDA's latest assessment of the net energy balance of corn ethanol (i.e., Shapouri, et al. (2004))[166] reports the most accurate values for the energy intensity of corn ethanol production. The USDA study relies on the latest (2001) survey of U.S. ethanol manufacturers and reports that dry mill plants consume 34,700 Btu of coal and natural gas and 1.09 kWh (3,719 Btu) per gal of ethanol produced (for a total of 38,419 Btu/gal).[167] The study reports that wet mill plants consume 49,208 Btu of coal and natural gas per gallon and co-generate all of their process electricity on site.[168] This study thus bases its assumptions for the energy intensity of ethanol production on the values published in Shapouri et al. (2004) and corroborated by EBAMM and Farell, et al. (2006a).

While nearly all wet mill plants employ co-generation, many dry mill plants purchase power from the grid. Wang (1999) estimates that approximately half of currently operating

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[164] ibid. Volume 1, p. 71.
[165] See ANL, *GREET 1.7 Beta,* 'Fuel_Prod_TS' worksheet.
[166] Shapouri, Hosein, et al. *The 2001 Net Energy Balance of Corn Ethanol.* (Washington D.C.: US Department of Agriculture, 2004).
[167] ibid. p. 5.
[168] ibid. p. 5. Wang (1999) and GREET 1.6 seem to underreport the energy intensity of wet mill ethanol production. Wang (1999) reports an energy intensity of 34,000 Btu/gal EtOH (see p. 70), while GREET 1.6's default short-term value is 37,150 (see 'EtOH' worksheet), both considerably lower than Shapouri, et al. (2004)'s values. Both values are also lower than the corresponding dry mill energy intensities, the opposite of the case in other literature. This discrepancy could be because Wang (1999) does not include high fructose corn syrup produced at wet mill plants amongst the plant's co-products, while Shapouri, et al. (2004) and other literature do. Wang (1999) writes, "Production of high fructose corn syrup, a high-value end product derived from corn kernel sugars, takes place in a different process stream and is therefore not included as an ethanol coproduct" (p. 70). GREET 1.7b assumes a much higher value for wet mill energy intensity, 46,000 Btu/gal, (see 'Fuel_Prod_TS' worksheet), but this is still noticeably lower than Shapouri, et al (2004). It is unclear what assumptions are made regarding high fructose corn syrup in either GREET 1.6 or 1.7b and in the absence of clearer documentation, this study bases its assumptions on the more conservative values reported by Shapouri, et al. (2004) and corroborated by Farell, et al. (2006a) and EBAMM.

dry mill plants employ co-generation, while the other half rely on purchased electricity. Dry mill plants employing co-generation could easily achieve a reduction of 10% in total energy use,[169] and this study assumes that by 2025, all dry mill plants employ cogeneration, resulting in a 5% decrease in the average energy intensity of dry mill ethanol plants. Additionally, the expanded use of co-generation at dry mill plants means that by 2025, this study assumes that none of the process energy for dry mill plants is supplied by purchased electricity. Furthermore, this study also assumes an additional 5% decrease in energy intensity for both dry and wet mill plants by 2025, representing likely increases in process efficiency. Thus, this study assumes that, by 2025, the process energy intensities for ethanol production are 34,577 Btu/gal for dry mill plants (a 10% decrease from Shapouri, et al (2004)'s figures) and 46,748 Btu/gal for wet mill plants (a 5% decrease from Shapouri, et al. (2004)).

In addition to process-related combustion emissions, ethanol production results in the non-combustion emissions of VOC (from the evaporation or spillage of ethanol) and PM10. This study assumes, as per GREET 1.6, that ethanol production at both dry and wet mills results in the non-combustion emissions of 2.239 grams of VOC and 0.856 grams of PM10 per gal of ethanol.[170]

According to the GM, ANL, et al. (2005) WtW study, in recent years most of the newly constructed corn ethanol production capacity in the United States has been in the form of dry mill plants.[171] This is because of the lower capital expenses and shorter construction times of dry mill plants relative to wet mill plants. Thus, in 2004, approximately 75% of total U.S. corn ethanol was produced in dry mill plants, according to GM, ANL, et al.

[169] Wang (1999) reports that co-generation could achieve reductions in energy use as high as 30%, while 10% are easily achievable. See Volume 1, p. 71.
[170] See ANL, *GREET 1.6*, 'EtOH' worksheet.
[171] GM, ANL, et al. (2005), p. 22.

(2005).[172] However, this study assumes, as the GM, ANL, et al. (2005) study does,[173] that in the coming decades, additional wet mill ethanol plants will be constructed, bringing their share of total U.S. corn ethanol production capacity to 30% by 2025.

In addition to improvements in energy intensity, the yield (i.e., gallons of ethanol produced per bushel of corn input) for ethanol plants is likely to increase moderately in the future as well. This study thus assumes, as per GREET 1.7b,[174] that yields will improve from approximately 2.7 gal/bushel (bu) of corn for dry mill plants and 2.6 gal/bu for wet mill in 2005 to 2.8 and 2.7 gal/bu for dry and wet mill plants, respectively, by 2025. GREET 1.6 uses either the Displacement Method, or the Market Value Method (as discussed above) to allocate energy use and emissions for ethanol production and associated upstream stages amongst ethanol and the various ethanol co-products. This study reports WtP results for corn ethanol using both co-product allocation methods, although it favors the displacement method as more accurate.

Ethanol Production from Herbaceous and Woody Biomass:

Two main processes are in development that produce ethanol from a variety of sources of woody and herbaceous biomass. These processes are distinguished from traditional ethanol production methods that ferment sugar or starch crops into ethanol (including the corn-to-ethanol process described above) in that they instead convert cellulose, which makes up the bulk of all plant matter, into ethanol. The resulting fuel is referred to as cellulosic ethanol, although it is chemically identical to ethanol produced in traditional methods. The principle advantage of cellulosic ethanol production processes is that they

[172] ibid. p. 22.
[173] See ibid. p. 22.
[174] See ANL, *GREET 1.7 Beta*, 'Fuel_Prod_TS' worksheet.

enable a wide variety of feedstocks including dedicated perennial energy crops (i.e. switchgrass, etc.) and fast growing trees (hybrid poplars and willows) as well as organic cellulose-rich wastes (including forestry, agricultural and urban wood wastes). Additionally, such feedstocks are not edible food crops, as in the case of traditional ethanol processes, which rely on corn or grain and directly compete with markets for food crops.

Two North American companies have developed cellulosic ethanol production technologies at the pilot-scale and are currently attempting to develop full-scale commercial plants. In 2004, the Canadian company, Iogen Corp., became the first in the world to commercially sell ethanol derived from cellulosic biomass.[175] Iogen uses a steam explosion pretreatment process to increase the surface area of cellulosic feedstocks in order to ready them for further processing by specially engineered cellulase enzymes. These enzymes are tailored to a specific feedstock (i.e., straw, corn stover, switchgrass, etc.) and convert the cellulose in the feedstock to sugars (glucose) that can be fermented into ethanol. This step in the process is known as 'enzymatic hydrolysis' and is followed by the separation of the resulting glucose from the remaining lignin portion of the feedstock. The lignin, which is impervious to the enzymes, can then be combusted to generate process heat and steam, as well as electricity for export. Finally, the separated glucose can be fermented to produce ethanol using the same kind of fermentation process found in traditional ethanol plants.[176] Iogen's process currently works only on straw and the company is working to develop

[175] See Iogen, Corp. "Cellulose Ethanol is Ready to Go". *News*. April 21, 2004. <http://www.iogen.ca/news_events/press_releases/2004_04_21.html>. Accessed 5/16/2006. As this study is written, Iogen just received a $30 million investment from major Wall Street investment firm Goldman Sachs. See <http://www.iogen.ca/news_events/press_releases/2006_05_06.html>.
[176] See Iogen, Corp. "Process". *Cellulose Ethanol*. 2005. <http://www.iogen.ca/cellulose_ethanol/what_is_ethanol/process.html>. Accessed 5/16/2006.

enzymes for use with a variety of other feedstocks. This process is representative of fermentation-based cellulosic ethanol production processes.

One of the main barriers to fermentation-based processes is the cost of the specially tailored enzymes needed to convert the cellulose to sugars, as a constant stream of these enzymes must be maintained to enable fermentation-based cellulosic ethanol production. As such, the DOE's Biomass Program has contracted with the world's two largest enzyme producers, Genencor International and Novozymes, to significantly reduce cellulase costs for use in cellulosic ethanol production. The DOE reports that as of 2004, both companies had already achieved a 10-fold reduction in the cost of the enzymes since 2000, when the contracts began. Enzyme costs are now effectively $0.50 per gallon of ethanol, but continued development is needed to bring costs down to the DOE's target of $0.10 per gal.[177]

Arkansas-based BRI Energy, LLC, is developing a different kind of cellulosic ethanol production process. In contrast to Iogen's fermentation process, BRI's process is representative of a gasification-based process[178] and does not rely on the conversion of cellulose to sugars. BRI's process, which has been demonstrated at a pilot-scale, converts cellulosic biomass into a carbon-rich synthesis gas, or 'syngas' through a process known as gasification. Gasification is the result of the partial combustion of carbon-rich organic matter in a pressurized chamber in the presence of controlled amounts of oxygen or air. The resulting syngas consists mostly of carbon monoxide (CO) and hydrogen (H_2). The key to BRI's process is a microorganism, named *Clostridium ljungdahlii,* which ingests (eats) CO in

[177] See Energy Efficiency and Renewable Energy, Office of. "Cellulase Cost-Reduction Contracts." *Technologies*. Jan. 20, 2006. <http://www1.eere.energy.gov/biomass/cellulase_cost.html>. Accessed 5/16/2006.

[178] Gasification-based cellulosic ethanol production processes are discussed in detail in the following paper: Morrison, Christine, E. *Production of Ethanol from the Fermentation of Synthesis Gas*. (Mississippi State, MS: Mississippi State Univ, Aug. 2004).

the syngas and produces ethanol and water. The resulting ethanol is distilled or separated from the water and the remaining hydrogen from the syngas. In addition to producing ethanol, this process produces a significant amount of waste heat – the syngas leaves the gasifier at over 2,000° C and must be cooled to 100° C before being fed to the microorganisms – which can be used to create steam and generate electricity with a steam turbine. The turbine exhaust steam can also be used for process heat for ethanol purification, feedstock drying and air-preheating, etc. Furthermore, the residual hydrogen-rich syngas remaining after ethanol production can be combusted to produce more electricity. Alternatively, the hydrogen can be separated and marketed.[179]

One of the main advantages of gasification-based processes, such as BRI's, is that they can accept a wide variety of feedstocks and are not limited by feedstock-specific enzymes, as fermentation-based processes are. For example, BRI recently announced plans to construct two gasification-based cellulosic ethanol plants in Oak Ridge, Tennessee. One plant would use coal as a feedstock while the other would use municipal solid waste.[180] These plants could be constructed by the end of the decade.

GREET 1.6 includes a cellulosic ethanol production process representative of the slightly more mature fermentation-based process. GREET 1.7 will include a gasification-based pathway as well, although at this time, it is not completed in the beta version of the model. This study thus models a fermentation-based cellulosic ethanol production process. However, the process modeled by this study is representative of a more advanced process that could become commercialized by 2025. This process is intended to represent the advanced bio-ethanol and gas turbine combined cycle plant described in detail in a 2005

[179] See BRI Energy, LLC. "Technology Summary". *BRI Energy Process*. March 18, 2006. <http://www.brienergy.com/pages/process01.html>. Accessed 5/16/2006.
[180] See <http://www.knoxnews.com/kns/local_news/article/0,1406,KNS_347_4664543,00.html>

report from ANL's Center for Transportation Research (i.e., Wu, et al. (2005)).[181] This advanced ethanol plant uses an ammonia fiber explosion pretreatment process to ready the feedstock for enzymatic hydrolysis. The resulting sugars are then separated from the lignin and fermented, as in Iogen's fermentation process, described above. The resulting wastewater is treated in an on-site wastewater treatment plant where it undergoes anaerobic and aerobic fermentation, producing methane gas. This gas is collected for later use in the on-site power plant. The main difference between this advanced process and the one employed by Iogen is that after fermentation, the remaining lignin, along with solid residues and sludge from the water treatment plant are used as feedstock for a biomass gasification power plant. The lignin and solid residues are gasified and the resulting syngas is cleaned and then mixed with methane from the water treatment plant and used as fuel for a combined cycle power plant (see Section 3.4.2 below for more on combined cycle and biomass gasification power plants). This results in the production of significant quantities of electricity, as well as all of the process heat and steam necessary for the ethanol production process.[182] In this kind of process, electricity for export is no longer a minor by-product, but rather a major co-product of this integrated advanced ethanol production and gas turbine power plant facility.

The ethanol plant described by Wu, et al. (2005) is designed to use herbaceous biomass (switchgrass) as a feedstock. This study thus bases ethanol and electricity yields for the herbaceous biomass-to-ethanol process on those published in Wu, et al. (2005). This study assumes, as per Wu, et al. (2005), that this plant has a yield of 105 gallons of ethanol

[181] Wu, May, Ye Wu, and Michael Wang. *Mobility Chains Analysis of Technologies for Passenger Cars and Light-Duty Vehicles Fueled With Biofuels: Application of the GREET Model to the Role of Biomass in America's Energy Future (RBAEF) Project*. (Argonne, Il: Argonne National Laboratory, May 2005).
[182] See Wu, et al. (2005), p. 6.

per dry ton of herbaceous biomass and co-generates 5.76 kWh of electricity per gallon of ethanol produced.[183]

The woody biomass-to-ethanol process modeled by this study is assumed to use the same integrated advanced ethanol production and gas turbine power plant facility as for the herbaceous biomass. However, due to the different cellulose and lignin contents of woody and herbaceous biomass, ethanol and electricity yields will be different when woody biomass is the feedstock than when herbaceous biomass is used. This study assumes that woody biomass ethanol plants yield 100 gallons of ethanol per dry ton of woody biomass, as per the assumptions for woody biomass-fed fermentation plants published in GREET 1.7b.[184] Furthermore, this study assumes that the woody biomass-to-ethanol process yields 11.53 kWh per gallon of ethanol produced.[185]

The combustion emissions associated with these cellulosic ethanol production processes are assumed to be the same as for the biomass-fired integrated gasification combined cycle plant modeled by this study (see 3.4.2 below). Note that the CO_2 released during combustion of biomass was originally absorbed from the atmosphere during plant photosynthesis. Thus, combustion-related CO_2 emissions are treated as zero for the combustion of biomass. Additionally, as per GREET 1.6, this study assumes that cellulosic ethanol production results in non-combustion VOC emissions equal to half those of a dry mill ethanol plant (i.e. 1.12 g/gal EtOH) and PM10 equivalent to a dry mill plant (i.e. 0.856

[183] See Wu, et al. (2005), p. 11.
[184] See ANL, *GREET 1.7 Beta*, 'Fuel_Prod_TS' worksheet. Note that the ratio between yields from woody and herbaceous biomass is roughly equal to the cellulose/hemicellulose contents of the two varieties of biomass (woody: 59%; herbaceous: 63%).
[185] This assumes that the ratio between electricity yields from woody and herbaceous biomass are the same as the ratio between GREET 1.6's default parameters for electricity yields (i.e. ~2:1). See ANL, *GREET 1.6*, 'Inputs' worksheet.

g/gal EtOH).[186]

This study calculates energy use and emissions credits for the electricity co-produced during cellulosic ethanol production using both the Displacement Method and the Energy Content Method (as discussed above). For the Displacement Method, this study assumes that the electricity produced by the cellulosic ethanol plant offsets an equal amount of electricity from the average electricity mix. Since the average U.S. mix is heavily fossil fuel dependent and is dominated by coal-fired power plants that emit large quantities of GHGs and several criteria pollutants (see Section 3.4.2 below), using the Displacement Method here actually results in negative WtP fossil and petroleum energy values as well as negative values for GHG emissions and several criteria pollutants, especially when waste biomass is used as a feedstock. That is, the fossil and petroleum energy use and emissions of GHGs and several pollutants associated with the production of the electricity from the U.S. average mix offset by electricity co-produced at the cellulosic ethanol plant are actually larger than those values associated with the entire cellulosic ethanol fuel production pathway.

While these results point to the importance of replacing coal and other fossil-generated electricity in U.S. electricity mix, they may unfairly bias comparisons with the other fuels considered in this study. The primary focus of this study is on the replacement of petroleum-based transportation fuels, not on the effects of fuel production processes on the electricity generation sector. As such, it may be more appropriate to consider the WtP results for cellulosic ethanol calculated using the Energy Content Method. This study thus includes results calculated using both co-product allocation methods.

[186] See ANL, *GREET 1.6*, 'EtOH' worksheet.

Ethanol Transportation and Distribution:

After production at corn or cellulosic ethanol plants, ethanol is transported via barge and rail and truck to bulk distribution terminals. There, it is blended in varying amounts with reformulated gasoline (RFG), both as an oxygenate for RFG (i.e. 5.7% ethanol by volume) and as ethanol fuel blends (i.e. E85, or 85% ethanol by volume). After blending, ethanol is loaded onto tanker trucks for distribution to fueling stations. The transportation and distribution of ethanol is described in Figure 3-20 below.

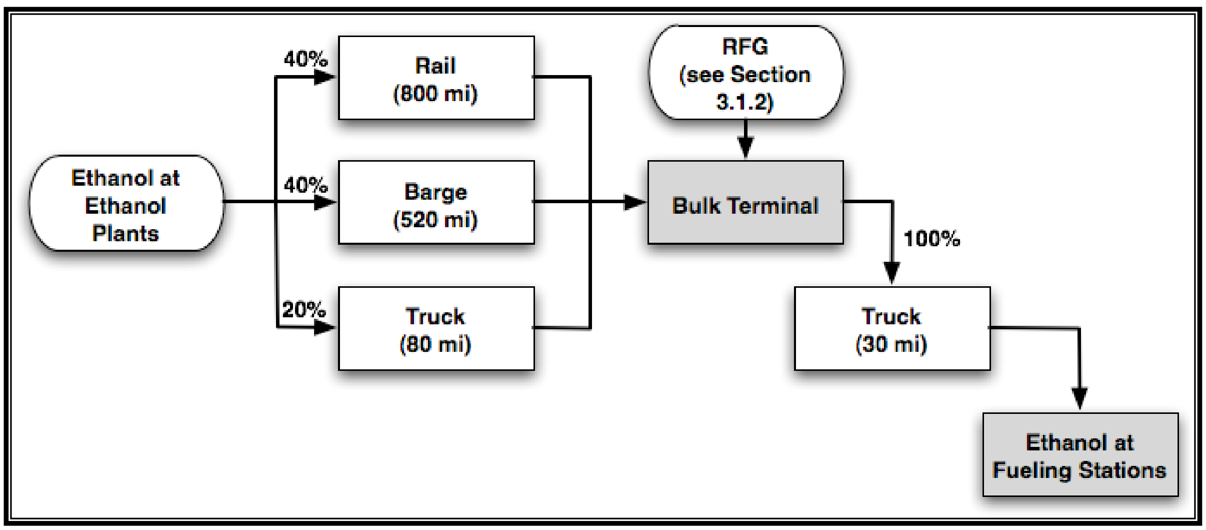

Figure 3-20: Transportation and Distribution of Ethanol

3.3.5 Summary of Energy Use and Emissions Assumptions and Results for Biomass-based Fuel Production Pathways

Table 3-10 below summarizes the major assumptions used to calculate energy use and emissions for the biomass-based fuel pathways described above. Table 3-11 summarizes energy use and emissions results for biomass-based WtP fuel production stages. Additionally, several of the fuel production pathways considered in this section are combined with the electricity pathways discussed in Section 3.4 to model combined WtP fuel pathways for plug-in hybrid electric vehicles. These WtP results are presented in Table 3-17 in Section 3.4 below. Note that biomass-based fuels are given a CO_2 'credit' for the amount of CO_2 contained in the fuel that is derived from biomass, as this CO_2 was absorbed from the atmosphere during plant photosynthesis. Thus, the WtP fuel pathways below show negative values for WtP CO_2 emissions.

Table 3-10: Key Assumptions for Biomass-based Fuel Production Pathways

Assumption	***Value***
Agricultural Chemicals Production and Transportation	
Agricultural Chemicals Production Energy and Process Shares	See Table 3-7
Share of agricultural chemicals transported by mode (%)*	
Barge	50.0%
Rail	50.0%
Truck (to mixing station)	100.0%
Truck (to farm)	100.0%
Average trip distance for agricultural chemicals by mode (mi)	
Barge	400
Rail	750
Truck (to mixing station)	50^
Truck (to farm)	30^
Corn and Woody and Herbaceous Farming and Transportation	
Farming energy intensities	See Table 3-8
Agricultural chemicals application rates	See Table 3-8
Share of Herbicides	See Table 3-9
Non-combustion Emissions	See Table 3-8
Share of energy crop transported by mode (%)*	
Truck	100.0%
Average trip distance for energy crop by mode (mi)	
Truck	50^
Waste Biomass Collection and Transportation	
Share of waste biomass transported by mode (%)*	
Truck	100.0%

Table 3-10: Key Assumptions for Biomass-based Fuel Production Pathways (*Continued*)

Assumption	***Value***
Average trip distance for waste biomass by mode (mi)	
Truck	50^
Increase in transportation energy to account for collection energy	10.0%
Corn Ethanol Production	
Dry Mill	
Production energy intensity (Btu/gal of EtOH)	36,498
Yield (gal of EtOH/bu of corn)	2.80
Share of Process Fuels	
Natural gas	80%
Coal	20%
Non-combustion emissions (g/gal of EtOH)	
VOC	2.239
PM10	0.856
Co-product allocation shares for Market Value Method[187]	
Corn farming (share of energy allocated to co-products)	24.0%
Ethanol production (share of energy allocated to co-products)	33.0%
Wet Mill	
Production energy intensity (Btu/gal of EtOH)	49,208
Yield (gal of EtOH/bu of corn)	2.70
Share of Process Fuels	
Natural gas	60%
Coal	40%
Non-combustion emissions (g/gal of EtOH)	
VOC	2.239
PM10	0.856
Co-product allocation shares for Market Value Method[188]	
Corn farming (share of energy allocated to co-products)	30.0%
Ethanol production (share of energy allocated to co-products)	31.0%

[187] As per ANL, *GREET 1.6* and ANL, *GREET 1.7 Beta*. See 'EtOH' worksheets. For co-product credits for the Displacement Method, see the 'EtOH' worksheets.
[188] As per ANL, *GREET 1.6* and ANL, *GREET 1.7 Beta*. See 'EtOH' worksheets. For co-product credits for the Displacement Method, see the 'EtOH' worksheets.

Table 3-10: Key Assumptions for Biomass-based Fuel Production Pathways (**Continued**)

Assumption	*Value*
Cellulosic Ethanol Production	
Yield (gal of EtOH/dt of biomass)	
Woody biomass	100
Herbaceous biomass	105
Co-produced electricity (kWh/gal of EtOH)	
Woody biomass	11.53
Herbaceous biomass	5.76
Content of cellulose and hemicellulose in feedstock (% by weight)	
Woody biomass	59.0%
Herbaceous biomass	63.0%
Non-combustion emissions (g/gal of EtOH)	
VOC	1.120
PM10	0.856
Ethanol Transportation and Distribution	
Petroleum-fuel blending agent for ethanol blends	RFG
Share of ethanol transported by mode (%)*	
Barge	40.0%
Rail	40.0%
Truck (to bulk terminal)	20.0%
Truck (to fueling stations)	100.0%
Average trip distance for ethanol by mode (mi)	
Barge	520^
Rail	800
Truck (to mixing station)	80^
Truck (to farm)	30^

* Transport mode shares may add up to more than 100% as fuels may be transported through multiple modes. Additionally, individual mode shares may exceed 100% as some fuels pass through the same type of mode during more than one leg of their journey.
^ Round-trip energy use and emissions for this transport mode are calculated – i.e. back-haul trips are assumed to be empty.

Table 3-11: Well-to-Pump Energy Use and Emissions Results for Biomass-based Fuel Production Pathways

(Btu or g/mmBtu of fuel available at fueling station pumps)	***E100 from Corn (Displacement Method)***	***E100 from Corn (Market Value Method)***	***E85 from Corn (Displacement Method)***	***E85 from Corn (Market Value Method)***	***E100 from Woody Biomass – Hybrid Poplar (Displacement Method)***	***E100 from Woody Biomass – Hybrid Poplar (Energy Content Method)***	***E85 from Woody Biomass – Hybrid Poplar (Displacement Method)***	***E85 from Woody Biomass – Hybrid Poplar (Energy Content Method)***
Total Energy	704,686	599,253	621,879	537,626	127,880	873,970	165,278	755,885
Net Fossil Energy Ratio	1.42	1.68	1.62	1.88	-1.05	16.71	-1.45	9.07
Fossil Fuels	701,834	594,442	618,425	532,607	-952,827	59,832	-691,409	110,215
Petroleum	72,945	95,194	83,966	101,746	23,602	48,855	44,906	64,896
CO2	-22,082	-30,024	-12,495	-18,841	-190,336	-80,366	-145,685	-58,632
CH4	114.405	96.274	115.099	100.610	-141	8.244	-87	31.062
N2O	32.144	33.245	25.764	26.644	10.003	8.366	8.238	6.942
GHGs	-9,715	-17,697	-2,091	-8,469	-190,191	-77,599	-144,956	-55,828
VOC: Total	20.391	34.046	19.763	30.675	17.306	23.600	17.320	22.303
CO: Total	53.669	55.926	46.857	48.661	6.587	15.998	9.587	17.037
NOx: Total	108.465	122.201	96.296	107.272	-28.735	50.401	-12.312	50.332
PM10: Total	116.405	106.728	95.573	87.841	-123.053	16.700	-93.982	16.646
SOx: Total	30.461	26.638	29.196	26.141	-68.315	25.225	-48.996	25.051
VOC: Urban	1.269	1.513	2.185	2.380	1.040	1.212	2.004	2.140
CO: Urban	1.233	1.725	1.853	2.245	-1.067	0.296	0.032	1.110
NOx: Urban	2.570	3.409	3.568	4.239	-4.177	0.845	-1.773	2.202
PM10: Urban	0.038	0.251	0.365	0.535	-0.695	0.077	-0.216	0.395
SOx: Urban	0.192	0.801	1.614	2.100	-5.062	0.245	-2.545	1.656

Table 3-11: Well-to-Pump Energy Use and Emissions Results for Biomass-based Fuel Production Pathways (**Continued*****)***

(Btu or g/mmBtu of fuel available at fueling station pumps)	*E100 from Wood y Biomass – Waste (Displacement Method)*	*E100 from Woody Biomass – Waste (Energy Content Method)*	*E85 from Woody Biomass – Waste (Displacement Method)*	*E85 from Woody Biomass – Waste (Energy Content Method)*	*E100 from Herbaceous Biomass – Switchgrass (Displacement Method)*	*E100 from Herbaceous Biomass – Switchgrass (Energy Content Method)*	*E85 from Herbaceous Biomass – Switchgrass (Displacement Method)*	*E85 from Herbaceous Biomass – Switchgrass (Energy Content Method)*
Total Energy	88,287	847,141	133,927	734,639	402,892	795,822	382,978	694,023
Net Fossil Energy Ratio	-1.01	29.77	-1.38	11.18	-2.65	8.72	-4.24	6.51
Fossil Fuels	-991,561	33,587	-722,080	89,431	-377,002	114,700	-235,585	153,648
Petroleum	-3,807	30,510	23,206	50,371	42,609	53,916	59,952	68,903
CO2	-178,709	-72,651	-136,481	-52,524	-124,124	-84,993	-93,272	-62,295
CH4	-144.929	5.397	-90.191	28.807	-54.993	17.143	-18.997	38.106
N2O	8.588	6.789	7.116	5.692	28.509	27.860	22.887	22.373
GHGs	-179,090	-70,433	-136,169	-50,155	-116,441	-75,996	-86,575	-54,559
VOC: Total	15.338	22.283	15.763	21.260	20.840	23.905	20.118	22.545
CO: Total	-1.114	10.833	3.489	12.947	13.786	17.976	15.285	18.602
NOx: Total	-52.245	34.169	-30.927	37.479	32.409	70.706	36.089	66.406
PM10: Total	-124.956	15.417	-95.489	15.630	-51.504	17.981	-37.344	17.660
SOx: Total	-72.095	22.689	-51.989	23.043	-43.383	7.841	-29.260	11.290
VOC: Urban	0.979	1.171	1.955	2.107	1.177	1.252	2.112	2.172
CO: Urban	-1.190	0.210	-0.066	1.043	0.142	0.714	0.989	1.442
NOx: Urban	-4.384	0.704	-1.937	2.091	-1.221	1.197	0.567	2.481
PM10: Urban	-0.735	0.050	-0.248	0.374	-0.265	0.112	0.125	0.423
SOx: Urban	-5.221	0.138	-2.671	1.571	-2.309	0.322	-0.366	1.717

*Table 3-11: Well-to-Pump Energy Use and Emissions Results for Biomass-based Fuel Production Pathways (***Continued***)*

(Btu or g/mmBtu of fuel available at fueling station pumps)	*E100 from Herbaceous Biomass – Waste (Displacement Method)*	*E100 from Herbaceous Biomass – Waste (Energy Content Method)*	*E85 from Herbaceous Biomass – Waste (Displacement Method)*	*E85 from Herbaceous Biomass – Waste (Energy Content Method)*
Total Energy	301,486	714,806	302,697	629,881
Net Fossil Energy Ratio	-2.10	27.95	-3.19	10.97
Fossil Fuels	-475,783	35,780	-313,789	91,166
Petroleum	15,854	32,487	38,770	51,936
CO2	-125,413	-85,984	-94,291	-63,079
CH4	-69.769	5.343	-30.694	28.764
N2O	6.782	6.069	5.686	5.122
GHGs	-124,776	-83,991	-93,173	-60,887
VOC: Total	18.797	22.270	18.501	21.250
CO: Total	4.376	10.445	7.836	12.640
NOx: Total	-8.353	34.684	3.819	37.886
PM10: Total	-55.113	15.096	-40.201	15.376
SOx: Total	-48.226	3.967	-33.094	8.222
VOC: Urban	1.080	1.175	2.036	2.111
CO: Urban	-0.483	0.216	0.494	1.047
NOx: Urban	-1.826	0.714	0.088	2.099
PM10: Urban	-0.354	0.041	0.054	0.367
SOx: Urban	-2.528	0.147	-0.539	1.578

3.4 Electricity Pathways

This study includes three electricity-based vehicle fuels: gaseous and liquid hydrogen (GH2 and LH2) produced from electricity via electrolysis of water, as well as electricity as a direct fuel for battery electric vehicles and plug-in hybrid vehicles. As electricity can be derived from a number of sources, each with its own energy efficiency and emissions profile, the source of electricity clearly has an impact on the energy and environmental benefits of electricity-based fuels. As such, this study considers electricity from two representative national electricity mixes – a 'business-as-usual' U.S. average mix and a 'high renewables' case mix. Figure 3-21 below summarizes the major stages in the fuel production pathway for gaseous or liquid hydrogen produced via electrolysis of water at vehicle fueling stations. Electricity from the grid – either from the U.S. average or high renewables mixes – is transmitted to vehicle fueling stations where it is used to power electrolysis units sized

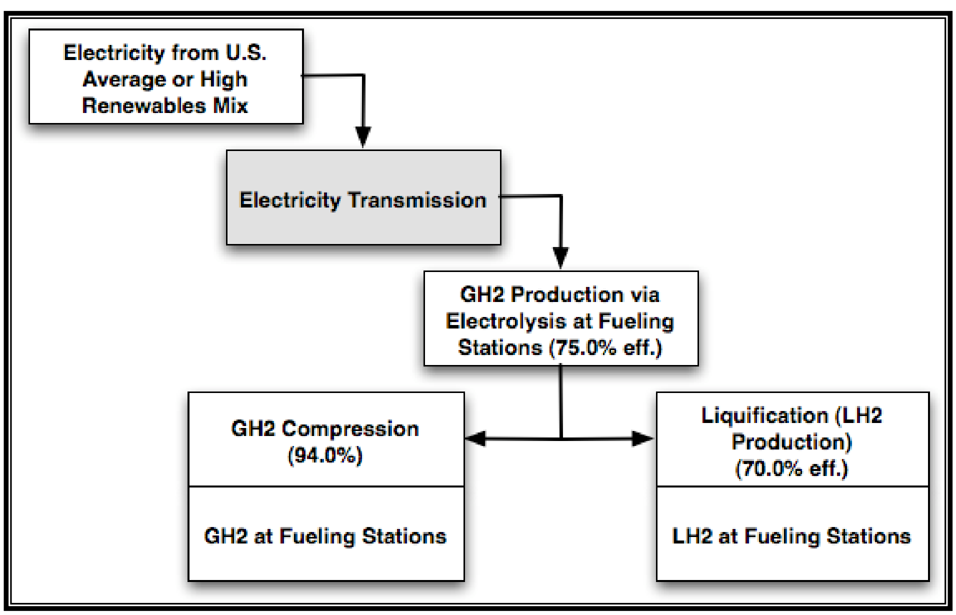

Figure 3-21: Major Stages in Gaseous and Liquid Hydrogen Production from Electrolysis of Water at Fueling Stations Pathways

appropriately to the station's demand. These electrolysis units produce gaseous hydrogen, which is then either compressed or liquefied and stored on site for later fueling of fuel cell vehicles.

This study also includes four pathways representing the use of renewable electricity produced in remote areas (e.g., wind power in the Great Plains or solar farms in the Southwest, etc.) including: GH2 and LH2 from gaseous hydrogen produced via electrolysis at remote renewable locations and pipelined to demand centers (summarized in Figure 3-22); electricity transmitted from remote renewables via high voltage direct current (HVDC) transmission lines (summarized in Figure 3-23); and electricity derived from hydrogen transmitted via pipeline and converted to electricity in high temperature fuel cell power plants (summarized in Figure 3-24).

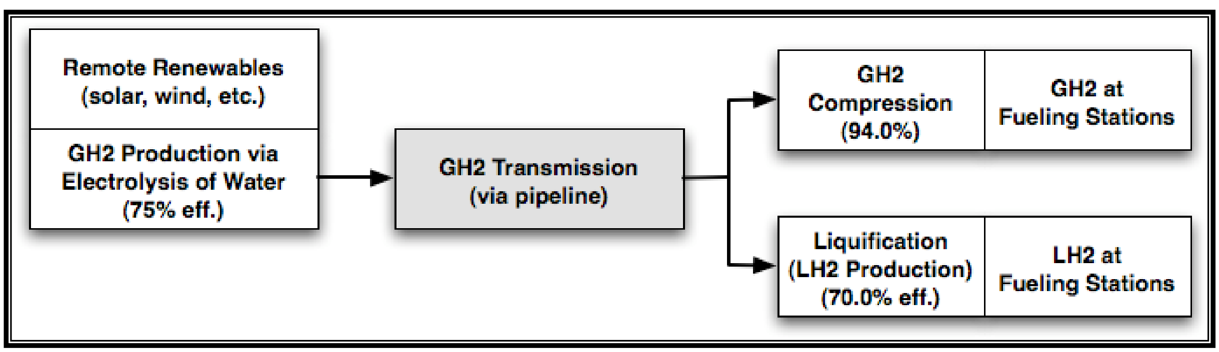

Figure 3-22: Major Stages in Remote Renewables to GH2 and LH2 Pathways

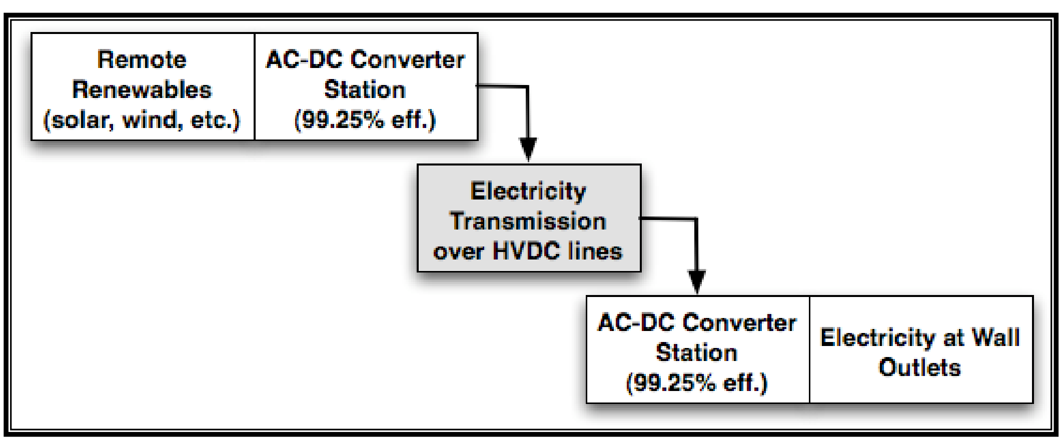

Figure 3-23: Major Stages in Remote Renewables to Electricity via HVDC Pathway

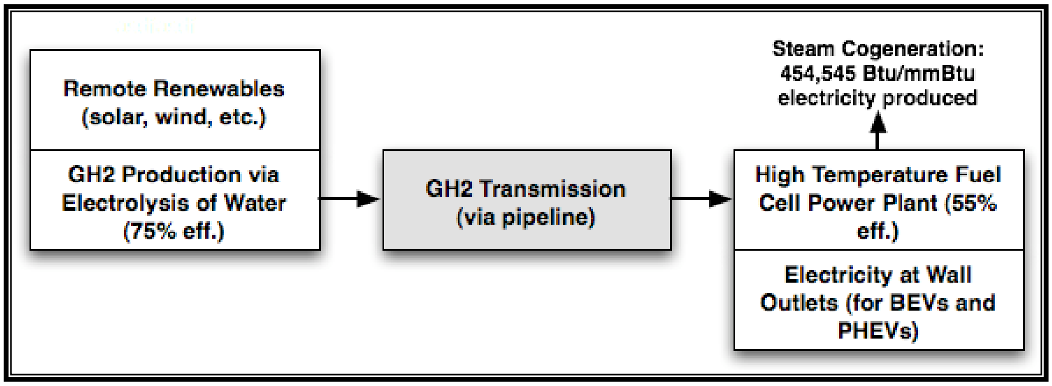

Figure 3-24: Major Stages in Remote Renewables to Electricity via GH2 Pipeline Pathway

In addition to the transportation fuels discussed above, electricity is clearly utilized in a number of other processes modeled throughout this study. In these cases, electricity is assumed to come from the 'business-as-usual' U.S. average mix.

Electricity Sources and Energy Accounting Methods:

Figure 3-25 below illustrates the major stages in the production of electricity. Electricity can be derived from several sources, each of which is modeled by this study. These include coal, natural gas, petroleum, nuclear, biomass, and other renewables (including wind, solar, hydro, geothermal, ocean tidal and wave power). For coal, petroleum, natural gas, and biomass-fired power plants, this study models the energy use and emissions associated with the production/recovery, processing and transportation of the feedstocks used for electricity generation as well as the conversion efficiency and emissions associated with electrical generation using these feedstocks.

This study utilizes an energy accounting system that seeks to address resource depletion and emissions of GHGs and criteria pollutants. As such, for electricity generation from other renewables, this study takes into account only the energy contained in the generated electricity. If the primary energy used for renewable electricity generation

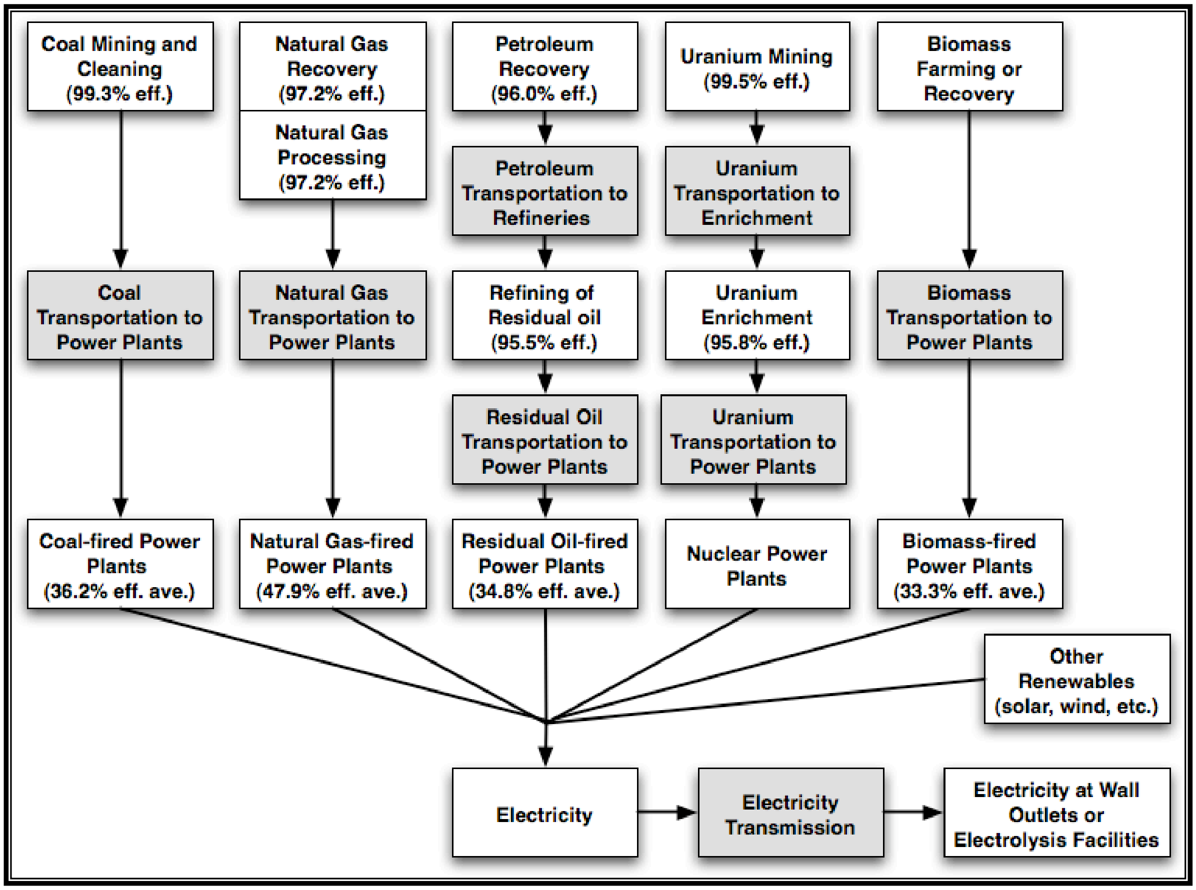

Figure 3-25: Major Stages in Electricity Production Pathway

(i.e., the energy contained in solar radiation or the kinetic energy of wind, etc.) were included, the renewable electricity-based fuel production pathways would result in substantial WtP energy losses. However, as the energy contained in the primary 'fuels' for renewable power sources is 'free' – that it, it is not subject to energy resource depletion, emissions or fuel costs – inclusion of this primary energy in a WtW analysis is not meaningful.[189]

This study applies a similar logic to the energy accounting for nuclear generated electricity. Energy accounting for nuclear energy could be based either on the energy

[189] See GM, ANL, et al. (2005), p. 88 for a discussion of the starting points for energy accounting in WtW analysis. Some researchers may argue that accounting for Btus in primary renewable energy sources could serve as a helpful surrogate for determining other resource needs (such as land and water requirements, etc.). However, this study maintains, as does the GM, ANL et al. (2005) WtW study, that the depletion of other resources should be addressed directly instead of using Btus as a surrogate. See p. 88.

contained in the uranium fuel or in the generated electricity. While uranium is not a renewable resource, United States and worldwide uranium reserves exist in significant enough quantities that resource depletion associated with nuclear power may be of little concern. As the GM, ANL, et al. (2005) WtW study discusses, U.S. uranium reserves are sufficient to last more than 150 years at current levels of uranium consumption.[190] Additionally, if recycling of spent nuclear fuel into additional fissionable material were utilized in the United States, as it is elsewhere in the world, U.S. domestic uranium supplies could be stretched for centuries. Finally, U.S. reserves represent only a few percent of total worldwide resources.[191] Thus, uranium resources do not present a constraint for nuclear generation. Furthermore, like renewables, the production of electricity from nuclear power plants results in no GHG or criteria pollutant emissions. For these reasons, this study begins to account for energy contained in the electricity generated by nuclear power plants, rather than the energy contained in the uranium fuel. However, unlike with renewables, this study does take into account the upstream energy use and emissions associated with the mining, transportation and enrichment of nuclear fuel.[192]

3.4.1 Recovery/Production, Processing and Transportation of Feedstocks for Electricity Generation

This section discusses the recovery or production, processing and transportation of the various feedstocks used to generate electricity: coal, natural gas, petroleum, uranium, and biomass. Of those, the recovery or production and processing of petroleum, natural gas and

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[190] See GM, ANL (2005), p. 88. The authors cite the EIA's *Uranium Industry Report 2002*.
[191] ibid. p. 89.
[192] Unfortunately, GREET 1.6 does not include the energy use and emissions associated with the downstream disposal and storage of nuclear waste, nor does it include the production of nuclear waste amongst the pollutants it considers. GREET 1.7 will model this stage of the fuel cycle and will thus provide a more complete analysis of nuclear-generated electricity.

biomass have been discussed previously in other sections of this study (see Section 3.1 for petroleum, 3.2 for natural gas, and 3.3 for biomass). The recovery and processing of coal and uranium are discussed here. This section also describes the transportation of all five of the above feedstocks to electricity generation facilities. Various renewable energies – i.e. solar, wind, hydro, etc. – are also used as feedstocks for electricity generation. However, there are no feedstock recovery/production, processing or transportation stages associated with the use of renewables. As such, they are not discussed in this section.

Coal Mining, Cleaning and Transportation:

Coal is recovered either in underground mines or in open pit, or surface mines. Coal is classified into four types based on carbon, volatile matter and energy content: lignite, sub-bituminous, bituminous and anthracite. Lignite coal is of the lowest quality and is a brownish-black coal with a high moisture and volatile matter content. It typically has an energy content between 6,300-8,300 Btu/lb. Sub-bituminous coal is dull black in color with moisture and volatile matter contents between lignite and bituminous coal. Its energy content is between 8,300-11,500 Btu/lb. Bituminous coal is the most common type in North America and is a dense and black coal with moisture content less than 20%. It typically has a carbon content ranging from 69% to 86% by dry weight and its energy content ranges from 10,500 to 14,000 Btu/lb. Finally, anthracite coal is of the highest quality and is a hard, black lustrous coal containing a high carbon content (between 86-98% by weight) and low volatile matter content.[193] This study assumes that the average quality of coal used for electricity

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[193] See Wang (1999), Volume 1, p. 85.

generation is 20,608,570 Btu/ton (HHV),[194] with a sulfur content of 1.11% and a carbon content of 63.7% by weight.[195]

This study also assumes that 67.0% of the coal used for electricity generation is recovered at surface mines, while the remaining 33% is recovered at underground mines.[196] Coal mining is assumed to be a 99.3% efficiency process, on average.[197] Coal mining produces significant non-combustion emissions of both particulate matter (PM10) and methane (CH_4). Methane is naturally contained in coal beds and much of it is released during coal mining. While coal-bed methane may itself be mined as a non-conventional source of natural gas, the methane released during coal mining operations is uneconomical to recover and is simply released into the atmosphere. Based on the values reported in Wang (1999), this study assumes that underground coal mining operations release 80.29 grams of CH_4 per mmBtu of coal mined, while surface mines release 177.82 g/mmBtu.[198] Coal mining, especially at surface operations also releases large amounts of particulates into the air. Based on the values published in GREET 1.7b, this study assumes that surface mining operations result in 236.0 grams of PM10 emissions per mmBtu of coal mined, while underground operations result in a somewhat more moderate 31.2 g/mmBtu.[199]

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[194] LHV: 19,546,300. As a portion of the energy content contained in water vapor produced by the combustion of coal is utilized in electricity generation, HHVs are appropriate in this case.
[195] These assumptions as per ANL, *GREET 1.7b* (see 'Fuel_Specs' worksheet). ANL, *GREET 1.6* and Wang (1999) reports slightly lower energy and carbon contents of 20,550,000 Btu/ton and 63.7%, reportedly representative of the average quality of coal delivered to electric utilities in 1997. The values reported in GREET 1.7b are pbesumably based on an updated survey of average coal quality and this study uses the more recent figures from GREET 1.7b. Sulfur contents reported by the two versions are the same.
[196] This split as per ANL, *GREET 1.7b* which reportedly bases these values on the EIA's 2002 Annual Energy Review (Table 7.2). See 'Coal' worksheet.
[197] As per ANL, *GREET 1.6* and ANL, *GREET 1.7b*. See 'Coal' worksheet in both.
[198] Wang (1999), Volume 1, p. 86. These values reportedly based on a 1999 life-cycle study of coal-fired power plants conducted by Spath and Mann.
[199] ANL, *GREET 1.7 Beta*. See 'Coal' worksheet.

After mining, coal is usually cleaned at mining sites in order to remove impurities including ash, sulfur, and rock. This process results in non-combustion emissions of volatile material, particulates and sulfur (the latter leaches out of the coal when exposed to rainfall). As per the values published in GREET 1.6, this study assumes that coal-cleaning results in the emission of 6.87 grams of VOC, 3.30 grams of PM10 and 5.53 grams of SO_x per mmBtu of coal cleaned.[200] The energy use during the coal-cleaning stage is included in the energy efficiency for the mining stage above.

After mining and cleaning, coal is transported by barge and rail to coal-fired power plants. The transportation of coal for use in coal-fired power plants is summarized in Figure 3-26 below. The United States has significant reserves of coal and is not expected to import significant quantities of coal in the near future.[201] Thus, this study assumes that all coal consumed by coal-fired power plants is mined in North American (predominately within the United States).

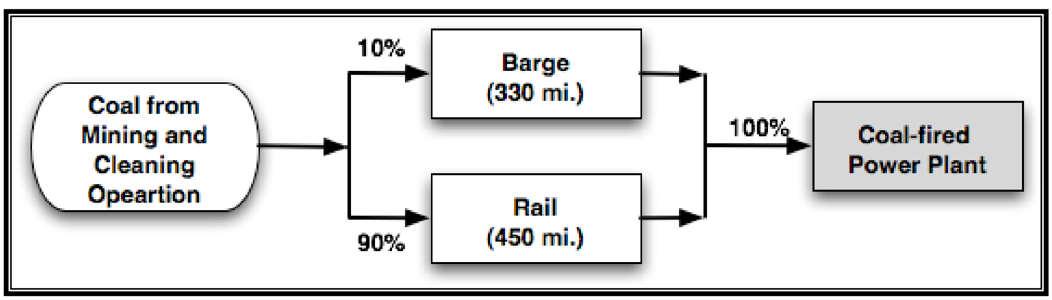

Figure 3-26: Transportation of Coal for Electric Power Generation[202]

Uranium Mining, Enrichment and Transportation:

Uranium for eventual use in nuclear power plants is mined as uranium ore using traditional hard rock mining methods (e.g., open pit or underground mining, etc.). This

[200] ANL, *GREET 1.6*. See 'Coal' worksheet.
[201] EIA *AEO2006* predicts that in 2025, less than 4% of total U.S. coal consumption will be met by imported coal, most likely from Canada. See p. 157, Table A15.
[202] Transportation distances and mode shares as per ANL, *GREET 1.6*. See 'T&D' worksheet.

uranium ore is then milled, chemically processed and dried into a uranium concentrate known as 'yellowcake.'[203] Based on the values published in GREET 1.6 and Wang (1999), this study assumes that uranium mining and processing into yellowcake is a 99.5% efficient process.[204] Uranium mining results in no appreciable quantities of non-combustion emissions of any of the criteria pollutants or GHGs considered in this study.

Yellowcake is then transported via rail and truck to uranium enrichment facilities. Naturally occurring uranium consists mostly of the isotope, uranium-238 and only contains small amounts of the fissionable isotope uranium-235 (typically around 0.71% by weight).[205] Before being used as a fissionable fuel in a nuclear power plant, the uranium-235 content of the fuel must be increased through the process of uranium enrichment. Uranium is typically enriched through one of two processes, both of which exploit the slightly different weights of the two uranium isotopes: gaseous diffusion or gas centrifuges. In gaseous diffusion plants, the uranium in yellowcake is turned into gaseous uranium hexafluoride and forced through a semi-permeable membrane, which slightly separates the uranium-235 and 238 isotopes. Gas centrifuge plants use large numbers of rotating cylinders filled with uranium hexafluoride. The rotation creates a strong centrifugal force which pulls the slightly heavier uranium-238 isotopes towards the outside of the cylinders while the lighter uranium-235 moves towards the center. Both types of plants employ a number of identical, repeated stages to produce successively higher concentrations of uranium-235.[206] Gaseous diffusion is significantly

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[203] ANL, *GREET 1.7b* assumes a uranium oxide concentration of 94% in yellowcake. See 'Uranium' worksheet.

[204] Wang (1999), Volume 1, p. 86 and ANL, *GREET 1.6* (see 'Uranium' worksheet). Wang (1999) reports that this figure is based on a 1991 ANL study by M.A. Delucci.

[205] GREET 1.6 is not explicit about the assumed uranium-235 content of the naturally occurring uranium used as a feedstock for enrichment. GREET 1.7b, however, assumes a uranim-235 content of 0.71% by weight. See 'Uranium' worksheet.

[206] See "Enriched Uranium". *Wikipedia*. May 10, 2006. <http://en.wikipedia.org/wiki/Uranium_enrichment>. Accessed 5-13-2006.

more energy intensive than gas centrifuge enrichment and centrifuge plants have largely replaced gaseous diffusion plants in the United States.[207] The light-water nuclear reactors used in the U.S. require uranium fuel with uranium-235 concentrations between 3 and 5%, referred to as low-enriched uranium.[208] As per the values assumed by GREET 1.6 and Wang (1999), this study assumes that uranium enrichment is a 95.8% process.[209]

Finally, after enrichment, uranium fuel suitable for use in nuclear reactors is transported via truck to nuclear power plants. Figure 3-27 below summarizes the transportation of uranium used as a feedstock for nuclear power generation. As discussed above, the United States has large reserves of uranium relative to its level of consumption and this study assumes that all uranium used for nuclear power generation is mined and enriched in North America.

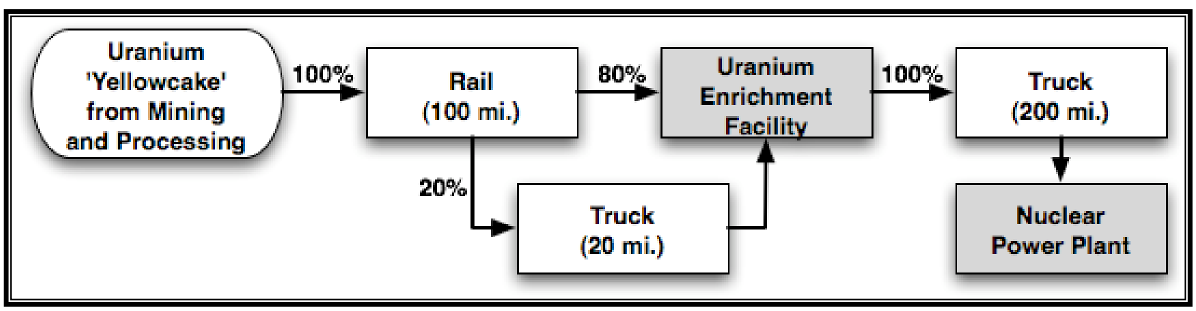

Figure 3-27: Transportation of Uranium for Electric Power Generation

Residual Oil, Natural Gas and Biomass Transportation for Electric Power Generation:

The transportation of petroleum (residual oil), natural gas, and biomass for use in electric power generation is described in this section. The production or recovery, and

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[207] ANL, *GREET 1.7 Beta* assumes that by 2020, only 10% of uranium enrichment will occur in gaseous diffusion plants. See ‘Fuel_Prod_TS’ worksheet.
[208] Again, GREET 1.6 is not explicit about the assumed uranium-238 content of the fuel for nuclear power but GREET 1.7b assumes a uranium-238 content of 3.5% for use in light-water reactors. See ‘Uranium’ worksheet.
[209] Wang (1999), Volume 1, p. 86 and ANL, *GREET 1.6* (see ‘Uranium’ worksheet). Wang (1999) again bases this figure on a the Delucci (1991) ANL study.

processing of these feedstocks are discussed previously in this study. After recovery and transportation to refineries (see Section 3.1.1 above) crude oil is refined into residual oil for use in oil-fired power plants at petroleum refineries. This is assumed to be a 95.5% efficient process, as per the assumptions in GREET 1.6.[210] The residual oil is then transported from refineries, which could be located either in North America or overseas, to oil-fired power plants via a combination of ocean tanker (for residual oil imported from overseas), barge, pipeline and rail. Figure 3-28 below summarizes the transportation of residual oil for use at oil-fired power plants.

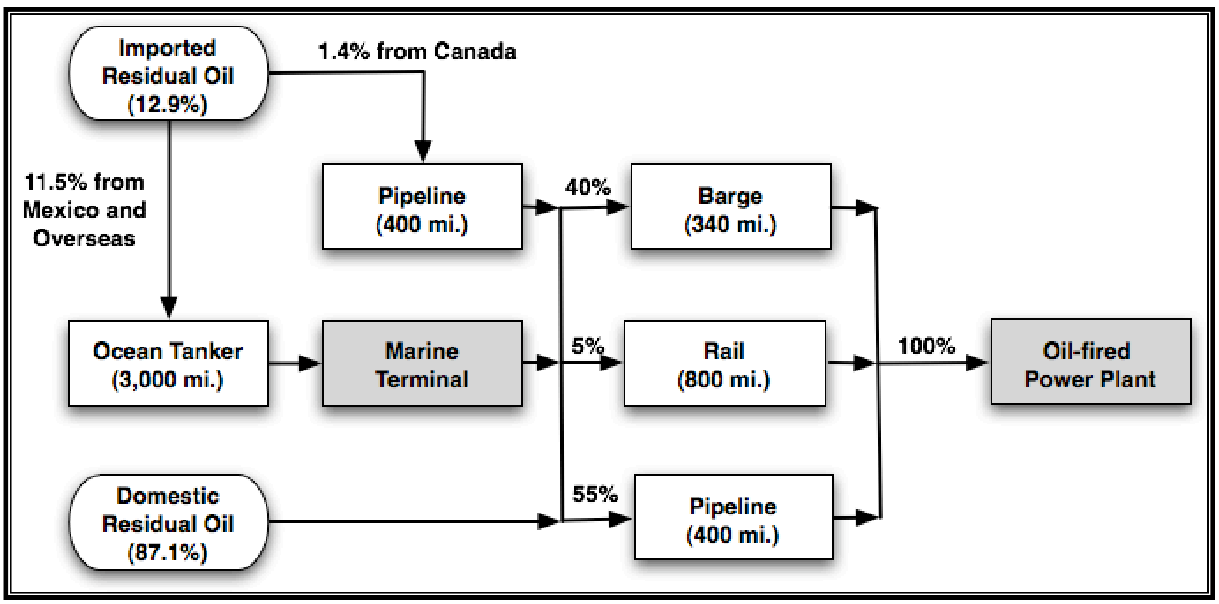

Figure 3-28: Transportation of Residual Oil for Electric Power Generation[211]

After recovery and processing (see Section 3.2.1 above), natural gas is transported to natural gas-fired power plants in one of two pathways. For non-North American natural gas,

[210] ANL, *GREET 1.6*. See 'Inputs' worksheet.
[211] Shares of imported and domestic refined products from EIA, *AEO2006*, p. 153, Table A11. Shares of imported residual oil from Canada and elsewhere are an average of shares for 2000 to 2005 (see EIA, "U.S. Imports by Country of Origin"). Assumes Canadian fuels are imported via pipeline while Mexican and fuels from overseas are transported via ocean tanker. An extensive pipeline system connects Canada and the U.S. while few span the U.S. Mexico boarder (see DOE, "An Energy Overview of Mexico"). Average 1-way trip distances as per GREET 1.6. Transportation mode shares updated from GREET 1.6 to reflect share and origin of imported residual oil.

the pipeline-quality natural gas produced at the natural gas processing facility is liquefied at an adjacent facility and readied for overseas shipment via specialized LNG ocean tankers. These LNG tankers then transport the LNG to terminals in North America where the LNG is re-gasified and pipelined to natural gas-fired power plants. Natural gas of North American origin is simply pipelined from the processing plant to natural gas-fired power plants. As discussed in Section 3.2 above, this study assumes that 12.92% of natural gas consumed in the United States by 2025 is imported from overseas as LNG. Figure 3-29 below summarizes the transportation of natural gas for use in natural gas-fired power plants.

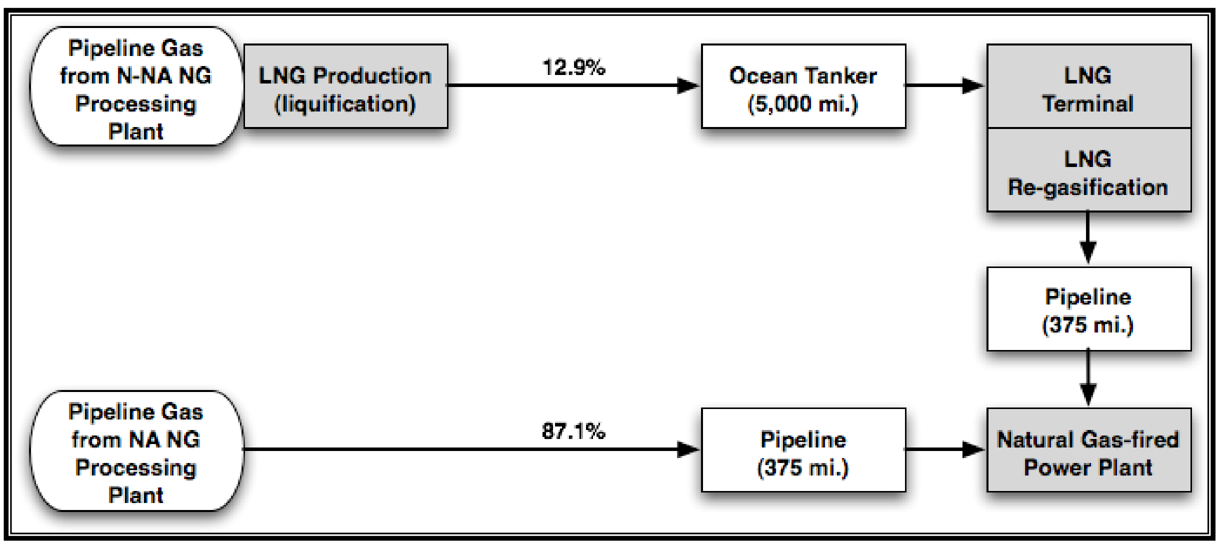

Figure 3-29: Transportation of Natural Gas for Electric Power Generation[212]

The production (farming) or recovery (collection of waste) of woody and herbaceous biomass is discussed in detail in Sections 3.3.2 and 3.3.2 above. Once the biomass is harvested and collected, it is transported to biomass-fired power plants via truck. As discussed in Section 3.3.2, the transportation of biomass over long distances can become prohibitively expensive. Typically, at distances greater than around 50 miles, delivery costs

[212] Transportation distances as per ANL, *GREET 1.6*. See 'T&D' worksheet. Share of North American and non-North American natural gas from EIA, *AEO2006*, p. 155, Table A13.

for biomass begin to dominate the cost of the biomass itself.[213] For this reason, biomass-fired power plants must be located relatively close to the source of biomass feedstock. This study thus assumes that biomass is transported only 50 miles on average to reach the power plant. Figure 3-30 summarizes the simple transportation flow for biomass used as a feedstock for biomass-fired power plants.

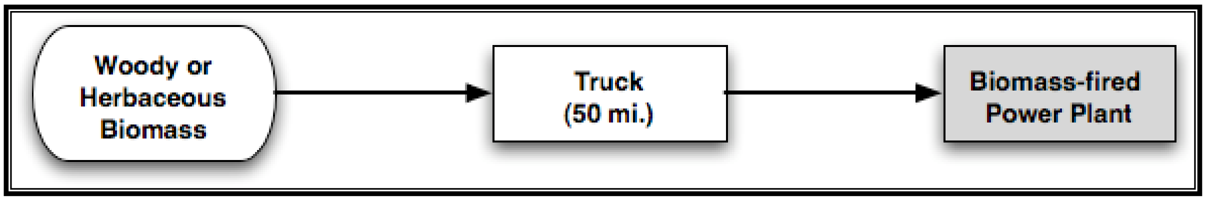

Figure 3-30: Transportation of Biomass for Electric Power Generation

Note that GREET 1.6 does not include a specific biomass-to-electricity pathway. GREET 1.7b will include this pathway, but the earlier version of the model does not distinguish biomass from other renewables. GREET does not assign any energy use or emissions associated with the generation of electricity from renewables, or for the production or transportation of their respective feedstocks (e.g., moving wind for wind power, solar radiation for solar, moving water for hydropower, etc.). Since the production, transportation and combustion of biomass clearly consumes energy and results in emissions of GHGs and criteria pollutants, it is inappropriate to include biomass amongst the other renewables. Thus, this study modifies GREET 1.6 to include a biomass-to-electricity pathway and specifies the share of power from biomass-fired plants in the electricity mix. The feedstock for biomass-fired power plants is assumed to come from an even (50%-50%) mix of dedicated woody and

[213] At 20-30 cents per dry ton per mile, perhaps a representative transportation cost value for a mix of herbaceous and woody biomass, transporting the feedstock 50 miles costs $10-15 per ton, roughly equal to the $10-15 per dry ton cost that Walsh, et al. (1999) estimates for agricultural residues.

herbaceous biomass crops (e.g., hybrid poplars and switchgrass). The production of these crops is discussed in detail in Section 3.3.2 above.

3.4.2 Electricity Generation and Transmission

This study models the generation of electricity from petroleum (residual oil), natural gas, coal and biomass-fired power plants, all of which produce emissions. Additionally, this study includes the generation of electricity from nuclear power plants, which do not result in any combustion emissions but result in upstream emissions related to the mining, enriching and transportation of the uranium fuel used in these power plants (as discussed in Section 3.4.1 above). Finally, this study models the generation of power from renewable resources including wind, solar, geothermal, hydro, wave and tidal power. These renewables produce no emissions, nor are there any emissions associated with any upstream stages. The combustion technologies used to produce electricity from petroleum, natural gas, coal and biomass are discussed below.

Petroleum-fired Power Plants

Petroleum-fired power plants produce electricity by combusting residual oil to power a steam or Rankine cycle. That is, the combusting fuel produces heat, which creates steam. The steam spins a steam turbine that in turn spins a generator, producing electricity. This process is known as a steam or Rankine cycle and is common to coal, nuclear and some natural gas plants (i.e. natural gas utility boilers and the steam cycle portion of natural gas combined cycle plants). This study assumes that the average efficiency of petroleum-fired power plants in 2025 is 34.8%, as per the assumptions in GREET 1.7b.[214] The emissions associated with petroleum-fired power plants are summarized in Table 3-12 below.

Natural Gas-fired Power Plants

Natural gas-fired power plants come in three main varieties: utility boiler or steam turbine plants, simple cycle or combustion turbine plants, and combined cycle plants. Utility boiler or steam turbine plants combust natural gas creating heat to power a Rankine cycle, as described above. This study assumes an average efficiency of 34.8% for natural gas-fired utility boiler power plants.[215] Natural gas-fired combustion turbine power plants produce electricity by combusting natural gas in the presence of compressed air. The resulting hot, expanding gas is directed through a nozzle over the blades of a gas turbine which spins a generator, creating electricity. This process is known as the Brayton cycle. These combustion turbine power plants are also referred to as simple cycle plants, in contrast with combined cycle plants. Combined cycle power plants combine both a gas combustion turbine (Brayton cycle) and a steam turbine (Rankine cycle) powered by steam created by the waste heat from the combustion turbine cycle. Utilizing the waste heat from the Rankine cycle boosts the overall efficiency of combined cycle power plants considerable. This study assumes that by 2025, simple cycle natural gas plants will operate at an average efficiency of 33.5%, while combined cycle plants will operate at 60% efficiency. These assumptions are based on those published in GREET 1.7b.[216] Additionally, based on EIA forecasts, this study assumes that 53.15% of natural gas-fired power plants will be combined cycle plants by 2025, while 38.6% will be simply cycle plants and the remaining 8.25% will be steam turbine

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[214] ANL, *GREET 1.7 Beta*. See 'Fuel_Prod_TS' worksheet. Reported value is for the year 2020.
[215] ibid. See 'Fuel_Prod_TS' worksheet. Reported values are for 2020.
[216] ibid. See 'Fuel_Prod_TS' worksheet. Reported values are for 2020.

plants.[217] The emissions associated with natural gas-fired power plants are summarized in Table 3-12 below.

Coal-fired Power Plants

The vast majority of coal-fired power plants are pulverized coal plants. Pulverized coal (PC) plants crush and then pulverize coal into a fine powder which is blown into a combustion chamber and ignited to produce heat. The heat creates steam and powers a Rankine cycle. PC plants are a very mature technology, accounting for well over 90% of coal-fired power plants worldwide[218] and providing the largest share of the United States' electricity generation mix.[219] The International Energy Agency reports that the efficiency of PC plants can be as low as 30%, while typical plants operate in the 34-35% range.[220] The IEA also reports that newer PC plants utilizing supercritical steam can reach efficiencies as high as 47-50%.[221] This study assumes that the average efficiency of a pulverized coal plant in 2025 is 35.5%, a value midway between the typical operating efficiencies reported by the IEA.

By 2025, several advanced coal-fired power plant technologies will likely achieve moderate market penetration.[222] The most notable of these technologies is the integrated

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[217] EIA *AEO2006*, p. 190, Table D6. Values are reported for 2020 and 2030. Assumed values for 2025 are the average of two reported values. Table D6 reports natural gas and oil-fired steam turbine capacity together. In order to solve for the share of natural gas-fired plants amongst oil and gas-fired steam turbine plants, this study fist assumes that the share of natural gas-fired capacity amongst natural gas and oil-fired capacity reported in Table D6 is the same as the share of natural gas-fired generation amongst natural gas and oil-fired generation reported on p. 157, Table A8. The portion of natural gas-fired capacity amongst oil and gas-fired steam turbine capacity reported in Table D6 is thus the remaining capacity necessary to make these shares equal.
[218] International Energy Agency (IEA). "Pulverised coal combustion (PCC)". *IEA Clean Coal Centre*. <http://www.iea-coal.org.uk/content/default.asp?PageID=65>. Accessed 5/13/2006.
[219] See EIA *AEO2006*, p. 147, Table A8 and p. 190, Table D6.
[220] IEA "Pulverised coal combustion (PCC)".
[221] ibid.
[222] See Aiken, Richard, et al. *Coal-Based Integrated Gasification Combined Cycle: Market Penetration Strategies and Recommendations*. (Booz Allen Hamilton, Sept. 2004).

gasification combined cycle (IGCC) coal-fired power plant. IGCC power plants generate electricity in a combined cycle configuration with the gas turbine powered by combustion of a synthetic gas produced by gasifying coal. Gasification of coal occurs during the partial combustion of the coal (or other carbon-rich feedstock) within a pressurized chamber in the presence of a controlled shortage of oxygen or air. The resulting hydrogen and carbon-rich synthetic gas, or syngas, can be combusted to power a combined cycle power plant as in a natural gas-fired combined cycle plant.[223] Prior to combustion, the syngas can be cleaned to remove significant quantities of several harmful emissions including particulates, sulfur and mercury.[224] This pre-combustion cleanup of the syngas is the main advantage of IGCC plants over traditional PC plants as the post-combustion scrubbing of flue gas employed at PC plants is generally more difficult and costly because pollutants are not in a concentrated pressurized stream like the syngas.[225] Gasification also makes possible the separation of 90% or more of the carbon from the syngas for later sequestration (as CO_2), thus significantly reducing the GHG emissions from the power plant. However, carbon separation and storage is costly and is not likely to be employed in the absence of strong economic incentives (i.e., a cap or tax on carbon emissions). This study thus assumes that IGCC plants do not employ carbon separation. 300 MW of IGCC demonstration plants are already in operation and several demonstration plants are planned by the end of the decade.[226] Based on the EIA's forecasts, this study assumes that IGCC power plants achieve an 11.88% share of coal-fired power plants by 2025, with traditional PC plants making up the remaining 88.12% of coal-

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[223] See IEA, "Integrated gasification combined cycle (IGCC)". *IEA Clean Coal Centre*. <http://www.iea-coal.org.uk/content/default.asp?PageId=74>. Accessed 5/13/2006.
[224] See Aiken, et al. (2004), p. 2.
[225] ibid. p. 2.
[226] See EIA *AEO2006*, pps, 46, 101, and 190, Table D6.

fired plants.[227] Emissions associated with the production of electricity at coal-fired power plants are summarized in Table 3-12 below.

Biomass-fired Power Plants:

As with coal-fired power plants, biomass-fired plants come in two varieties: utility boiler or steam turbine plants and integrated gasification combined cycle plants. Biomass-fired steam turbine plants combust dried biomass including dedicated energy crops (e.g., switchgrass or hybrid poplars), waste biomass from agricultural, forestry or industrial processes, municipal solid waste, etc. The combusted biomass creates steam to power a Rankine cycle and generate electricity. Before combustion, the biomass feedstock is generally homogenized and processed (including chopping, grinding, baling, cubing and pelletizing).[228] The United States is currently home to nearly 1,000 biomass-fired power plants, most of which are small, with an average capacity of only 20 MW.[229] The small size is due to the difficulty of transporting biomass feedstocks over long distances as discussed in Section 3.4.1 above. Thus, biomass-fired power plants are typically located close to available sources of feedstock and are small in size. Additionally, due to their small size, biomass-fired steam turbine power plants generally have lower electricity conversion efficiencies than larger coal-fired power plants, even though the underlying technology is the same. Current biomass-fired power plants operate at only 20% efficiency on average,

[227] ibid. p. 190, Table D6. Reported values are for 2020 and 2030. Assumed value for 2025 is average of the two and represents 47.7 GW of IGCC capacity. This is consistent with the predictions of Aiken, et al. (2004) who predict that 34 to 98 GW of IGCC capacity could be added by 2025 depending on various market and regulatory factors. See pps. ES-3 to ES-6.
[228] See Aabakken, J. *Power Technologies Data Book: Third Edition.* (Golden, CO: National Renewable Energy Laboratory, April 2005). p. 3.
[229] ibid. p. 4.

according to the National Renewable Energy Laboratory (NREL).[230] However, NREL also predicts that the average efficiency of biomass-fired plants will increase in the future to 33.9% on average.[231] This study thus assumes that biomass-fired steam turbine power plants operate at 33.9% efficiency.

Currently, there are no biomass-fired IGCC plants in operation in the United States. However, the technology, initially developed for use with coal (see above), could be applied to biomass-fired plants as well. As with coal-fired IGCC plants, biomass-fired IGCC plants offer lower emissions than steam turbine biomass plants as they allow the easy cleaning of the syngas before combustion and operate at a higher efficiency (~41.5% by 2025).[232] They also open up the possibility of carbon separation and storage, but as with IGCC coal plants, this process is costly and is not likely to be adopted without strong economic incentives. Thus, this study assumes that biomass IGCC plants do not perform carbon separation and storage. Based on the assumptions in GREET 1.7b, this study assumes that IGCC plants makeup 3% of total biomass-fired capacity in 2025.[233] Emissions profiles for biomass-fired power plants are given in Table 3-12 below. Note that the CO_2 released during combustion of biomass was originally absorbed from the atmosphere during plant photosynthesis. Thus, combustion-related CO_2 emissions are treated as zero for the combustion of biomass in biomass-fired power plants.

Note: As mentioned previously, GREET 1.6 does not include a biomass-to-electricity pathway and instead groups biomass with other renewables. Biomass-fired electricity generation results in combustion emissions, however, and is thus inappropriate to include

[230] ibid. p. 4.
[231] ibid. p. 9.
[232] Efficiency from ibid. p. 9.
[233] ANL, *GREET 1.7 Beta*. See 'Fuel_Prod_TS' worksheet.

amongst other zero-emissions renewable energy technologies. GREET 1.6 does include an emissions profile for biomass-fired utility boilers for use in various processes included in the model (i.e., ethanol production, etc.). Additionally, GREET 1.7b will include a biomass-to-electricity pathway, including biomass-fired IGCC power plants. This study thus draws on GREET 1.7b and the biomass-fired boiler profile included in GREET 1.6, as well as data figures in NREL's *Power Technologies Energy Data Book* to develop the electricity generation portion of the biomass-to-electricity pathway.[234]

Power Plant Combustion Emissions:

The following table summarizes the emissions associated with the combustion technologies and fuels used for electricity generation. It also summarizes the electricity conversion efficiencies assumed by this study.

These emissions profiles are largely based on figures published in GREET 1.6,[235] with the following exceptions: emissions for biomass-fired IGCC plants are constructed as described above; and NO_x and SO_x emissions from petroleum and coal-fired steam turbine power plants as well as NO_x emissions from biomass-fired steam turbine plants are assumed to be 67.16% lower for NO_x and 77.71% lower for SO_x than the 1990 emissions profiles

[234] Emissions profiles for biomass-fired utility boilers drawn from ANL, *GREET 1.6*. See 'EF' worksheet. Emissions profiles for biomass-fired IGCC plants drawn from ANL, *GREET 1.7 Beta*. See 'Electric' worksheet. Reported values for SO_x seem far to high (they are nearly 8 times higher than those reported for biomass-fired utility boilers when IGCC plants should have much lower SO_x emissions). Thus, this study assumes that the proportion of SO_x emissions from biomass-fired utility boiler and IGCC plants are the same as the proportion for coal-fired utility boiler and IGCC plants (i.e., IGCC plants emit 77.64% less SO_x emissions than utility boiler plants). CH4 and N_2O emissions for biomass-fired IGCC plants are not reported in GREET 1.7b and are assumed to be the same as for biomass-fired utility boilers. CO_2 emissions are calculated based on the carbon content of the fuels and the remainder left after VOC, CO and CH4 emissions. Efficiencies for biomass-fired utility boiler and IGCC plants drawn from Aabakken (2005), p. 9.

[235] See ANL, *GREET 1.6*, 'EF' worksheet.

Table 3-12: Power Plant Combustion Emissions and Electricity Conversion Efficiencies

Fuel:	**Petroleum**		**Natural Gas**		**Coal**		**Biomass**	
Combustion Technology:	**Steam Turbine**	**Steam Turbine**	**Simple Cycle**	**Comb. Cycle**	**Steam Turbine**	**IGCC**	**Steam Turbine**	**IGCC**
Combustion Emissions (grams per mmBtu of fuel combusted)								
VOC	2.460	2.700	1.050	1.050	1.140	1.477	5.341	1.228
CO	16.200	41.100	7.500	7.500	9.610	12.309	76.800	10.217
NO_x	23.118	15.600	15.600	15.600	63.539	44.068	36.119	9.511
PM10	6.150	3.700	3.290	3.290	12.617	6.524	12.617	5.413
SO_x	42.569	0.309	0.309	0.309	197.090	44.068	4.100	31.953
CH_4	0.910	1.100	4.260	4.260	0.750	5.098	3.834	3.834
N_2O	0.360	1.100	1.500	1.500	1.060	5.098	11.000	11.000
CO_2	82,677	59,863	59,912	59,912	114,321	114,304	102,241*	102,359*
Conversion Efficiency	34.8%	34.8%	33.5%	60%	35.5%	41.5%	33.9%	41.5%

* Value is for woody biomass-fired plant. Herbaceous biomass has a lower carbon content and results in 95,699 and 95,816 grams of CO_2 emissions per mmBtu of fuel combusted in steam turbine and IGCC plants, respectively.

published in Wang (1999).[236] This decrease in NO_x and SO_x emissions is intended to represent the emissions reductions due to the recently implemented Clean Air Interstate Rule (CAIR).[237] CAIR, announced by the U.S. Environmental Protection Agency (EPA) in March, 2005, implements a cap-and-trade system to achieve significant reductions in NO_x and SO_x (primarily SO_2) emissions from power plants. CAIR applies to 28 eastern states as well as the District of Columbia and is implemented as a series of successively stricter emissions caps phased in incrementally until full implementation in 2015.[238] The EPA estimates that CAIR will reduce national emissions of NO_x from power plants from 6.7 million tons in 1990 to 2.2 million tons by 2015, a reduction of 67.16%. CAIR will reduce

[236] See Wang (1999), Volume 2, p. 4.
[237] See United States Environmental Protection Agency. *Fact Sheet: Clean Air Interstate Rule (CAIR) – Clean Air, Healthier Lives, and a Strong America*. (Washington D.C.: US Environmental Protection Agency, March 2005).
[238] ibid. p. 2.

SO_x emissions 77.71% from 15.7 million tons in 1990 to 3.5 million tons in 2015.[239] This study thus reduces the NO_x and SO_x emissions profiles for those power plants that contribute significantly to emissions of those pollutants – i.e. petroleum and coal-fired steam turbine power plants and biomass-fired steam turbine plants (for NO_x). Natural gas-fired plants do not contributed appreciable amounts of SO_x emissions and this study assumes that they are not affected by CAIR.

The affects of future emissions control legislation are a source of uncertainty for this and other studies attempting to forecast emissions profiles for electric power plants. It is possible that by 2025, CAIR will be extended to include western states, or that an additional stricter cap will be implemented between 2015 and 2025. However, as there is no way to accurately predict what the effects of such future emissions regulations may be, this study only attempts to model the effects of the Clean Air Interstate Rule.

Electricity Transmission Losses:

Electricity is typically produced at power plants at a low voltage of around 25 kilovolts (kV) which is not suitable for long-distance transmission. Thus, after generation, a transformer station at the power plant steps up the electricity to a higher voltage, usually 110 kV and above, for long-distance transmission through the AC electrical grid. At grid exit points, or substations, the electricity is stepped down to lower voltages (33-110 kV) for distribution to consumers. At the final point of use, electricity is stepped down one last time to low voltages suitable for use in electrical lighting, appliances, etc. Energy losses occur

[239] ibid. p. 2.

throughout this pathway, principally due to resistive losses during transmission[240] as well as losses at transformers.

The EIA reports that electricity transmission losses amounted to 226 billion kWh in 2004, or nearly 6% of total U.S. electricity generation. However, according to John Stringer, technical director of the Electric Power Research Institute, transmission losses are routinely underreported.[241] Stringer reports transmission losses of 5% in 1970, 7.2% in 1995 and 9.5% in 2001 and points out that losses are related to how heavily the transmission system is loaded.[242] Very little in the way of major additions to the transmission grid have been made in recent decades despite continued additions to generating capacity. The result has been increased grid congestion and the increasing transmission losses described by Stringer. Unless major additions to the electrical grid are made in the coming decades, additions sufficient to not only keep pace with generation capacity additions but also to ease the level of congestion currently experienced, it is not likely that transmission losses will decrease. This study thus assumes that transmission losses are 10% by 2025.[243]

Electricity Generation Mixes:

As mentioned previously, this study includes two different electricity generation mixes summarized in Table 3-13 below: a U.S. average mix, representing the Energy

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[240] Transmission losses are proportional to the resistance of the line as well as the square of the current transmitted on the line (i.e. Losses ~ RI^2 where I = current and R = resistance). Since current varies inversely with voltage, transmission losses are reduced by transmitting electricity at high voltages. Transmission losses are radiated as heat.

[241] See Stringer, John. "The Challenge for the Grid of the 21st Century" (presentation). Delivered at "Nanotechnology and Energy: Storage and the Grid" Conference, Rice University Nov. 2005.

[242] ibid. p. 10.

[243] Mazz and Hammerschlag (2004) cite 10% transmission losses as "a commonly accepted baseline in the utility industry." See p. 19.

Information Administration's 'business-as-usual' reference case forecast for 2025;[244] and a 'high renewables' mix, representing a national mix with 20% of the electricity generated from biomass and other renewables (i.e., a mix consistent with the implementation of a 20% national Renewable Portfolio Standard). The makeup of the electricity generation mix can have a significant impact on the WtW energy use and emissions associated with electric vehicles (EVs) and fuel cell vehicles (FCVs) fueled with hydrogen from electrolysis. As electricity mixes vary greatly from region to region, the energy and environmental benefits of EVs and FCVs utilized in different regions varies accordingly.

Furthermore, in the event that EVs or FCVs fueled with electrolytic hydrogen achieve significant market penetration, the electricity supplied to fuel these vehicles will not come from the same average electricity mix that would be in place in the absence of these vehicles. Thus, an accurate analysis of the energy use and environmental impact of electricity-based vehicle fuels may attempt to determine the share of each technology amongst new generating capacity that would have to be added to meet the increased demand represented by the greatly expanded use of electricity for transportation. This new capacity is often referred to as the 'marginal electricity mix' for EVs or FCVs. As Wang (1999) discusses, the appropriate marginal electricity mix for vehicles powered by electricity-based fuels in a given region is determined by many factors, including:

> the excess electric generation capacity, the type of new additional power plants, the amount of total electricity needed by EVs … the time of day that EVs … are recharged, and the way in which electric utilities determine their power plant dispatch.[245]

Clearly then, there are large uncertainties involved in determining the proper marginal electricity mix, especially at a national level. Wang (1999) references several past studies on

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[244] See EIA, *AEO2006*.
[245] Wang (1999), Volume 1, p. 91.

Table 3-13: Makeup of Electricity Generation Mixes Included in this Study

	U.S. Average Mix[246]	*High Renewables Mix*[247]
Coal (%)	53.8%	49.0%
Petroleum (%)	1.9%	1.6%
Natural Gas (%)	17.9%	13.0%
Nuclear (%)	17.0%	16.4%
Biomass (%)	1.0%	2.2%
Other Renewables (%)	8.5%	17.8%
Share of CC for NG Plants (%)	53.15%	
Share of SC for NG Plants (%)	38.60%	
Share of IGCC for Coal Plants (%)	11.88%	
Share of IGCC for Biomass Plants (%)	3.00%	

EVs that attempt to estimate an appropriate marginal electricity mix, all of which focus on a specific region of the country and assume a specific number of EVs were introduced.[248] However, as the WtW analysis performed by this study focuses on a national level and does not make assumptions about the number of vehicles of any type, this study uses the U.S. average and high renewables mixes to illustrate two possible representative electricity mixes. Clearly, a marginal electricity mix would be preferable and this presents one opportunity for further refinement of the analysis presented by this study. Additionally, if the findings of this study were to be applied to a specific region, the electricity generation mix ought to be altered to reflect the particular mix in that region.

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[246] As per Reference Case from EIA, *AEO2006*. Share of mix for coal, petroleum, natural gas and nuclear from Table A8, p. 147. Share of mix for biomass from Table D7, p. 191 (values reported for 2020 and 2030; value for 2025 is average of the two).

[247] Assumes mix is adjusted from US Average Mix. The share of reductions in fossil and nuclear capacity due to increase in renewables is proportional to the reductions predicted in the EIA's analysis of the effects of a 10% Federal Renewable Portfolio Standard. See EIA. *Analysis of 10-precent Renewable Portfolio Standard.* (Washington D.C.: EIA, May 2003).

[248] See, for example, ANL, et al., *Total Energy Cycle Assessment of Electric and Conventional Vehicles: An Energy and Environmental Analysis, Vol. II: Appendices to Technical Report* (Washington, D.C.: ANL, Jan. 1998).

3.4.3 Utilizing Remote Stranded Renewables

In addition to the two representative electricity mixes discussed above, this study also analyzes four production pathways that specifically utilize electricity from remote renewable resources. These pathways are meant to represent the use of large-scale renewable resources that are located in remote areas far from existing transmission infrastructure and/or demand centers – i.e., 'stranded' renewable potential. Examples include the 'solar bonanza' of the desert Southwest[249] and the vast wind potential located throughout the Great Plains region,[250] as well as offshore wind, wave or tidal potential. These and other areas may have significant renewable energy potential but are difficult to economically utilize due to the high costs of extending transmission lines to the area and the large energy losses associated with transmitting the electricity to population centers via traditional alternating current (AC) transmission lines. The EIA estimates that aboveground AC transmission lines capable of transmitting one gigawatt (GW) of capacity cost upwards of $1 million per mile to install, not including the cost to purchase right-of-way – i.e., the cost of land and the legal right to use and service the land on which the transmission line would be located.[251] Furthermore, long-

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[249] For a discussion of a Southwest solar-based hydrogen production scenario, see Mazza, Patrick and Roel Hammerschlag. *Carrying the Energy Future: Comparing Hydrogen and Electricity for Transmission, Storage and Transportation*. (Seattle, WA: Institute for Lifecycle Environmental Assessment, June 2004). pps. 10-12.

[250] For a discussion of a Great Plains wind-based hydrogen production scenario, see the multiple works of William C. Leighty: Leighty, William C, et al.: *Compressorless Hydrogen Transmission Pipelines Deliver Large-scale Stranded Renewable Energy at Competitive Cost*. (Presented at Power Gen Renewable Energy and Fuels, Los Vegas, NV, April 2006); and Leighty, William C. and Geoffrey Keith. *Transmitting 4,000 MW of New Windpower from North Dakota to Chicago: New HVDC Electric Lines or Hydrogen Pipeline* (Presented at the International Conference on Hydrogen Age of Asia, Tokyo, Nov. 2001).

[251] See EIA. "Typical Costs and Capacity of New Transmission Lines". *Upgrading Transmission Capacity for Wholesale Electric Power Trade*. June 2006. <http://www.eia.doe.gov/cneaf/pubs_html/feat_trans_capacity/table2.html>. Accessed 5/2/2006. The EIA reports that 230 kilovolt transmission lines with a nominal capacity of 1,060 MW cost between $725,000 and $1,107,000 in 2006 dollars, not including right-of-way costs, which can be quite significant. Underground lines cost 4-5 times as much. (Costs reported in 1995 dollars and converted to 2006 dollars assuming a 2.54% average yearly inflation rate since 1995. See <http://inflationdata.com/Inflation/Inflation_Rate/HistoricalInflation.aspx>).

distance transmission of electricity over AC transmission lines results in significant transmission losses.

HVDC Transmission Lines vs. Gaseous Hydrogen Pipelines:

Two options have been proposed to utilize these vast but stranded remote renewable resources while mitigating transmission losses and offering lower infrastructure costs: transmitting the energy via high voltage direct current (HVDC) transmission lines; and producing gaseous hydrogen via electrolysis on site and then transmitting the energy via hydrogen pipelines.[252]

HVDC lines are typically utilized to transmit large amounts of power (>500 megawatts [MW]) over long distances (>300 miles) or to transmit power underwater.[253] In these applications, HVDC lines are generally less expensive to install than high voltage AC lines of similar capacity and result in much lower transmission losses. HVDC lines with a capacity of 2 GW cost approximately $500,000 per mile to install (including right-of-way),[254] about a quarter of the cost of an AC line of similar capacity. For shorter distances, however, the AC-DC converter stations required at each point of interconnection with an AC network as well as the expensive power control electronics required to operate HVDC lines make HVDC transmission uneconomical.[255] For example, AC-DC converter stations cost roughly a quarter of a million dollars each, greatly increasing the overall system price for an HVDC

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[252] See, for example, Leighty and Keith (2001).
[253] HVDC lines are also used to link to asynchronous AC networks. See Rudervall, Roberto, et al. *High Voltage Direct Current (HVDC) Transmission Systems Technology Review Paper*. (Presented at "Energy Week 2000", Washington, D.C., March 2000). pps. 17-18.
[254] Leighty and Keith (2001), p. 22. Assumes two 1 GW circuits installed on a single set of towers. Cost reported as $568,000 per mile (in 2001 dollars) for an HVDC line 1,000 miles long. An AC line of 2 GW capacity would require two towers and would cost at least four times as much per mile (i.e., >$2 million per mile) as an HVDC line at that capacity.
[255] Rudervall, et al. (2000) report that at distances over 650 km (~400 miles), HVDC is generally cheaper than comparable high voltage AC lines. See p. 6.

line.[256] Clearly then, for short distances (less than about 300 miles), the price of the converter stations dominates the lower price per mile of HVDC lines relative to AC lines.[257] Additionally, HVDC lines can transmit more power over the same size conductor than AC lines. They are thus more compact than equivalent AC lines, reducing the size of the right-of-way required to transmit the same amount of power.[258] This further reduces the installation costs as well as the environmental footprint of HVDC relative to AC.

For these reasons, HVDC has been employed throughout the world to transmit large amounts of power across long distances.[259] Unlike fossil and nuclear-fueled power plants, which can generally be situated relatively close to demand centers, renewable power facilities must be located wherever the renewable energy potential is located. As such, HVDC lines have frequently been used to transmit power from these renewables – often large hydropower projects – to demand centers.[260]

This study thus includes a remote renewables via HVDC pathway representing the transmission of electricity from remote stranded renewables to demand centers via HVDC lines for use in battery electric and plug-in hybrid vehicles. For this pathway, electricity from renewables are transmitted over 1,000 miles on average to demand centers over HVDC lines which experience line losses of 0.64% per 100 miles.[261] An additional energy loss of

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[256] Leighty and Keith (2001) report a cost of $520,000,000 (2001 dollars) for two converter stations. See p.22.
[257] Assuming aprox. $2 million per mile for 2 GW AC lines and $500,000 per mile for 2 GW HVDC lines plus $500 million for two AC-DC converter stations, the break-even distance for HVDC is >333 miles.
[258] See Rudervall, et al. (2000). p. 17.
[259] See ibid. p. 19, for a map of many of the world's HVDC lines as well as pps. 10-17 for discussion of several specific HVDC systems.
[260] For example, the Itaipu HVDC Transmission Project in Brazil links the massive 12,600 MW Itaipu hydroelectric plant, shared by Brazil and Paraguay, to Sao Paolo, in the heart of Brazil's industrial centre, a distance of approximately 500 mi (~800 km). See ibid. pps. 10-11. Another example is the Nelson River DC Transmission System, which also connects a large hydropower system, this time in northern Manitoba, Canada with the city of Winnipeg over 550 mi (895 km) away. See Manitoba Hydro. "Nelson River DC Transmission System". *Our Facilities*. <http://www.hydro.mb.ca/our_facilities/ts_nelson.shtml>. Accessed 5/4/2006.
[261] Leighty and Keith (2001) report HVDC line losses of 0.4% per 100 kilometers (62.13 mi) which is equivalent to .644% per mile. See p. 26.

0.75% is incurred at each AC-DC conversion station, one of which is assumed to be located at each end of the HVDC transmission line.[262] Thus, the overall transmission efficiency over 1,000 miles of HVDC lines (including two AC-DC converter stations) is 92.3%.[263]

Another potential option to utilize these remote renewable resources would be to use electricity generated by these renewables to create gaseous hydrogen via electrolysis of water on site and then transmit the hydrogen to demand centers via pipelines. Transmitting the energy from remote renewables in this manner has several advantages over using traditional AC or HVDC transmission lines. First, many renewables, including wind and solar, are intermittent resources – the wind doesn't blow at a constant rate and the sun only shines part of the day. This often makes synchronizing the electricity produced by these renewables with demand – which also varies throughout the day and year – a difficult task. This is especially true for HVDC lines, as electricity has to used when it arrives. The intermittent nature of these renewables also reduces the capacity factor[264] of the transmission infrastructure (i.e., HVDC lines or H2 pipelines) linking them to demand centers, which may make the transmission system uneconomical to operate.[265]

Transmitting the energy from these remote renewables as hydrogen via pipelines thus has the distinct advantage that the hydrogen can be 'packed' into the pipeline as it is generated by increasing the pressure in the pipeline and then utilizing the hydrogen at a

[262] ibid. reports 1.5% energy losses for two AC-DC converter stations or 0.75% each. See p. 26.
[263] i.e. (1-0.75)*(1-0.64)^(1000/100)*(1-0.75) = .9234
[264] Capacity factor denotes the percentage of the maximum capacity (of a power plant or transmission system, etc.) utilized on average. For example, a 100 MW (capacity) wind farm that operated at 30 MW on average would have a capacity factor of 30%. The transmission infrastructure must be sized to accept (nearly) the full capacity of the wind or solar farm, even though it will only be operating at this peak capacity on rare occasions. Otherwise, the energy produced at peak times must be curtailed and wasted as the transmission infrastructure will be unable to accept it.
[265] One option to increase the capacity factor of HVDC lines linking intermittent remote renewables like wind or solar to demand centers would be to include an interconnect to a hydropower or natural gas peaking plant to provide additional power when the intermittent resource is low.

slower rate. This provides a degree of energy storage in the transmission medium, which provides some ability to 'firm' the power produced by intermittent renewables. Energy analyst William Leighty reports that a 1,000 mi GH2 pipeline has a storage capacity between 20 gigawatt-hours (GWh) (for a 20 inch [in.] pipeline operating between 300-600 psi) and 214 GWh (for a 36 in. pipeline operating between 500 and 1,500 psi).[266] That presents a sizable storage capacity equivalent to up to 22 days of storage for the output of a 1,000 MW wind farm.[267]

While the pipeline itself thus presents significant storage potential, the throughput of the pipeline, and thus the amount of saleable hydrogen, drops significantly when it is utilized for storage. Therefore, a large degree of pipeline storage may not be economical. For example, natural gas pipelines, which can also be 'packed' to provide storage, are generally only utilized in this manner to compensate for temporary compression equipment outages.[268] Thus, pipeline storage may provide only some degree of limited 'firming' of intermittent renewable resources.

However, transmitting energy from remote renewables also opens up the possibility of low-cost, large-scale storage of hydrogen in geologic formations (e.g., solution-mined salt caverns, etc.) located along the pipeline route. Natural gas is often stored, either at the upstream or downstream end of a pipeline, in this manner, and it would be feasible to similarly store GH2.[269] Utilizing large-scale underground storage would thus render inherently intermittent renewables 'dispatchable' – i.e., the energy from the intermittent

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[266] See Leighty et al. (2006), pps. 25-26.
[267] ibid. p. 26. Assumes a 40% capacity factor for the wind farm.
[268] ibid. p. 26.
[269]More than 1,000 tons of GH2 are stored in a several solution-mined salt caverns in Tees County, UK. ChevronPhillips has also operated a cavern for over 20 years, storing over 2,500 tons of GH2. See ibid. p. 26. The H_2 molecule *is* much smaller than a natural gas (CH_4) molecule, however, and this could limit the number of geological formations suitable for GH2 storage.

source could be stored as GH2 and then transmitted to demand centers when needed. Large geological structures could also provide long-term storage to help synchronize seasonal variations in wind or solar production with seasonally varying demand.[270]

Finally, the National Renewable Energy Laboratory has begun exploring the use of wind turbine towers themselves for hydrogen storage.[271] The towers could potentially provide hydrogen storage capacity and 'firming' ability at little extra cost to manufacture and install compared to normal towers. Clearly, transmitting energy from remote renewables as hydrogen opens up several possibilities for cheap energy storage to 'firm' and render 'dispatchable' inherently intermittent renewable resources.[272] These storage options could greatly improve the capacity factor, and thus the economics, of the pipeline, as an upstream storage option would allow the capacity of the pipeline to be downsized to approximately the average output of the wind farm, for example, with the storage accepting extra energy when the wind is howling and making up the difference when the wind farm is becalmed. Thus, the ability to store hydrogen presents a major advantage over transmission as electricity via HVDC lines.[273]

Transmitting energy over pipelines also has the advantage that pipelines require a much smaller right-of-way to transmit the same amount of energy as HVDC lines. While

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[270] Demand usually experiences seasonal peaks in the winter and summer when heating and air conditioning needs are greatest.

[271] The National Renewable Energy Laboratory is also exploring the potential utilizing wind turbine towers for hydrogen storage. See Kottenstette, R. and J. Cotrell. *Hydrogen Storage in Wind Turbine Towers: Cost Analysis and Conceptual Design*. (Golden, CO: National Renewable Energy Laboratory, Sept. 2003).

[272] See Leighty, et al. (2006), pps. 29-31 for a discussion of various hydrogen storage options that could be utilized by the remote renewables via GH2 pipeline pathway.

[273] To be fair, several options *are* potentially available to store energy from intermittent renewables transmitted as electricity. The largest and cheapest options – i.e., compressed air or pumped hydro storage – are limited by the availability of suitable geological formations. However, some options – i.e., flow battery storage – may be able to scale adequately to provide similar 'firming' capabilities for energy from intermittent renewables transmitted as electricity. See Mazza and Hammerschalg (2004), pps. 15-17 for a comparison of hydrogen and other storage options.

HVDC lines are strung overhead on towers, which typically require 150-200 feet of right-of-way,[274] GH2 pipelines are located underground and require only a few yards of right-of-way to install, service and maintain. This greatly reduces the permitting and land costs as well as the environmental impact of siting GH2 pipelines compared to transmission lines. Underground pipelines may also prove more palatable to the public than overhead transmission lines and are more secure from weather-related damage, reducing operating and maintenance costs relative to aboveground transmission lines.[275]

The final main advantage of GH2 pipelines is the relative ease at which they can facilitate the collection of energy from multiple distributed renewable (and non-renewable) energy sources along the pipeline pathway. Whereas HVDC lines require expensive power control electronics and potentially an AC-DC converter station to connect 'spurs' to various energy sources, adding a delivery node to a GH2 pipeline would be simple, inexpensive, and amenable to a wide range of capacities.[276] All that would be required would be a small-diameter pipeline spur, a boss in the main pipeline, a shut-off valve, meter, delivered gas quality monitor and a compressor (if necessary).[277] This opens up the possibility for multiple renewable (or non-renewable) energy sources to be synergistically coupled on the same pipeline. Energy analysts William Leighty and Geoffrey Keith discuss the potential wind power-biomass synergy available in the Great Plains region – i.e., biomass (switchgrass, agricultural waste, etc.) could be collected and stored at various biomass-fired power plants along the pipeline and then used to produce hydrogen through electrolysis and/or gasification

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[274] Leighty and Keith, (2001), p.21.
[275] Weather related damage may prove more than a minor concern when linking the vast wind potential of the Great Plains – i.e., 'Tornado Alley' – over long distances to population centers.
[276] See Leighty and Keith (2001), pps. 12-13.
[277] ibid. pps. 12-13.

to compensate for drops in wind power production.[278] Such a scenario could greatly increase the capacity factor of the pipeline and help 'firm' the intermittent wind resource.

However, these advantages come at a significant cost, both in terms of energy losses and infrastructure costs. When used to transmit energy from remote stranded renewables, hydrogen acts as a carrier for electrical energy: that is, it is produced from electricity at the upstream end, and then eventually converted back into electricity (and sometimes useful heat) by a fuel cell at the downstream terminus of the pathway. Both the conversion of electricity into hydrogen and the conversion of hydrogen back into electricity accrue large energy losses. The production of hydrogen via electrolysis of water loses about 25% of the energy contained in the input electricity.[279] Conversion of hydrogen to electricity in low-temperature, lightweight fuel cells suitable for use in vehicles (i.e., proton exchange membrane or PEM fuel cells) also incurs a loss of around 50% of the energy contained in the hydrogen.[280] Thus, not including transmission losses (which are roughly comparable between HVDC and GH2 pipelines over long distances), only about 37.5% of the energy contained in the electricity produced by remote renewables is converted by the PEM fuel cell back to useful electricity at the end of the hydrogen pathway. Additional energy losses are incurred for compressing or liquefying the hydrogen for storage on-board FCVs.

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[278] See Leighty and Keith (2001), p. 48. Gasification of biomass presents a particularly synergistic option, as oxygen produced from electrolysis at wind farms could be pipelined to near-by biomass gasification facilities and used in oxygen-blown gasifiers. This would improve the economics of both the wind and biomass gasification plants. Coupling hydrogen production from coal gasification plants with the pipeline also presents another synergistic option, as such plants could also take advantage of oxygen produced at the wind power/electrolysis facilities. See ibid. p. 48 as well.

[279] See Ivy, Johanna. *Summary of Electrolytic Hydrogen Production*. (Golden, CO: National Renewable Energy Laboratory, Sept 2004). p. 10. Ivy reports that as of December 2003, commercially available electrolyzer efficiencies ranged from 56-73%. She reports that the industry's future efficiency goal is 78%. I this assume that by 2025, the average efficiency of commercially available systems reaches 75%, a value midway between the maximum of currently available systems and the future industry goal. ANL, *GREET 1.7 Beta* assumes a similar efficiency of 74% is reached by 2020. See 'Fuel_Prod_TS' worksheet.

[280] Weiss, Malcolm A., et al. *Comparative Assessment of Fuel Cell Cars*. (Cambridge, MA: Massachusetts Institute of Technology, Feb. 2003). p. 21. This figure includes losses from auxiliary systems requisite to the functioning of the fuel cell.

High temperature stationary fuel cells suitable for electric power generation (i.e., solid oxide or molten carbonate fuel cells) can reach slightly higher electrical efficiencies of around 55%.[281] They also co-generate useful 'waste' heat that can be utilized to create process steam or heat for industrial applications or space conditioning, boosting the overall thermal efficiency of high temperature fuel cells to approximately 80%[282]. However, even given this high overall thermal efficiency, only about 60% of the energy contained in the electricity produced by remote renewables is converted back to useful electricity (and heat) at the end of this pathway. Clearly then, while transmitting energy as hydrogen has several benefits, as discussed above, it incurs significant energy losses that may preclude hydrogen as a viable energy transfer medium.

In addition to large energy losses, transmitting energy via hydrogen pipelines also incurs larger economic costs than transmitting the same amount of energy as electricity via HVDC transmission lines. As mentioned above, HVDC transmission lines with a capacity of 1-2 GW cost approximately $500,000 per mile to install.[283] An HVDC transmission system also requires two (or more) AC-DC conversion stations to interface with the AC transmission grid. Each costs around $260 million.[284] Thus, the total system costs to transmit 1-2 GW of electricity from remote renewables 1,000 miles via HVDC would be just over $1 billion.[285]

Installing a 1000 mile, 20-inch diameter hydrogen pipeline would cost approximately $900,000 per mile[286] and would have a capacity of 1.2 GW.[287] High-pressure output

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[281] Energy Efficiency and Renewable Energy, Office of. "Fuel Cells". *Hydrogen, Fuel Cells & Infrastructure Technologies Program*. April, 2006.
[282] ibid.
[283] Leighty and Keith (2001), p. 22. Actual reported value is $568 million for 1,000 miles of HVDC lines on a single set of towers.
[284] ibid. p. 22. Reported value is $520 million for two converter stations.
[285] Actual value: $1.088 billion.
[286] Leighty et al. (2006) reports a cost of $29 per inch diameter per meter length for hydrogen pipelines. That amounts to a cost of $46,571 per inch-mile or $933,420 per mile. This is roughly consistent with the natural gas

electrolyzers at the upstream end would add nearly $400 million[288] more to the cost of the system while the high temperature fuel cell power plant needed to turn the hydrogen back into useful electricity at the downstream end would cost a sizable $2.9 billion.[289] Note that while the capacity of the pipeline is 1.2 GW, only 80% of this energy is converted to useful energy at the fuel cell power plant. Thus, this system actually transmits just under 1 GW of useful energy from the wind farm to the fuel cell power plant's gates. The system costs to transmit around 1 GW of useful energy from remote renewables 1,000 miles via GH2 pipeline would total to just over $3.6 billion, over three times more than the cost to transmit the same amount of energy via HVDC.[290] While the increased infrastructure cost may be somewhat offset by the ability of hydrogen pipelines (potentially in conjunction with geologic or other storage facilities) to provide more 'firm' energy that better coincides with periods of demand (and thus fetches a higher price), it is clear that the advantages of hydrogen pipelines over HVDC transmission lines come at a high cost. Table 3-14 below summarizes the advantages and disadvantages of HVDC transmission lines and GH2 pipelines.

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pipeline costs ($43,700 per inch-mile) reported by the engineering consulting firm, R.W. Beck, inc. See R.W. Beck, Inc. "Natural Gas Transmission Pipeline Construction Cost". *Oil and Gas Bulletin*. (R.W. Beck, Inc., 2003). p. 2.

[287] Leighty, et al. (2006). p. 6.

[288] Actual value is $396 million. ibid. p. 4. Reported value is $330/kW capacity and is for 1,500 psi output electrolyzers. Leighty, et al. (2006) discusses the use of high pressure output electrolyzers to feed long-distance GH2 pipelines, thus reducing or eliminating the need for compressors along the pipeline. Currently, no manufacturers offer electorlyzers that high pressure output, but Leighty, et al. are confident, based on industry consensus and USDA goals that such electorlyzers will be available, and at MW scale, after 2010. See p. 4. This study does *not* assume that high pressure electrolyzers are used, as per ANL, *GREET 1.6,* and instead assumes that GH2 is propelled down the pipeline with compressors.

[289] Leighty and Keith (2001), p. 22.

[290] Actual value is $3.629 billion, or 3.336 times the cost of an equivalent HVDC system. Leighty and Keith (2001) ultimately conclude that electricity from 4,000 MW of wind power transmitted over 1,000 miles from the Great Plains to Chicago would sell for approximately 6 cents/kWh if transmitted over HVDC lines and between 14 and 18 cents/kWh if transmitted via GH2 pipelines to high temperature fuel cell power plants (see p. 27). This is thus consistent with this study's analysis: i.e. transmitting the same amount of energy via GH2 pipeline costs around 3 times as much as transmitting the energy via HVDC.

Table 3-14: Comparison of Long Distance Energy Transmission Options for Utilizing Remote Renewables

	AC Trans. Lines	HVDC Trans. Lines	GH2 Pipeline
Advantages	- Easy integration with AC transmission grid; - Easier to collect energy from dispersed sources than HVDC	- Smaller right-of-way than AC; - Lower transmission loss than AC; - Lower capital costs than AC and GH2	- Energy storage potential in pipeline; - Potential to integrate with geologic or other storage facility; - Can deliver more 'firm' power; - Easier to collect energy from dispersed sources than HVDC; - Smaller right-of-way than AC or HVDC
Disadvantages	- Very high transmission losses over long distances; - Very high capital cost; - 'Real-time' delivery of energy	- Requires expensive power control electronics and AC-DC converter stations to integrate with AC grid; - 'Real-time' delivery of energy	- Large energy losses; - Very high capital cost
Cost to transmit approx. 1-2 GW over 1,000 miles	- $2 million per mile; for **- $2 billion total**	- $568,000 per mile; plus - $520 billion for two AC-DC converter stations; for **- $1.09 billion total**	- $29 per in.-m ($46,671 per in.-mi) for $933.4 million per mile; plus - $396 million for high-pressure output electrolyzers; plus - $2.3 billion for high temp. fuel cell power plant; for **- $3.63 billion total**

This study includes three fuel production pathways representing the transmission of energy from remote renewables via GH2 pipelines. In the first two, gaseous hydrogen is produced at the site of the remote renewables via electrolysis of water and then transmitted via GH2 to fueling stations in demand centers. There the GH2 coming out of the pipeline is either compressed or liquefied and then stored for fueling of FCVs (see 3.2.2 above). In the third pathway, GH2 is also produced via electrolysis at the site of the remote renewables and then transmitted to demand centers. There, it is converter back to electricity at high temperature fuel cell power plants that co-generate heat or steam for use in adjacent industrial processes. The electricity is then used as a fuel for battery electric or plug-in hybrid vehicles. This study assumes that high temperature solid oxide or molten carbonate fuel cells are utilized at the fuel cell power plant operating at an average electricity conversion efficiency of 55%.

This study also assumes that some of the waste heat generated by the fuel cell power plant is captured to produce steam or heat for export, boosting the overall thermal efficiency of the power plant to 80%. 454,545 Btu of steam are thus assumed to be produced for every mmBtu of electricity produced by the fuel cell power plant. As with steam co-produced for export during the production of hydrogen via steam methane reforming of natural gas (see Section 3.2.2 above), this study allocates an energy use and emissions credit for the steam co-generated at the fuel cell power plant. This study calculates this credit using two methods: the Displacement Method and the Energy Content Method (both are discussed in Section 3.3.4 above). For the Displacement Method, the steam produced at the fuel cell power plant is assumed to displace steam produced at a natural gas-fired industrial boiler. The energy use and emissions for the fuel cell power plant and the upstream stages that feed it (i.e., GH2 pipelining) are thus reduced by the total energy use and emissions associated with producing the natural gas-based steam offset by the exported steam from the fuel cell power plant. As the name implies, for the Energy Content Method, the credit is based on the energy contents of the steam and electricity. That is, the energy use and emissions associated with the fuel cell power plant and its upstream stages are divided proportionate to the energy contents of the two energy products (electricity and steam), thus reducing the energy use and emissions associated with the electricity produced at the power plant. Note that calculating the credit for steam production with the Displacement Method actually results in negative values for WtP fossil energy, GHG emissions and several criteria pollutant emissions (see Table 3-16 below). This is due to the fact that the fossil energy use and emissions associated with steam production via natural gas offset by the steam co-produced at the fuel cell plant is actually larger than the fossil energy use and emissions associated with the power plant and its upstream stages. This again illustrates the large differences in calculated WtP energy use and emissions values resulting from the use of different credit allocation methods. In general, this study considers credit allocation methods that do not result in negative WtP energy use and emissions values more appropriate, but both methods are included as some readers may consider credits calculated by the Offset Method more accurate or relevant.

3.4.4 Summary of Energy Use and Emissions Assumptions and Results for Electricity-based Fuel Production Pathways

Table 3-15 below summarizes the major assumptions used to calculate energy use and emissions for the electricity-based fuel pathways described above. Table 3-16 summarizes energy use and emissions results for electricity-based WtP fuel production stages. Additionally, several of the fuel production pathways considered in previous sections are combined with the electricity pathways to model combined WtP fuel pathways for plug-in hybrid electric vehicles. These WtP results are presented in Table 3-17 below. Note that biomass-based fuels are given a CO_2 'credit' for the amount of CO_2 contained in the fuel that is derived from biomass, as this CO_2 was absorbed from the atmosphere during plant photosynthesis. Thus, the WtP biomass-based fuel pathways in Table 3-17 below may show negative values for WtP CO_2 emissions.

Table 3-15: Key Assumptions for Electricity-based Fuel Production Pathways

Assumption	*Value*
Coal Mining and Cleaning-	
Coal mining and cleaning efficiency (%)	99.3%
Share of surface mining operations (%)	67.0%
CH4 losses – surface / underground mines (g/mmBtu coal mined)	236.0 / 31.2
Non-combustion emissions	
PM10 emissions – surface / underground mines (g/mmBtu coal)	177.8 / 80.3
VOC emissions – cleaning (g/mmBtu coal)	6.9
PM10 emissions – cleaning (g/mmBtu coal)	3.3
SO_x emissions – cleaning (g/mmBtu coal)	5.8
Share of process fuels – mining and cleaning (%)	
Residual oil / Diesel fuel	7.0% / 56.0%
Gasoline / Natural gas	3.0% / 1.0%
Coal / Electricity	2.8% / 5.1%
Coal Transportation-	
Share of coal transported by mode (%)*	
Barge	10.0%
Rail	90.0%
Average trip distance for petroleum transported by mode (mi)	
Barge	330
Rail	440
Uranium Mining and Enrichment	
Uranium mining efficiency (%)	99.5%
Share of process fuels – mining (%)	
Residual oil / Diesel fuel	1.0% / 22.0%
Gasoline / Natural gas	5.0% / 43.0%
Electricity	29.0%
Uranium enrichment efficiency (%)	95.8%
Share of process fuels – mining (%)	
Natural gas / Electricity	3.0% / 97.0%
Uranium Transportation	
Share of uranium transported to enrichment by mode (%)*	
Rail	100.0%
Truck	20.0%

*Table 3-15: Key Assumptions for Electricity-based Fuel Production Pathways (***Continued***)*

Assumption	*Value*
Average trip distance for uranium transported by mode (mi)	
Rail	100
Truck	20
Share of uranium transported to power plant by mode (%)*	
Truck	100.0%
Average trip distance for uranium transported by mode (mi)	
Truck	200
Residual Oil Transportation	
Share of residual oil transported by mode (%)*	
Ocean tanker	11.5%
Barge	40.0%
Pipeline	56.4%
Rail	5.0%
Average trip distance for petroleum transported by mode (mi)	
Ocean tanker	3,000^
Barge	340^
Pipeline	400
Rail	800
Natural Gas Transportation	
Share of natural gas imported from overseas as LNG	12.9%
Share of natural gas transported by mode (%)*	
Ocean tanker	12.9%
Pipeline	100.0%
Average trip distance for natural gas transported by mode (mi)	
Ocean tanker	5,000^
Pipeline	375
Biomass Transportation	
Share of biomasss transported by mode (%)*	
Truck	100.0%
Average trip distance for biomass transported by mode (mi)	
Truck	50^

*Table 3-15: Key Assumptions for Electricity-based Fuel Production Pathways (***Continued***)*

Assumption	*Value*
Electricity Generation	
Electricity conversion efficiencies (%)	
Petroleum-fired steam turbine plant	34.8%
Natural gas-fired steam turbine plant	34.8%
Natural gas-fired simple cycle (combustion turbine) plant	34.0%
Natural gas-fired combined cycle plant	60.0%
Coal-fired pulverized coal (steam turbine) plant	35.5%
Coal-fired integrated gasification combined cycle (IGCC) plant	41.5%
Biomass-fired steam turbine plant	33.9%
Biomass-fired integrated gasification combined cycle (IGCC) plant	41.5%
Electricity generation combustion emissions	See Table 3-12
Electricity generation mix and shares of combustion technologies	See Table 3-13
Electricity from Remote Renewables	
Electricity via HVDC transmission lines	
HVDC transmission line losses (% per 100 mi)	0.64%
AC-DC converter station energy losses (%)	0.75 %
Electricity via GH2 pipelines and high temp fuel cell power plants	
GH2 production via electrolysis efficiency (%)	75.0%
High temp fuel cell electricity conversion efficiency (%)	55.0%
High temp fuel cell overall thermal efficiency (%)	80.0%
Steam co-produced at fuel cell power plant (Btu/mmBtu electricity)	454,545
Transmission distance from remote renewables to demand center (mi)	1,000
Hydrogen Production from Electricity and Remote Renewables	
GH2 production via electrolysis efficiency (%)	75.0%
GH2 compression efficiency – GH2 pipelined to station (%)	92.5%
GH2 compression efficiency – GH2 produced on site (%)	94.0%
LH2 production (liquification) efficiency at fueling stations (%)	70.0%
Share of process fuels – liquification (%)	
Electricity	100.0%
LH2 loss due to boiling off – liquification stage (g/mmBtu LH2)	15.8

* Transport mode shares may add up to more than 100% as fuels may be transported through multiple modes. Additionally, individual mode shares may exceed 100% as some fuels pass through the same type of mode during more than one leg of their journey.
^ Round-trip energy use and emissions for this transport mode are calculated – i.e. back-haul trips are assumed to be empty.

Table 3-16: Well-to-Pump Energy Use and Emissions Results for Electricity-based Fuel Production Pathways

(Btu or g/mmBtu of fuel available at fueling station pumps)	*Electricity from U.S. Average Mix*	*Electricity from High Renewables Mix*	*GH2 from Electrolysis at Fueling Stations with Electricity from U.S. Ave Mix*	*GH2 from Electrolysis at Fueling Stations with Electricity from High Renewables Mix*	*LH2 from Electrolysis at Fueling Stations with Electricity from U.S. Ave Mix*	*LH2 from Electrolysis at Fueling Stations with Electricity from High Renewables Mix*
Total Energy	1,552,615	1,420,208	2,567,134	2,381,947	3,541,052	3,305,399
Net Fossil Energy Ratio	0.67	0.77	0.45	0.52	0.32	0.38
Fossil Fuels	1,485,526	1,304,199	2,233,012	1,909,884	3,080,172	2,650,323
Petroleum	72,114	65,695	91,113	80,590	125,680	111,833
CO2	228,790	202,629	319,705	283,139	406,828	360,298
CH4	327.164	284.833	457.100	397.958	581.665	506.406
N2O	4.038	4.467	5.644	6.243	7.182	7.944
GHGs	236,913	209,995	331,053	293,432	421,269	373,395
VOC: Total	16.357	15.059	22.907	21.079	29.150	26.824
CO: Total	35.182	34.164	49.284	47.828	62.715	60.862
NOx: Total	202.279	185.045	282.957	258.789	360.067	329.312
PM10: Total	305.326	278.415	426.610	389.005	542.865	495.013
SOx: Total	225.805	205.723	315.497	287.435	401.474	365.765
VOC: Urban	0.449	0.374	0.643	0.535	0.818	0.680
CO: Urban	3.063	2.495	4.316	3.513	5.493	4.471
NOx: Urban	11.013	9.584	15.485	13.463	19.705	17.132
PM10: Urban	1.706	1.465	2.385	2.048	3.035	2.606
SOx: Urban	11.582	10.514	16.182	14.690	20.592	18.694

Table 3-16: Well-to-Pump Energy Use and Emissions Results for Electricity-based Fuel Production Pathways (**Continued**)

(Btu or g/mmBtu of fuel available at fueling station pumps)	*Electricity from Remote Renewables via HVDC*	*Electricity from Remote Renewables via H2 Pipeline and FC Plant (Displacement Method)*	*Electricity from Remote Renewables via H2 Pipeline and FC Plant (Energy Content Method)*	*GH2 from H2 via Electrolysis Pipelined from Remote Renewables*	*LH2 from H2 via Electrolysis Pipelined from Remote Renewables*
Total Energy	82,895	597,007	768,887	1,589,860	2,491,422
Net Fossil Energy Ratio	infinite	-1.79	31.87	4.43	1.00
Fossil Fuels	0	-558,150	31,381	225,719	999,666
Petroleum	0	7,078	6,511	16,817	48,392
CO2	0	-32,767	2,784	22,617	102,205
CH4	0.000	-57.637	3.950	32.272	146.010
N2O	0.000	-0.604	0.045	0.393	1.798
GHGs	0	-34,165	2,881	23,417	105,829
VOC: Total	0.000	-1.385	0.265	1.715	7.415
CO: Total	0.000	-24.359	1.601	5.190	17.468
NOx: Total	0.000	11.720	17.794	42.306	112.916
PM10: Total	0.000	1.238	2.554	28.473	134.609
SOx: Total	0.000	2.950	3.334	23.159	101.670
VOC: Urban	0.000	-0.402	0.028	0.037	0.197
CO: Urban	0.000	-6.277	0.272	0.250	1.324
NOx: Urban	0.000	1.232	3.281	0.899	4.750
PM10: Urban	0.000	-0.568	0.035	0.138	0.732
SOx: Urban	0.000	0.098	0.394	0.939	4.964

Table 3-17: Well-to-Pump Energy Use and Emissions Results for Combined Plug-in Hybrid Fuel Pathways

(Btu or g/mmBtu of fuel available at fueling station pumps)	*Electricity from US Ave Mix and Reformulated Gasoline for PHEV*	*Electricity from High Renewables Mix and Reformulated Gasoline for PHEV*	*Electricity from US Ave Mix and Low-Sulfur Diesel for PHEV*	*Electricity from High Renewables Mix and Low-Sulfur Diesel for PHEV*	*Electricity from US Ave Mix and E85 from Corn (Displacement Method)*	*Electricity from High Renewables Mix and E85 from Corn (Displacement Method)*	*Electricity from US Ave Mix and E85 from Herb. Biomass – Switchgrass (Energy Content Method)*	*Electricity from High Renewables Mix and E85 from Herb. Biomass – Switchgrass (Energy Content Method)*
Total Energy	1,124,280	1,074,649	1,088,621	1,039,119	1,324,377	1,275,326	1,370,727	1,321,345
Net Fossil Energy Ratio	1.00	1.12	1.04	1.16	0.83	0.91	1.10	1.25
Fossil Fuels	999,725	894,835	964,390	859,773	1,201,277	1,097,611	905,609	802,207
Petroleum	113,017	109,749	101,864	98,605	86,385	83,155	76,802	73,580
CO2	98,464	88,671	95,816	86,046	75,297	65,607	43,616	33,952
CH4	193.936	178.315	189.674	174.089	192.259	176.657	143.280	127.699
N2O	2.444	2.605	1.685	1.845	17.859	18.018	15.702	15.860
GHGs	103,295	93,223	100,322	90,274	84,871	74,903	51,493	41,551
VOC: Total	17.006	16.520	11.554	11.069	18.524	18.043	20.294	19.814
CO: Total	26.149	25.768	24.364	23.983	42.609	42.232	24.635	24.259
NOx: Total	105.452	99.000	101.946	95.510	134.858	128.475	115.843	109.477
PM10: Total	121.554	111.480	118.083	108.033	171.892	161.925	122.328	112.386
SOx: Total	97.674	90.157	95.772	88.273	100.732	93.297	89.341	81.923
VOC: Urban	3.767	3.739	1.727	1.699	1.554	1.526	1.545	1.518
CO: Urban	3.790	3.581	3.429	3.221	2.293	2.084	2.031	1.823
NOx: Urban	8.688	8.158	8.116	7.587	6.277	5.749	5.585	5.058
PM10: Urban	1.650	1.559	1.515	1.425	0.881	0.791	0.893	0.803
SOx: Urban	8.676	8.277	8.101	7.702	5.241	4.846	5.306	4.912

Table 3-17: Well-to-Pump Energy Use and Emissions Results for Combined Plug-in Hybrid Fuel Pathways (**Continued**)

(Btu or g/mmBtu of fuel available at fueling station pumps)	*Electricity from US Ave Mix and E85 from Herb. Biomass – Waste (Energy Content Method)*	*Electricity from High Renewables Mix and E85 from Herb. Biomass – Waste (Energy Content Method)*	*Electricity from US Ave Mix and E85 from Woody Biomass – Hybrid Poplar (Energy Content Method)*	*Electricity from High Renewables Mix and E85 from Woody Biomass – Hybrid Poplar (Energy Content Method)*	*Electricity from US Ave Mix and E85 from Woody Biomass – Waste (Energy Content Method)*	*Electricity from High Renewables Mix and E85 from Woody Biomass – Waste (Energy Content Method)*
Total Energy	1,328,591	1,279,142	1,409,625	1,361,003	1,395,232	1,345,785
Net Fossil Energy Ratio	1.16	1.31	1.14	1.29	1.16	1.31
Fossil Fuels	865,006	761,593	877,979	775,221	863,902	760,493
Petroleum	65,672	62,110	74,253	71,052	64,677	61,115
CO2	43,181	33,674	45,946	36,342	49,896	40,389
CH4	137.220	121.646	138.799	123.314	137.247	121.674
N2O	4.584	4.583	5.885	6.043	4.946	4.946
GHGs	47,484	37,649	50,686	40,805	54,312	44,477
VOC: Total	19.445	18.942	20.140	19.663	19.451	18.949
CO: Total	20.736	20.246	23.639	23.265	20.931	20.442
NOx: Total	97.301	90.554	105.618	99.291	97.042	90.295
PM10: Total	120.840	110.951	121.683	111.803	121.002	111.113
SOx: Total	87.336	79.926	98.095	90.723	96.764	89.354
VOC: Urban	1.505	1.477	1.525	1.497	1.503	1.475
CO: Urban	1.776	1.564	1.821	1.613	1.773	1.561
NOx: Urban	5.337	4.809	5.408	4.884	5.332	4.804
PM10: Urban	0.857	0.768	0.875	0.786	0.862	0.773
SOx: Urban	5.216	4.822	5.267	4.876	5.211	4.818

***Table 3-17: Well-to-Pump Energy Use and Emissions Results for Combined Plug-in Hybrid Fuel Pathways* (Continued)**

(Btu or g/mmBtu of fuel available at fueling station pumps)	*Electricity and GH2 via Electrolysis at Fueling Stations from US Ave Mix Electricity*	*Electricity and GH2 via Electrolysis at Fueling Stations from High Renewables Mix Electricity*	*Electricity and LH2 via Electrolysis at Fueling Stations from US Ave Mix Electricity*	*Electricity and LH2 via Electrolysis at Fueling Stations from High Renewables Mix Electricity*	*Electricity from US Ave Mix and GH2 from NA Natural Gas via Central SMR*	*Electricity from High Renewables Mix and GH2 from NA Natural Gas via Central SMR*	*Electricity from US Ave Mix and LH2 from NA Natural Gas via Central SMR*	*Electricity from High Renewables Mix and LH2 from NA Natural Gas via Central SMR*
Total Energy	2,198,188	2,032,154	2,817,745	2,817,745	935,612	879,614	1,296,310	1,247,784
Net Fossil Energy Ratio	0.51	0.59	0.40	0.40	1.12	1.24	0.79	0.83
Fossil Fuels	1,961,223	1,689,638	2,500,143	2,500,143	891,716	809,274	1,271,146	1,204,487
Petroleum	84,201	75,171	106,191	106,191	38,851	36,007	36,295	33,939
CO2	286,638	253,854	342,061	342,061	148,209	137,152	168,004	158,422
CH4	409.823	356.798	489.065	489.065	227.257	209.415	244.012	228.562
N2O	5.060	5.597	6.038	6.038	1.819	2.000	2.327	2.484
GHGs	296,813	263,082	354,203	354,203	153,545	142,170	173,849	163,992
VOC: Total	20.538	18.899	24.509	24.509	7.445	6.892	7.444	6.965
CO: Total	44.187	42.881	52.731	52.731	22.136	21.695	26.642	26.260
NOx: Total	253.691	232.022	302.744	302.744	104.687	97.379	99.044	92.711
PM10: Total	382.486	348.770	456.442	456.442	129.467	118.096	113.984	104.130
SOx: Total	282.865	257.706	337.559	337.559	97.224	88.738	86.884	79.531
VOC: Urban	0.576	0.479	0.688	0.688	0.238	0.205	0.235	0.206
CO: Urban	3.870	3.150	4.618	4.618	1.784	1.541	1.610	1.400
NOx: Urban	13.884	12.070	16.568	16.568	6.888	6.277	4.685	4.156
PM10: Urban	2.139	1.836	2.552	2.552	0.761	0.660	0.665	0.577
SOx: Urban	14.508	13.171	17.313	17.313	5.048	4.598	4.212	3.823

Table 3-17: Well-to-Pump Energy Use and Emissions Results for Combined Plug-in Hybrid Fuel Pathways (**Continued**)

(Btu or g/mmBtu of fuel available at fueling station pumps)	***Electricity from US Ave Mix and GH2 from Non-NA Natural Gas via Central SMR***	***Electricity from High Renewables Mix and GH2 from Non-NA Natural Gas via Central SMR***	***Electricity from US Ave Mix and LH2 from Non-NA Natural Gas via Central SMR***	***Electricity from High Renewables Mix and LH2 from Non-NA Natural Gas via Central SMR***	***Electricity from US Ave Mix and GH2 from H2 via Electrolysis Pipelined from Remote Renewables***	***Electricity from High Renewables Mix and GH2 from H2 via Electrolysis Pipelined from Remote***	***Electricity from US Ave Mix and LH2 from H2 via Electrolysis Pipelined from Remote Renewables***	***Electricity from High Renewables Mix and LH2 from H2 via Electrolysis Pipelined from Remote***
Total Energy	1,041,229	984,987	1,312,521	1,263,987	1,576,495	1,520,451	2,150,023	2,064,671
Net Fossil Energy Ratio	1.00	1.09	0.78	0.82	1.46	1.66	0.85	0.97
Fossil Fuels	996,722	913,766	1,287,339	1,220,664	684,283	601,744	1,176,629	1,032,183
Petroleum	44,207	41,347	41,148	38,791	36,938	34,092	57,024	52,250
CO2	155,446	144,341	170,255	160,672	97,646	86,579	148,275	131,421
CH4	333.660	315.748	246.773	231.323	139.568	121.672	211.923	184.666
N2O	1.965	2.147	2.366	2.523	1.720	1.901	2.613	2.889
GHGs	163,062	151,637	176,170	166,312	101,110	89,724	153,536	136,195
VOC: Total	8.490	7.934	7.871	7.392	7.056	6.503	10.683	9.840
CO: Total	25.246	24.803	27.964	27.582	16.136	15.695	23.947	23.276
NOx: Total	129.273	121.932	129.330	122.996	100.601	93.287	145.519	134.380
PM10: Total	130.595	119.174	114.324	104.469	129.211	117.830	196.729	179.397
SOx: Total	106.043	97.521	93.548	86.193	96.894	88.402	146.840	133.906
VOC: Urban	0.226	0.193	0.235	0.206	0.191	0.159	0.293	0.244
CO: Urban	1.749	1.505	1.580	1.370	1.283	1.045	1.966	1.601
NOx: Urban	6.191	5.578	4.678	4.150	4.604	4.003	7.054	6.133
PM10: Urban	0.733	0.633	0.663	0.576	0.709	0.609	1.087	0.933
SOx: Urban	4.824	4.372	4.218	3.829	4.811	4.368	7.372	6.692

4. PUMP-TO-WHEELS VEHICLE SYSTEMS

The pump-to-wheels (PtW) portion of this study considers several different conventional and advanced vehicle propulsion systems, including spark-ignition (SI) and compression-ignition direct-injection (CIDI) internal combustion engine vehicles (ICEVs), fuel cell vehicles (FCVs) and battery electric vehicles (BEVs). Additionally, several of the SI, CIDI and fuel cell (FC) vehicle systems are combined with batteries, an inverter and an electric motor (if not already present) to represent both grid-independent hybrid electric vehicles (HEVs) and grid-connected, or plug-in hybrid electric vehicles (PHEVs). The full list of vehicle propulsion systems considered by this study and corresponding abbreviations are presented in Table 4.1 below.

Table 4-1: Vehicle Propulsion Systems and Corresponding Abbreviations

Fuel	*Vehicle Propulsion System*	*Vehicle Abbreviation*
Reformulated Gasoline	Spark-ignition internal combustion engine vehicle	SI RFG ICEV
	Spark-ignition internal combustion engine hybrid electric vehicle	SI RFG ICE HEV
	Spark-ignition internal combustion engine plug-in hybrid electric vehicle	SI RFG ICE PHEV
Low-sulfur Diesel	Compression-ignition direct injection internal combustion engine vehicle	CIDI LSD ICEV
	Compression-ignition direct injection internal combustion engine hybrid electric vehicle	CIDI LSD ICE HEV
	Compression-ignition direct injection internal combustion engine plug-in hybrid electric vehicle	CIDI LSD ICE PHEV
Compressed Natural Gas	Spark-ignition internal combustion engine vehicle	SI CNG ICEV
Liquefied Petroleum Gas	Spark-ignition internal combustion engine vehicle	SI LPG ICEV
Ethanol (E85)	Spark-ignition internal combustion engine vehicle	SI E85 ICEV
	Spark-ignition internal combustion engine plug-in hybrid electric vehicle	SI E85 ICE PHEV
Gaseous Hydrogen	Fuel cell vehicle	GH2 FCV
	Fuel cell plug-in hybrid electric vehicle	GH2 FC PHEV

Table 4-1: Vehicle Propulsion Systems and Corresponding Abbreviations (**Continued**)

Fuel	*Vehicle Propulsion System*	*Vehicle Abbreviation*
Liquid Hydrogen	Fuel cell vehicle	LH2 FCV
	Fuel cell plug-in hybrid electric vehicle	LH2 FC PHEV
Electricity	Battery electric vehicle	BEV
	Various plug-in hybrid vehicles	See above

4.1 The Baseline Vehicle

This study selected a 22 mile per gallon (mpg) SI ICEV fueled with reformulated gasoline (RFG) as its baseline vehicle. This vehicle and its mileage are representative of the average fuel economy of all light-duty vehicles[291] on the road in 2025 – i.e., the light-duty vehicle stock – as predicted by the EIA's business-as-usual forecast.[292] Thus, this baseline vehicle is meant to be representative of the average size and weight of all light-duty vehicles on the road in 2025 and reflects vehicle performance standards representative of typical North American vehicle consumer expectations. These performance standards are detailed in Figure 2-3 (see Section 2.3 above) and were developed for use in the GM, ANL, et al. (2001) WtW study by researchers at GM's Research and Development and Planning Center.[293]

The baseline vehicle is also assumed to meet Federal Tier 2, Bin 5 emissions standards (see Table 2-1, Section 2.3 above). Actual emissions values for the baseline vehicle are based on those published in GREET 1.6. These values were developed by ANL using the EPA's MOBILE6.2 model and the California Air Resource Board's EMFAC2002

[291] Light-duty vehicles are defined as vehicles less than 8,500 lbs and include cars, minivans, sports-utility vehicles and light trucks.
[292] See EIA *AEO2006,* p. 145, Table A7. New vehicle fuel economy in 2025 is higher -
[293] See GM, ANL, et al. (2001), Volume 3, pps. 2-8 to 2-9. These standards were subsequently used in the GM, ANL, et al. (2005) study as well. See pps. 57-58.

model (both are on-the-road vehicle emissions modeling software).[294] These emissions values represent on-the-road values for a vehicle mid-way through its full useful life (i.e., approximately 85,000 miles out of 150,000 miles expected useful life).[295] Emissions values are estimated for combustion emissions of VOC, CO, NO_x, PM10, CH_4, and N_2O as well as evaporative VOC emissions (representing evaporation and spillage of fuel during fueling and vehicle operation) and PM10 emissions from tire and break wear. Combustion emissions of SO_x and CO_2 are calculated based on the sulfur and carbon contents of the fuels. Energy use and emissions values for the baseline vehicle are presented in Table 4-3 at the end of this section.

4.2 Alternative Vehicles

This study considers several alternative vehicle propulsion systems, some of which are already in mass production today (i.e. diesel, CNG, LPG, E85 and hybrid electric vehicles), while others are still in development (i.e. FCVs, BEVs and PHEVs). Energy use and emissions values[296] for alternative vehicles are presented in GREET relative to the energy use and emissions for the baseline vehicle discussed above, excepting emissions for CIDI vehicles (see Table 4-2 below). Emissions values for CIDI vehicles are presented relative to a CIDI ICEV fueled with LSD (see Table 4-3).[297]

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[294] See GM, ANL, et al. (2005), p. 64.

[295] On-the-road vehicle emissions modeling is necessary because vehicles experience various emissions deterioration effects between the laboratory emissions tests used to certify new vehicles as complying with vehicle emissions standards and actual real-world on-the-road situations encountered after accumulating a certain amount of mileage. For this reason, state and local governments usually employ on-the-road emissions modeling software like MOBILE to estimate their inventory of mobile source (i.e., vehicle) emissions. See Wang (1999), Volume 1, p. 95.

[296] Excepting SO_x and CO_2 which are calculated based on the sulfur and carbon contents of the fuels.

[297] See ANL, GREET 1.6, 'Inputs' Worksheet.

These vehicles are representative of alternative vehicles offering the same approximate size and performance as the baseline vehicle. All vehicles, excepting BEVs are assumed to offer operating ranges of 300 miles or greater per fueling/charging. They are all assumed to meet or exceed Federal Tier 2, Bin 5 emissions standards. As with the baseline vehicle discussed above, energy use and emissions values for alternative vehicles are based on values published in GREET 1.6 and developed for use in the GM, ANL, et al. (2001) and (2005) WtW studies.[298] These values are presented in Table 4-3 at the end of this section.

4.2.1 Internal Combustion Engine Vehicles

This study considers several internal combustion engine vehicles (ICEVs) including spark-ignition engines fueled with reformulated gasoline (RFG), compressed natural gas (CNG), liquefied petroleum gas (LPG), and E85 (85% ethanol and 15% RFG, by volume). Additionally, this study includes compression-ignition direct-injection engines fueled with low-sulfur diesel (LSD). Each of these vehicle propulsion systems is a mature technology and all are deployed in mass-produced vehicles today. Several incremental improvements in fuel economy and performance can be expected by 2025, but by-and-large, these vehicle propulsion systems are representative of those in common use today.

The CNG, LPG and E85 vehicles are representative of either dedicated alternative fuel vehicles or the more common bi-fuel or flexible fuel vehicles which can run on either gasoline or an alternative fuel. In the case of bi-fuel or flexible fuel vehicles, the energy use and emissions profiles for CNG, LPG and E85 vehicles presented below are representative of vehicle miles traveled while fueled by an alternative fuel. Any vehicle miles traveled in

[298] See ANL, *GREET 1.6*, 'Inputs' Worksheet and GM, ANL, et al. (2001) Volume 2, Section 2 and GM, ANL, et al. (2005), Sections 2.2 and 3.

Table 4-2: Alternative Vehicle Energy Use and Emissions Values Relative to Baseline Vehicle

	SI RFG ICE HEV	SI RFG ICE PHEV (ICE Mode)	CIDI LSD ICEV	CIDI LSD ICE HEV	CID LSD ICE PHEV (ICE Mode)	SI CNG ICEV	SI LPG ICEV	SI E85 ICEV	SI E85 ICE PHEV (ICE Mode)
Energy Use	140.0%	150.0%	120.0%	160.0%	170.0%	100.0%	100.0%	100.0%	150.0%
Exhaust VOC	100.0%	100.0%		100.0%	100.0%	90.0%	100.0%	100.0%	100.0%
Evaporative VOC	71.4%	66.7%		0.0%	0.0%	5.0%	5.0%	100.0%	66.7%
CO	100.0%	100.0%		100.0%	100.0%	60.0%	60.0%	100.0%	100.0%
NO_x	100.0%	100.0%		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Exhaust PM10	100.0%	100.0%		100.0%	100.0%	20.0%	20.0%	60.0%	85.0%
Brake and Tire PM10	90.0%	90.0%		90.0%	90.0%	100.0%	100.0%	100.0%	90.0%
CH_4	100.0%	100.0%		100.0%	100.0%	500.0%	110.0%	150.0%	150.0%
N_2O	100.0%	100.0%		100.0%	100.0%	50.0%	100.0%	100.0%	100.0%

	GH2 FCV	GH2 FC PHEV (FC Mode)	LH2 FCV	LH2 FC PHEV (FC Mode)	PHEV (EV Mode)	Battery Electric Vehicle
Energy Use	235.0%	258.5%	235.0%	258.5%	525.0%	525.0%
Exhaust VOC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Evaporative VOC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CO	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NO_x	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Exhaust PM10	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brake and Tire PM10	100.0%	90.0%	100.0%	90.0%	90.0%	90.0%
CH_4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
N_2O	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

bi-fuel or flexible fuel vehicles running on gasoline are represented by the baseline SI RFG ICEV.

4.2.2 Fuel Cell Vehicles

Fuel cell vehicles are still in development stages and have yet to reach mass production. Several dozen prototype vehicles from multiple vehicle manufacturers are currently under lease to fleet owners, but many technical obstacles remain that must be solved before fuel cell vehicles can reach mass production. In Congressional testimony in March 2004, for example, a representative of the National Research Council (NRC) of the National Academies of Science and Engineering outlined three main technical challenges that must be solved before fuel cell vehicles can be commercialized:

- Current fuel cell lifetimes are far too short, greatly increasing the lifecycle costs of fuel cell vehicles;
- Fuel cell production costs are still at least an order of magnitude too high for mass production;[299]
- No onboard vehicular hydrogen storage system has been developed with an energy density necessary to provide the range expected by North American consumers (i.e. >300 miles per tank).[300]

Since the NRC testimony in 2004, automotive researchers and engineers have made headway on the onboard storage problem. For example, Honda Motor Company's second-generation FCX fuel cell prototype vehicle, unveiled in October 2005, features a new onboard gaseous hydrogen storage tank that can store 5 kg of H_2 at 5,000 psi, enabling an effective range of

[299] A significant barrier to lowering fuel cell production costs is the amount of platinum contained in low temperature fuel cells. Precious platinum-group metals are utilized as a catalyst to enable fuel cell operation at temperatures low enough for vehicle applications. Significant R&D effort is underway to reduce the platinum loading of fuel cells.

[300] See Ramage, Michael P. *The Hydrogen Economy: Opportunities, Costs, Barriers and R&D Needs.* (Presented before the U.S. House of Representatives, Committee on Science, March 3, 2004). p. ES-3.

350 miles.[301] Honda plans to begin limited production of the second-generation FCX by the end of this decade.[302]

Despite recent progress, cost remains by far the largest barrier to the introduction of fuel cell vehicles. Current commercialized fuel cell costs range between $300 and $3000/kilowatt (kW)[303] while the NRC reports that hydrogen fuel cell costs must decrease to less than $100/kW before it becomes plausible to commercialize FCVs.[304] In particular, the NRC reports, "if the cost of the fuel cell system for light-duty vehicles does not eventually decrease to the $50/kW range, fuel cells will not propel the hydrogen economy without some regulatory mandate or incentive."[305] This scale of reduction is not likely to occur until the middle of the next decade at the earliest, the NRC concludes.[306]

Still, R&D efforts are underway at major automotive companies and government research centers and fuel cell vehicles may be commercialized within the timeframe of this study. By 2025, FCVs could begin to acquire a small but growing market share amongst light-duty vehicles. As such, FCVs are included in this study. The most likely fuel cell candidate for use in vehicle applications is the Proton Exchange Membrane or PEM fuel cell.[307] PEM fuel cells operate at low temperatures (around 80° C) and have high power densities and low weight and volume relative to other types of fuel cells.[308] These qualities make PEM fuel cells the frontrunner for use in FCVs. This study considers PEM fuel cell

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[301] See Honda Motor Company. "Honda to Begin Producing Next Generation FCX Hydrogen Fuel Cell Vehicle". *News Release 2006*. Jan. 8, 2006. <http://world.honda.com/news/2006/4060108FCX/>. Accessed 5/18/2006. The storage tank makes use of an unspecified "newly developed hydrogen absorption material in the tank doubles capacity" at 5,000 psi.
[302] ibid.
[303] Mazza and Hammerschlag (2004), p. 27.
[304] Ramage (2004), p. ES-7.
[305] ibid. p. ES-7.
[306] ibid. p. ES-7.
[307] PEM fuel cells are also referred to as Polymer Exchange Membrane fuel cells.
[308] EERE (2006).

vehicles utilizing both compressed gaseous hydrogen stored onboard at 5,000 psi as well as liquid hydrogen stored onboard in cryogenic containers. Both storage options are being considered to provide adequate onboard storage and vehicle operating range.[309]

4.2.3 Electric and Hybrid Electric Vehicles

Hybrid Electric Vehicles:

Since the introduction of the Honda Insight in North America in 1999, hybrid electric vehicles have been successfully commercialized by a number of major auto manufacturers and have achieved a small but growing segment of the light-duty vehicle market. Honda, Toyota, Ford and General Motors all currently have HEVs on the market and more are due out in coming years including HEV offerings from Hyundai, Nissan and DaimlerChrysler.[310] Hybrid electric vehicles combine traditional internal combustion engines with an electric motor and limited battery energy storage. The batteries allow the vehicle to convert kinetic energy normally wasted during braking into electrical energy to charge the hybrid's batteries, a process known as 'regenerative braking.' Additionally, the addition of an electric motor usually allows HEVs to switch off the ICE when the engine is at idle (i.e., at stop lights or in stop and go traffic, etc.) with the electric motor providing initial launch power away from a stop. This is known as 'stop-start idle reduction capability' and boosts the vehicle's fuel economy by reducing wasted fuel consumed during engine idling. The addition of an electric motor, which is more efficient than an ICE, and the ability to recover wasted energy using

[309] Two other potential options for onboard storage are metal hydrides and chemical slurries. These options are much farther from commercialization than compressed gas or cryogenic liquid storage but could ultimately hold more promise.
[310] For a complete list of currently available and expected future HEV models, see <http://www.hybridcars.com/cars.html>.

regenerative braking and employ stop-start idle reduction boosts the fuel economy of HEVs 10-50% above similarly sized conventional ICEVs, depending on the degree of hybridization and actual driving patterns.[311] Hybrid electric vehicles do not need to be plugged in to charge, as the vehicle's batteries are charged through regenerative braking, or by the vehicle's primary engine.[312] Thus, HEVs are also referred to as 'grid-independent' hybrid electric vehicles, to distinguish them from the 'grid-connected', or plug-in hybrid electric vehicles discussed below.

This study includes SI and CIDI hybrid electric vehicles fueled with RFG and LSD as these are the most mature fuel and vehicle platforms and are the most likely to see commercialized hybrid electric versions. Hybrid electric versions of SI vehicles fueled with other fuels, particularly E85 vehicles, are possible, but current market focus is on hybrid versions of gasoline and diesel-fueled vehicles. This study assumes that HEVs boost fuel economy 40% relative to the equivalent non-hybrid SI ICE vehicle and 33% relative to non-hybrid CIDI vehicles.[313] This is meant to represent a strong parallel hybrid electric vehicle capable of propelling the vehicle from a stop. The electric motor is sized to meet the performance standards for all vehicles in this study (see Section 2.2) and battery storage was sized to provide a 7.5-mile all-electric range. It is assumed that HEVs employ nickel-metal

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[311] For example, GM's 'mild' hybrid system found in their GMC Sierra and Chevy Silverado full-size pickups only achieves a 10% improvement in fuel economy. In contrast, the Ford Escape hybrid SUV gets over 50% better gas mileage (30 mpg) than its non-hybrid version (19 mpg). The hybrid version of the Toyota Camry, released this year, gets 40 mpg, a 42% increase over a non-hybrid Camry. See <http://www.fueleconomy.gov/>. Real-world fuel economy improvements depend considerably on the actual driving patterns with hybrids providing particularly good fuel economy during stop-and-go city driving (when regenerative braking and stop-start idle reduction are most effective and low speeds enable the use of the electric motor). Hybrids generally provide little fuel economy improvement at highway driving speeds.

[312] Charging of the batteries with the primary engine is only possible in series and series-parallel hybrid configurations.

[313] CIDI engines are more efficient than SI engines so the fuel economy benefits of introducing an electric motor are slightly less pronounced.

hydride (NiMH) batteries found in all current commercially available HEVs.[314] As summarized in Table 2-2 above, HEVs are assumed to deliver the same exhaust emissions as non-hybrid propulsion systems of the same time, excepting for SO_x and CO_2. Higher fuel economy generally corresponds to decreased emissions. However, in HEVs, the emissions improvements due to increased fuel economy are offset by the frequent engine starts that result from utilizing start-stop idle reduction. Engines combustion during startup is generally less complete and results in higher emissions than when the engine is warm.[315] Combustion emissions of SO_x and CO_2 are based on the sulfur and carbon contents of the fuels and are assumed to scale with fuel economy, as are evaporative emissions of VOCs. PM10 emissions from tire and brake wear are assumed to be 10% lower than an equivalent non-hybrid propulsion system to represent reduced brake wear due to the use of regenerative braking.

Plug-in Hybrid Electric Vehicles:

Grid-connected, or plug-in hybrid electric vehicles (PHEVs) are hybrid electric vehicles with enlarged battery storage capacities and the ability to charge the batteries with electricity from the grid. This enables an extended all-electric driving range, generally between 20 to 60 miles. When this all-electric range is exhausted, PHEVs operate like HEVs and boost the fuel economy of the primary engine by 40-50%.

PHEVs are still in pre-commercialization stages. However, they share much of their architecture with grid-independent HEVs and the rapid commercialization of HEVs has sped the development of PHEVs. DaimlerChrysler has been working with the Electric Power

[314] See GM, ANL, et al. (2005), p. 59-60 for a discussion of the hybrid vehicle propulsion system modeled in GREET and used in this study.

[315] See ibid. p. 63.

Research Institute (EPRI) to develop a PHEV version of their Sprinter medium-duty van. Several configurations of the Sprinter PHEV are currently undergoing fleet feasibility testing in a number of North American and European locations.[316] PHEVs could easily be commercialized within the time frame considered in this study, perhaps as early as the beginning of the next decade.

The major barriers to the commercialization of PHEVs are the cost and lifespan of advanced batteries suitable for use in PHEVs. The commercialization of HEVs has driven down the cost of many shared components including high power electric drive motors, charge controllers, inverters and other electrical hardware, reducing the prospective cost for PHEVs as well. However, batteries for use in PHEVs differ from those in HEVs. While HEV batteries have small energy storage capacities and are optimized to deliver power to assist the primary engine (i.e., 'power' batteries), PHEV batteries must be optimized for long range (i.e. high energy storage or 'energy' batteries) and operation over a wider range of driving conditions.[317] In this manner, PHEV batteries are similar to those designed for use in all-electric or battery electric vehicles (BEVs, see below). 'Energy' batteries suitable for use in PHEVs (and BEVs) remain costly at this time, partly due to the absence of economies of scale now present for 'power' batteries used in HEVs. However, a 2004 EPRI study on the cost-effectiveness and technical feasibility of advanced batteries for vehicle applications concluded that at modest production volumes of 48,000 to 150,000 batteries per year, 'energy' batteries for use in PHEVs could be produced at a cost low enough to allow PHEVs to achieve 'lifecycle cost parity' – i.e. equal purchase, operation and maintenance costs over

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[316] See Sanna, Lucy. "Driving the Solution: the Plug-in Hybrid Vehicle". *EPRI Journal* (Fall 2005): 8-17.
[317] Electric Power Research Institute. *Advanced Batteries for Electric-Drive Vehicle: A Technology and Cost-Effectiveness Assessment for Battery Electric Vehicle, Power Assist Hybrid Electric Vehicles, and Plug-In Hybrid Electric Vehicles*. (Palo Alto, CA: Electric Power Research Institute, May 2004). pps. viii and ix.

the lifetime of the vehicle – with conventional and hybrid electric vehicles.[318] The EPRI study found that this cost parity could be achieved by the end of the decade and could pave the way for commercialization of PHEVs.[319]

Another potential barrier to the introduction of PHEVs is the lifetime of the batteries. Batteries for PHEVs must last as long as the useful life of the vehicle (10-15 years and approx. 150,000 miles). Otherwise, a costly battery replacement will be required, greatly increasing the lifecycle cost of the vehicle. Fortunately, the EPRI study reports that currently available NiMH 'energy' batteries "appear to exceed projected cycle life and durability expectations" for PHEVs and can deliver lifetime mileages between 130,000-150,000 miles (with 33,000-100,000 miles driven in electric-mode depending on the size of the batteries and all-electric range of the PHEV).[320] Additionally, the EPRI study reports that lithium ion (Li ion) batteries are available now that meet all PHEV performance requirements. Li ion batteries have higher energy densities (the ratio of energy storage capacity to battery weight) and better efficiencies than NiMH batteries. However, adequate cycle life and durability for use in PHEVs has yet to be proven with Li ion batteries. The EPRI study reports, "If the required cycle life and, equally important, adequate calendar life can be achieved in testing or through continued development, lithium ion batteries will become an excellent technical

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[318] ibid. p. ix. The potential to achieve cost cost parity is partly enabled by the reduced cost of electric components driven by the commercialization of HEVs. Lower costs for these electric components raises the cost target necessary for PHEVs to achieve cost parity with conventional vehicles from $150 per kWh (storage capacity), as estimated in the early 1990s, to $380-$471 per kWh, according to the EPRI study. See p. ix.

[319] ibid. p. ix.

[320] See ibid. p. vii. Cycle life – i.e. how many times a battery can be fully discharged before significant degradation occurs – is the crucial determining factor for battery lifetimes. Thus, PHEVs with larger batteries and longer all-electric ranges (40-60 mi) will experience less 'depth-of-discharge' (the percent of maximum energy capacity discharged before recharging) over a given mileage driven and thus have longer battery lifetimes. Batteries with smaller storage capacities for use in HEVs or PHEVs with a 20-mile range will experience more frequent and deeper discharges and more full cycles within the same amount of mileage driven and thus experience shorter battery lifetimes.

choice for PHEV applications."[321] Thus, it appears that energy batteries can be commercialized in the near future that will deliver adequate performance and long cycle lifetimes capable of meeting the lifetime mileage requirements of a PHEV on a single battery pack.

NiMH batteries will likely be the first to be commercialized for use in PHEVs (as they were for use in HEVs). However, assuming adequate cycle life and durability can be demonstrated and economies of scale can be developed, a prospect EPRI considers feasible within the next 3-5 years,[322] Li ion batteries will likely erode NiMH market share within the time frame considered in this study due to their superior characteristics.[323] In addition to excellent energy densities, Li ion batteries have very high coulombic efficiencies – the ratio of the energy that can be recovered from the battery for use to the amount of energy used to charge the battery – of nearly 100%.[324] In contrast, the coulombic efficiency of NiMH batteries is typically only about 66% and decreases the quicker the charge time.[325] Thus, a third or more of all energy used to charge a NiMH battery is lost, while nearly 100% of the energy used to charge a Li ion battery can be recovered and put to use. This characteristic alone makes a PHEV using Li ion batteries 50% more efficient while in all-electric mode than a comparable PHEV using NiMH batteries. Thus, there are significant performance incentives encouraging the utilization of Li ion batteries in PHEVs and EVs.

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[321] ibid. p. 2-2.
[322] ibid. p. 2-2.
[323] While Li-ion batteries are currently more expensive than NiMH batteries, at mass production economies of scale, projected costs of Li-ion batteries are equal to or lower than those for comparable NiMH batteries at the same production scale. EPRI finds that, "the prospects for mass-produced Li ion batteries to meet the cost requirements for PHEV applications also can be considered encouraging." See ibid. p. 2-8.
[324] See Axeon Power, Ltd. "Rechargeable Lithium Batteries". *Custom Power Solutions*. <http://www.axeonpower.com/lithiumS.htm>. Accessed 5/19/2006.
[325] See Axeon Power, Ltd. "Nickel Metal Hydride Batteries". *Custom Power Solutions*. <http://www.axeonpower.com/nimh.htm>. Accessed 5/19/2006. Clearly there is a strong incentive to achieve as a charge time as possible in electric vehicle applications, further degrading the coulombic efficiency of NiMH batteries.

This study considers plug-in hybrid versions of many of the other vehicle propulsion systems, including PHEV versions of the SI RFG, CIDI LSD, SI E85 and GH2 and LH2 FC propulsion systems. All of these PHEV systems are assumed to use Li ion batteries[326] with energy storage capacities sufficient to provide a 20-mile all electric driving range. This should allow around 36% of the vehicle miles traveled by PHEVs to be driven in all-electric mode, while remainder is assumed to be in hybrid-electric ICE or FC mode.[327] As shown in Table 2-2 above, PHEVs are assumed to deliver fuel economy 525% of the baseline SI RFG ICEV while operating in electric mode.[328] While in hybrid-electric ICE or FC mode, PHEVs are assumed to deliver fuel economy improvements of 50.0% over comparable SI ICEVs, 41.7% over CIDI ICEVs and only 10% over FCVs.[329] While in electric mode, PHEVs result in zero combustion and evaporative emissions. As with HEVs (see above) while in hybrid-electric ICE or FC mode, emissions for PHEVs are assumed to be the same as the non-hybrid, excepting SO_x, CO_2 and VOC emissions which scale with fuel economy and PM10 emissions from tire and brake wear which are assumed to be 10% lower representing reduced brake wear from regenerative braking. Vehicle miles traveled in all-electric mode are

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[326] Note: this assumption differs from that of GREET 1.6 and the GM, ANL, et al. (2001) and (2005) WtW studies who assume PHEVs and EVs use NiMH batteries. See GM, ANL, et al. (2005), p. 60.

[327] EPRI (2004) reports that PHEVs with a 20-mile all-electric range can drive between 22% and 50% of their vehicle miles traveled (VMT) in all-electric mode. The median is thus 36% which is the value selected by this study. This is conservative as PHEVs with larger all-electric ranges of 40-60 miles can drive 33-65% of their VMT in EV mode. See p. 1-3.

[328] GREET 1.6 assumes that EVs and PHEVs in all-electric mode using NiMH batteries achieve fuel economy 350% of the baseline SI RFG ICEV, or 77 gasoline-equivalent mpg. Assuming Li ion batteries offer a 150% improvement over NiMH batteries due to increased coulombic efficiency (99% compared to 66% or lower), a PHEV using Li ion batteries should achieve 115.5 gasoline-equivalent mpg, or 525% of the baseline vehicle's 22 mpg. This is equivalent to an energy consumption of .293 kWh per mile. This may actually be conservative as EPRI (2004) assumes an energy consumption of .285 kWh per mile for a PHEV with a 20-mile EV range representing currently available (i.e. NiMH) batteries. See p. 4-14.

[329] Hybridization of fuel cell vehicles offers relatively little fuel economy improvement as FCVs already utilize efficient electric motors and have start-stop idle reduction capabilities. Thus, the 10% improvement from hybridization of FCVs is representative of the ability to employ regenerative braking absent in non-hybrid FCVs. Despite the moderate improvements, hybridization of FCVs is technically easy to achieve given that FCVs already have the requisite electric components.

assumed to be fueled with electricity from either the US Average Mix or High Renewables Mix (see 3.42. above).

Battery Electric Vehicles:

Battery electric vehicles are all-electric vehicles with large battery energy storage capacity and are charged with electricity from the grid. They offer high fuel economy and zero vehicle operating emissions, excepting for PM10 emissions due to tire and brake wear. As with HEVs and PHEVs, tire and brake wear PM10 emissions are assumed to be 10% lower than the baseline vehicle due to the use of regenerative braking. Unlike all of the other vehicles considered in this study, BEVs do not offer operating ranges of 300 miles or greater. BEV operating ranges are constrained by adequate battery storage capacity, one of the main hurdles to the widespread introduction of EVs. However, recent progress in advanced battery technology has yielded cell chemistries with high energy densities enabling extended BEV operating ranges. For example, the Maya-100 EV, an all-electric compact SUV developed by the Canadian lithium-polymer battery manufacturer, Electrovaya, has an operating range of over 180 miles (300 km).[330]

As with PHEVs, battery cost and lifespan remain barriers to the introduction of BEVs, and these problems are more pronounced for BEVs than PHEVs due to the larger batteries required. However, as with PHEVs, the costs for electrical components shared between BEVs and HEVs have been driven down in recent years by volume-scale production of these components for use in commercially available HEVs. Similarly, the future commercialization of PHEVs could pave the way for the later mass production of BEVs as

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[330] DasGupta, S. et al. *A Long Range, Ultra-Safe, Low Cost Electric Vehicle*. (Presented at EVS21, Monaco, April 2005, Electrovaya). p. 2.

the two share similar batteries. For example, the EPRI (2004) study examines the lifecycle costs for a city electric vehicle with a 40-mile range. Such a vehicle could utilize the same batteries as a PHEV with a 20-mile all electric range and could thus enjoy the production economies of scale achieved for PHEVs. The EPRI study concludes that such a city EV would achieve lifecycle cost-parity with conventional vehicles assuming a production volume of 100,000 PHEV or BEV batteries per yeab.[331] Also, as with batteries for PHEVs, available NiMH batteries can provide operating lifetimes greater between 130,000-150,000 miles or more and Li ion batteries could be developed and tested in the next few years that offer a similar lifetime.[332]

A number of small ‘city electric vehicles’ with operating ranges less than 50 miles and low top speeds (<55 mph) are currently available and are produced in small numbers by several small manufacturers. Both GM and Toyota leased and sold limited numbers of full-sized electric vehicles (i.e., GM’s EV1 and Toyota’s RAV4 EV) with extended operating ranges[333] during the late 1990s and early 2000s but have since discontinued their EV programs. Within the timeframe considered in this study, full-size BEVs with extended driving ranges could be commercialized, especially in conjunction with the commercialization of PHEVs (as discussed above).[334] This study thus includes BEVs using lithium ion batteries representative of full-size electric vehicles capable of highway driving

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[331] See EPRI (2004), p. viii.
[332] ibid. pps. vii-viii.
[333] 75-130 mi per charge for the second generation EV1 and 80-120 mi for the RAV4 EV, both with NiMH batteries.
[334] Mitsubishi Motors, for example, may release a mass market BEV by the end of the decade based on their Concept-CT MIEV, a compact concept electric vehicle unveiled in February 2006. The Concept-CT uses Li ion batteries and has an operating range of 75 mi (120 km) per charge. Mitsubishi Motor Company. “Mitsubishi Motors lineup at 76th Geneva Motor Show”. *Motor Show*. Feb. 28, 2006. <http://media.mitsubishi-motors.com/pressrelease/e/motorshow/detail1424.html>. Accessed 5/19/2006.

speeds with operating ranges greater than 100 miles. Like PHEVs in all-electric mode, these BEVs are assumed to achieve fuel economy 525% of the baseline vehicle.

4.3 Vehicle Operation

Table 4-3 below summarizes the PtW energy use and emissions associated with vehicle operation and fueling. Assumptions related to these PtW values can be found in Sections 4.1 and 4.2 above. This study assumes that 62.2% of all vehicle operation emissions are urban emissions (i.e., they occur within populated urban areas), based on the assumptions published in GREET 1.7b.[335] This assumption is meant to represent the share of vehicle miles traveled by light-duty vehicles within populated areas.

[335] See ANL, *GREET 1.7 Beta*, 'Urban_Shares' worksheet. Reportedly based on Federal Highway Administration data.

Table 4-3: Alternative Vehicle Pump-to-Wheels Energy Use and Emissions Values

	SI RFG ICEV (Baseline)	***SI RFG ICE HEV***	***SI RFG ICE PHEV (ICE Mode)***	***CIDI LSD ICEV***	***CIDI LSD ICE HEV***	***CID LSD ICE PHEV (ICE Mode)***	***SI CNG ICEV***	***SI LPG ICEV***
Gasoline equiv. mpg*	22.0	30.8	33.0	26.4	35.2	37.4	22.0	22.0
Energy Use (Btu/mi)	5,153	3,681	3,436	4,295	3,221	3,031	5,153	5,153
Emissions (g/mi)								
Exhaust VOC	0.077	0.077	0.077	0.061	0.061	0.061	0.069	0.077
Evaporative VOC	0.078	0.056	0.052	0.000	0.000	0.000	0.004	0.004
CO	3.436	3.436	3.436	3.438	3.438	3.438	2.062	2.062
NO_x	0.045	0.045	0.045	0.070	0.070	0.070	0.045	0.045
Exhaust PM10	0.010	0.010	0.010	0.010	0.010	0.010	0.002	0.002
Brake & Tire PM10	0.021	0.019	0.019	0.021	0.019	0.019	0.021	0.021
SO_x	0.006	0.005	0.004	0.003	0.002	0.002	0.002	0.000
CH_4	0.081	0.081	0.081	0.014	0.014	0.014	0.405	0.089
N_2O	0.035	0.035	0.035	0.020	0.020	0.020	0.018	0.035
CO_2	368	263	245	347	260	245	308	369

* Energy content of one gallon of reformulated gasoline: 113,377 Btu.

Table 4-3: Alternative Vehicle Pump-to-Wheels Energy Use and Emissions Values (*Continued*)

	SI E85 ICEV	***SI E85 ICE PHEV (ICE Mode)***	***GH2 FCV***	***GH2 FC PHEV (FC Mode)***	***LH2 FCV***	***LH2 FC PHEV (FC Mode)***	***PHEV (BEV Mode)***	***Battery Electric Vehicle***
Gasoline equiv. mpg*	22.0	33.0	51.7	56.9	51.7	56.9	115.5	115.5
Energy Use (Btu/mi)	5,153	3,436	2,193	1,994	2,193	1,994	982	982
Emissions (g/mi)								
Exhaust VOC	0.077	0.077	0.000	0.000	0.000	0.000	0.000	0.000
Evaporative VOC	0.078	0.052	0.000	0.000	0.000	0.000	0.000	0.000
CO	3.436	3.436	0.000	0.000	0.000	0.000	0.000	0.000
NO_x	0.045	0.045	0.000	0.000	0.000	0.000	0.000	0.000
Exhaust PM10	0.006	0.006	0.000	0.000	0.000	0.000	0.000	0.000
Brake & Tire PM10	0.021	0.019	0.021	0.019	0.021	0.019	0.019	0.019
SO_x	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000
CH_4	0.122	0.122	0.000	0.000	0.000	0.000	0.000	0.000
N_2O	0.035	0.035	0.000	0.000	0.000	0.000	0.000	0.000
CO_2	81^	54^	0	0	0	0	0	0

* Energy content of one gallon of reformulated gasoline: 113,377 Btu.
^Actual combustion emissions are 389 g/mi for SI E85 ICEC and 259 g/mi for SI E85 PHEV but credits of 308 g/mi and 205 g/mi are applied, respectively, to represent the amount of CO_2 contained in burnt ethanol that was originally from the atmosphere.

5. WELL-TO-WHEEL RESULTS

Section 3 above described the WtP fuel production pathways and related assumptions. Results were presented as energy use and emissions per mmBtu of fuel delivered to vehicle fueling stations. Section 4 presented the vehicle propulsion systems considered in this study and described assumptions related to the PtW vehicle fueling and operation stage. Results were presented as energy use and emissions per mile driven. This section combines the 15 PtW vehicle propulsion systems (see Table 4-1) with several pathways selected from amongst the 70 WtP fuel production pathways considered in this study (see Table 3-1) to present energy use and emissions results for full well-to-wheel (WtW) fuel production/vehicle system pathways.[336] This study presents WtW results for 17 metrics, as summarized in Table 5-1.

Table 5-1: Energy Use and Emissions Metrics Analyzed by this Study

Energy Use	***Greenhouse Gas Emissions***	***Total Pollutant Emissions***	***Urban Pollutant Emissions***
Total Energy	CO_2	Total VOC	Urban VOC
Fossil Energy (subset of Total Energy)	CH_4	Total CO	Urban CO
	N_2O	Total NO_x	Urban NO_x
Petroleum Energy (subset of Fossil Energy)	Total Global Warming Potential-weighted GHGs	Total PM10	Urban PM10
		Total SO_x	Urban SO_x

Of the 60 full WtW pathways considered by this study, the following sub-sections present 31 selected pathways and their WtW energy use and emissions results.[337] These pathways are intended to be representative of the various alternative fuel and vehicle propulsion systems considered and should allow direct comparisons to be drawn between the

[336] WtW results are generated by combining the PtW vehicle operation and fueling energy use and emissions with the upstream WtP energy use and emissions associated with producing and delivering enough fuel to drive the vehicle one mile.
[337] A complete table of WtW results for all 60 pathways can be found in Appendix A.

energy use and emissions effects resulting from the use of various alternative fuels and vehicle propulsion systems. The following sub-sections present WtW results for each of the 17 metrics used by this study (see Table 5-1 above) and use these metrics to objectively compare the relative benefits or drawbacks of the 31 WtW pathways considered. Section 5.1 presents WtW energy use results while Section 5.2 presents results for greenhouse gas (GHG) emissions. WtW results for criteria pollutant emissions are presented in Section 5.3.

Of the 31 pathways, six are petroleum-based pathways ending with internal combustion engine vehicles (ICEVs) (including two grid-independent hybrid-electric vehicles [HEVs] and two grid-connected plug-in hybrid-electric vehicles [PHEVs]), six are natural-gas-based pathways (including SI CNG and LPG vehicles and hydrogen fuel cell vehicles), ten are biomass-based pathways representing vehicles fueled with ethanol (E85) (including five E85 PHEVs), and nine are electricity-based pathways including battery electric vehicles and hydrogen vehicles fueled with hydrogen from electrolysis (electrolytic hydrogen). The 31 pathways are summarized in Table 5-2 below. Finally, in addition to the figures and discussion presented in the following pages, relative changes in WtW energy use and emissions for the 31 selected pathways (compared to the baseline pathway) are presented in tabular form in Section 5.4.

Table 5-2: 31 Selected Well-to-Wheels Pathways

WtP Fuel Production Pathway	***PtW Vehicle Propulsion System***
Petroleum-based Pathways	
Reformulated Gasoline (RFG)	Spark-ignition (SI) RFG ICEV
	SI RFG ICE HEV
and Electricity from US Average Mix	SI RFG ICE PHEV
Low-sulfur Diesel (LSD)	Compression-ignition direct-injection (CIDI) LSD ICEV
	CIDI LSD ICE HEV
and Electricity from US Average Mix	CIDI LSD ICE PHEV

Table 5-2: 31 Selected Well-to-Wheels Pathways

WtP Fuel Production Pathway	PtW Vehicle Propulsion System
Natural Gas-based Pathways	
Liquefied Petroleum Gas (LPG)	SI LPG ICEV
Compressed Natural Gas (CNG) from Non-North American (N-NA) Natural Gas (NG)	SI CNG ICEV
Gaseous hydrogen (GH2) via central SMR with N-NA NG	GH2 FCV
and electricity from US Ave Mix	GH2 FC PHEV
LH2 via central SMR with N-NA NG	LH2 FCV
and electricity from US Ave Mix	LH2 FC PHEV
Biomass-based Pathways	
E85 from Corn EtOH and RFG	SI E85 ICEV
and Electricity from US Ave Mix	SI E85 ICE PHEV
E85 from Herbaceous Cellulosic EtOH (Switchgrass) and RFG	SI E85 ICEV
and Electricity from UC Ave Mix	SI E85 ICE PHEV
E85 from Herbaceous Cellulosic EtOH (Waste) and RFG	SI E85 ICEV
and Electricity from US Ave Mix	SI E85 ICE PHEV
E85 from Woody Cellulosic EtOH (Hybrid Poplar) and RFG	SI E85 ICEV
and Electricity from US Ave Mix	SI E85 ICE PHEV
E85 from Woody Cellulosic EtOH (Waste) and RFG	SI E85 ICEV
and Electricity from US Ave Mix	SI E85 ICE PHEV
Electricity-based Pathways	
Electricity from US Ave Mix	BEV
Gaseous hydrogen (GH2) via station electrolysis with US Ave Mix electricity	GH2 FCV
and electricity from US Ave Mix	GH2 FC PHEV
Liquid hydrogen (LH2) via station electrolysis with US Ave Mix electricity	LH2 FCV
and electricity from US Ave Mix	LH2 FC PHEV

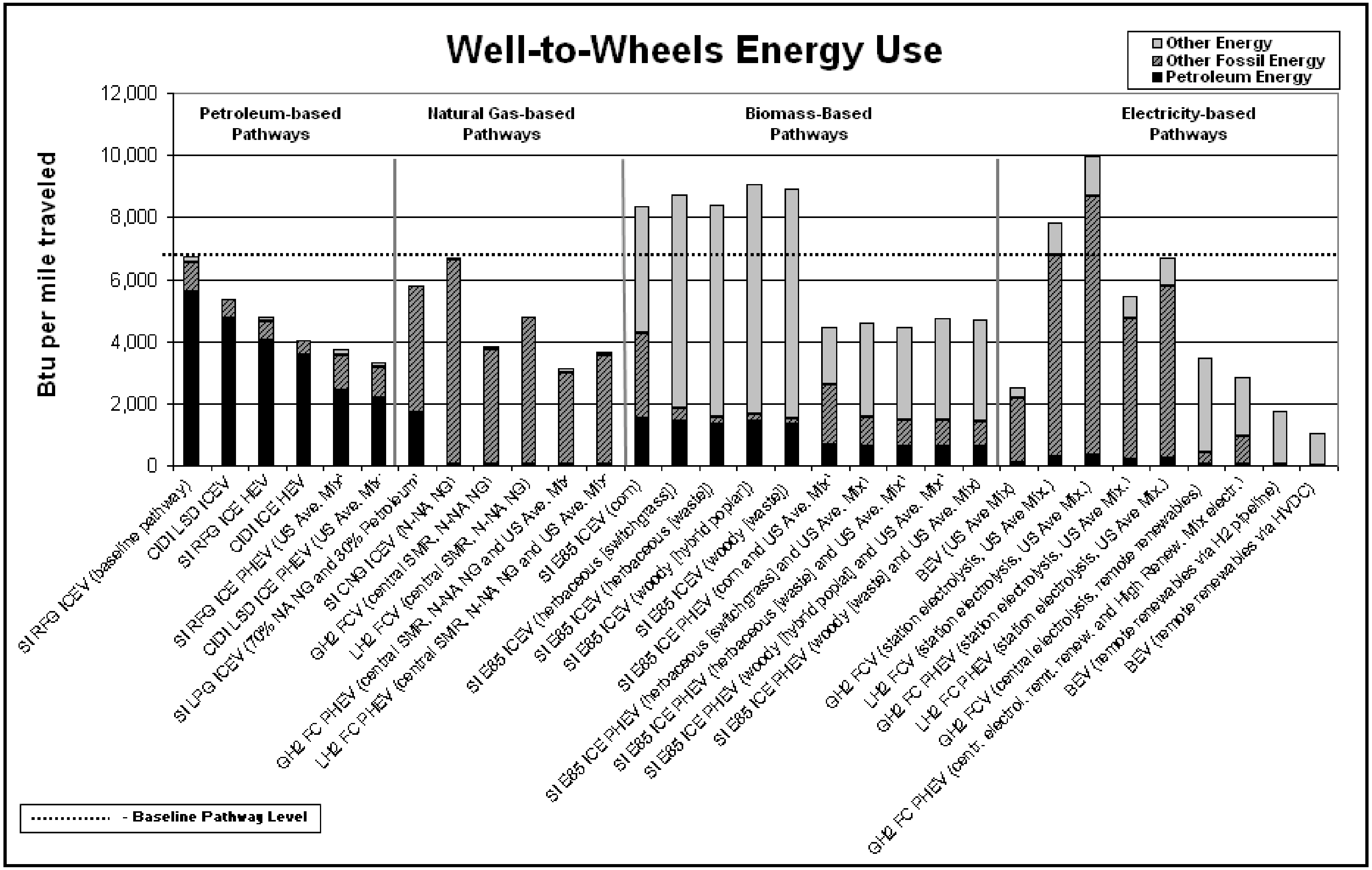
5.1 Well-to-Wheels Energy Use

Figure 5-1 below summarizes WtW energy use results for the 31 selected WtW pathways. All five of the alternative petroleum-fueled pathways result in reductions in total, petroleum and fossil energy use relative to the baseline SI RFG ICEV pathway. Total, petroleum and fossil energy reductions for the CIDI LSD pathway and the two petroleum-fueled HEVs are the result of increased fuel economy (see Section 4.2), although the higher refining efficiency of LSD relative to RFG (see Section 3.1.2) also reduces the energy use of LSD-fueled pathways. The two petroleum-fueled PHEV pathways see additional reductions in total energy use due to the fact that approximately one-third (36%) of vehicle miles traveled (VMT) for these pathways are traveled in the PHEV's very efficient all-electric mode (with fuel economy 525% of the baseline vehicle). Due to the predominance of fossil-fired power plants in the US average electricity mix (mostly coal-fired plants, see Section 3.4.2), the share of fossil energy increases for the PHEV pathways. However, petroleum energy use for PHEVs continues to decrease as petroleum-fired power plants make up a very small portion of the US average electricity mix (i.e., only 1.9%, see Table 3-13).

The LPG pathway offers a slight reduction in total and fossil energy use relative to the baseline pathway (although not as large as those achieved by any of the alternative petroleum-fueled pathways), while the CNG pathway has total and fossil energy use comparable to the baseline. However, the CNG and LPG-fueled pathways do offer significant reductions in petroleum-energy use due to the substitution of natural gas for petroleum as the base feedstock for these pathways. The CNG-based pathway thus virtually eliminates petroleum energy use (with the small remainder due to transportation of the feedstock and fuel). The LPG pathway also offers a significant petroleum energy reduction, but this reduction is less than that for CNG as 30% of the feedstock for LPG production is provided by petroleum (see section 3.2.2). Like the CNG pathway, the GH2 and LH2 FCVs fueled with hydrogen derived from natural gas virtually eliminate petroleum energy use as they rely on natural gas for their base feedstock.

Additionally, all of the hydrogen-from-natural gas pathways result in total and fossil

Figure 5-1: Well-to-Wheels Energy Use



energy use approx. 25-50% lower than the baseline pathway. In addition to providing small decreases in total energy use (due to increased PtW efficiency), the FC PHEV pathways also substitute energy derived from coal and, to a small degree, renewables for a portion of the natural gas-derived energy (i.e., the coal and renewables-derived electricity in the U.S. Ave. Mix, see Table 3-13). This could be an important benefit as coal and renewables are not subject to the same resource depletion concerns as natural gas.[338] Note that all liquid hydrogen pathways have around 25% higher energy inputs than equivalent gaseous hydrogen pathways due to the increased energy losses associated with liquification and storage of LH2 relative to the compression and storage of GH2 (see Section 3.2.2).

Total energy use for each of the non-PHEV ethanol-fueled pathways is approximately 25-33% higher than for the baseline pathway. However, the bulk of the total energy for these pathways is provided by the biomass feedstock (either corn or woody or herbaceous biomass) and is thus both renewable and domestically produced. These pathways offer significant reductions in both fossil and petroleum energy use relative to the baseline pathway. The corn ethanol pathway results in an approximately 35% reduction in fossil energy use and a 75% reduction in petroleum energy use. The most significant fossil energy inputs in the corn ethanol pathway are in the form of coal and natural gas burned for process energy during ethanol production from corn (see Section 3.3.4), while the production and application of agricultural chemicals (see Sections 3.3.1 and 3.3.2) and, to a lesser degree, the transportation of feedstocks and fuels both contribute to fossil energy use for this pathway. The cellulosic ethanol (from woody and herbaceous biomass) pathways see decreased fossil

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[338] This points to the potentially confusing nature of the fossil energy metric as it does not differentiate coal and natural gas-derived energy. As coal and natural gas are subject to vastly different resource depletion concerns and result in considerably different emissions, a detailed analysis may wish to further separate coal and natural gas-derived energy into distinct metrics. However, as GREET currently does not separate these two fossil energy sources, such an analysis was beyond the scope of this study.

energy use relative to the corn ethanol pathway, largely due to the fact that lignin from the biomass feedstock, rather than coal or natural gas, provides the process energy needed for cellulosic ethanol production (as well as a significant amount of electricity for export, see Section 3.3.4). The remaining fossil energy inputs for the cellulosic ethanol pathways represent the production and application of agricultural chemicals during biomass farming. The cellulosic ethanol pathways all see an approx. 70-75% reduction in fossil energy use and a 75% reduction in petroleum energy use. The bulk of the remaining petroleum energy in all of the ethanol pathways is due to the fact that RFG makes up 15% of E85, by volume (although a small amount is due to the transportation of feedstocks and fuels).

The ethanol-fueled PHEV pathways see significant reductions in total, fossil and petroleum energy use, with total energy use approx. 33% less than for the baseline. This is again due to the fact that approx. one-third of all VMT in these PHEVs are traveled in the very efficient all-electric mode, substituting electricity from the US average mix for E85 as fuel. The remaining VMT also benefit from hybridization (see Section 4.2.3) and the resulting increase in fuel economy further reduces energy use for these pathways. As with petroleum-fueled PHEVs, the large share of coal and natural gas-fired power plants in the US average electricity mix results in an increase in the share of non-petroleum fossil energy for the ethanol-fueled PHEV pathways. Each of these pathways uses very little petroleum energy, however, resulting in approx. 90% reductions relative to the baseline vehicle for each ethanol-fueled PHEV pathway. Fossil energy use for the corn ethanol-fueled PHEV pathway is approx. 60% less than the baseline vehicle while the other ethanol-fueled PHEV pathways result in approx. 75-78% reductions in fossil energy use.

Figure 5-1 illustrates the large difference in WtW energy use between electricity-based BEV and hydrogen FCV pathways due to the differences in WtW efficiencies for these pathways. The pathway representing a BEV fueled with electricity from the U.S. average electricity mix reduces total and fossil energy use by approx. two-thirds relative to the baseline. This is due to the high PtW efficiency of electric vehicle pathways, which is sufficient to overcome even the low WtP efficiency of the electricity production pathways (see Table 3-16). As would be expected, fossil, petroleum and other energy inputs for BEVs powered by electricity from the U.S. average mix are proportionate to the share of fossil, petroleum, and nuclear and renewable-derived electricity in the electricity mix (see Table 3-13). Thus, this pathway nearly eliminates petroleum energy use as petroleum-fired power plants make up a tiny share of the U.S. generation mix.

In contrast to the large reduction offered by BEVs fueled with electricity from the grid, the electrolysis-based hydrogen-fueled pathways actually result in increases in both total and fossil energy relative to the baseline pathway. This is due to the large energy losses associated with the production of hydrogen via electrolysis and conversion back to electricity in fuel cells (see Sections 3.4.3 and 3.4.4). As with the BEV pathway above, the shares of fossil, petroleum and other energy (i.e., renewable) inputs in the electrolytic hydrogen pathways are proportional to shares of electricity derived from fossil, petroleum, and nuclear and renewable sources in the US average mix (see Table 3-13). Thus, in terms of energy use, the electrolytic hydrogen pathways offer, at best, the substitution of coal and natural gas-derived electrical energy (as well as additional quantities of electricity from renewables) for the predominately petroleum-derived energy use associated with baseline pathway. The electrolytic hydrogen-fueled FC PHEVs offer decreased energy use relative to the corresponding non-PHEV hydrogen pathways due to the increased efficiency of the all-electric driving mode and slight (10%) improvements in fuel economy due to hybridization during fuel cell-powered VMT (see Section 4.2.2). Unlike the corresponding non-PHEV pathways, the electrolytic hydrogen-fueled PHEV pathways actually offer small reductions in fossil energy use (approx. 10-25%) relative to the baseline.

This section also includes four pathways representing the use of energy from remote stranded renewable resources (see Section 3.4.3). As would be expected, these pathways offer the largest energy use reduction benefits compared to the baseline pathway as they derive nearly all of their energy inputs from renewables. Thus, the pathway representing GH2 derived from electrolysis at remote stranded renewables pipelined to demand centers nearly eliminates both fossil and petroleum energy use, with any remaining fossil and petroleum inputs representing energy used to propel hydrogen along the pipeline and compress the GH2 at fueling stations for storage and fueling. Total energy inputs for this pathway are also nearly 50% less than the baseline and are almost entirely derived from renewable energy inputs. Interestingly, the pathway representing a PHEV fueled with GH2 from remote renewables and electricity from the 'high renewables' electricity mix (see Section 3.4.2) actually has higher fossil energy inputs than the corresponding non-PHEV pathway due to the increased reliance on fossil-derived electricity. Finally, the two BEVs using electricity derived from remote renewables offer by far the best overall energy use profiles, relying (almost) entirely on renewable energy inputs[339] and offering total energy use 75-85% less than the baseline.

[339] The electricity from remote renewables transmitted via H2 pipeline pathway uses an insignificant amount of fossil and petroleum energy associated with propelling the H2 down the pipeline.

The discussion of WtW results for energy use above illustrates the importance of using different metrics to compare WtW energy inputs. Where renewable energy inputs are involved (i.e. biomass or renewable electricity), fossil energy use should be used as the energy metric to compare alternative WtW pathways, as renewable energy inputs are not subject to resource depletion concerns. However, renewable energy inputs may be useful as indicators of land use requirements or of the scale of renewable resource needed, and total energy can thus be an appropriate metric for comparisons between similar renewable energy-based pathways. Finally, where reducing petroleum energy use is the primary concern, petroleum energy is the appropriate metric for comparison, rather than fossil energy, as substituting another (perhaps domestically available) fossil energy source (i.e., coal or natural gas) for petroleum may be acceptable.

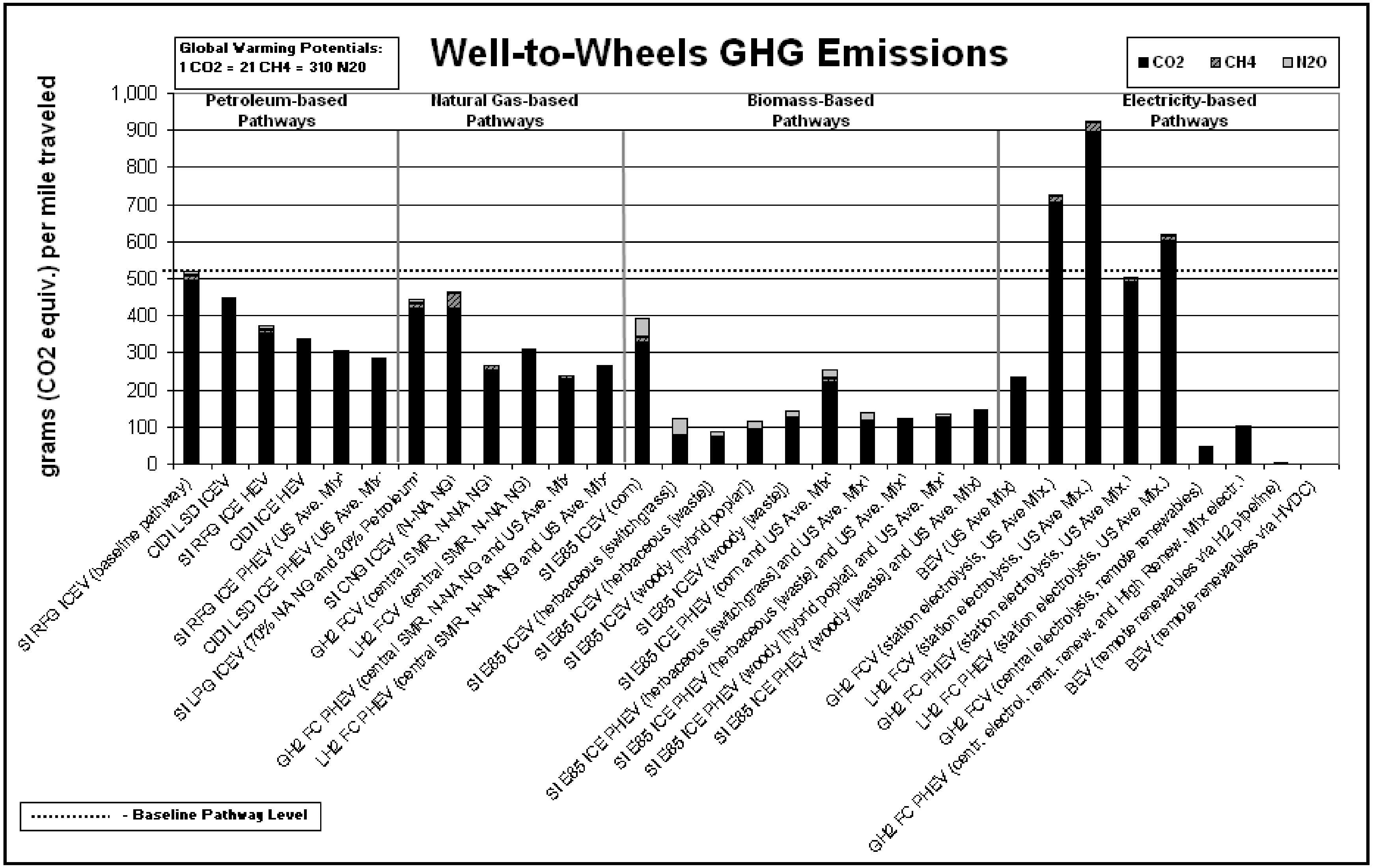
5.2 Well-to-Wheels Greenhouse Gas Emissions

Figure 5-2 below summarizes the WtW GHG emissions for the 31 selected pathways. GHG emissions are presented in global warming potential-weighted units (i.e., one gram [g] CO_2 = 21 g CH_4 = 310 g N_2O, see Section 2.4). Figure 5-2 illustrates that all of the alternative fuel and vehicle propulsion systems pathways, excepting the electrolytic hydrogen pathways, offer reductions in WtW GHG emissions. Fuel combustion during vehicle operation is responsible for 70-80% of total WtW GHG emissions for the petroleum-fueled pathways and emissions reductions for these pathways are thus predominately due to increases in PtW fuel economy. Increased WtP fuel production efficiency also contributes to decreased emissions for LSD-fueled pathways. GHG emissions reductions for petroleum-fueled PHEVs are slightly less pronounced than the energy use reductions achieved by PHEVs discussed above, due to the predominance of GHG-intensive coal-fired power plants in the US generating mix. This tempers somewhat the GHG reductions due to increased PtW fuel economy achieved by PHEVs.

The LPG and CNG pathways offer GHG reductions roughly comparable to those offered by the CIDI LSD pathway. Non-combustion CH_4 emissions from the feedstock recovery and transportation stage (i.e., CH_4 leakage during recovery and LNG boil-off during transport of N-NA NG, see Section 3.2.1) contribute 22% of total WtW GHG emissions for the CNG pathway and are much higher than the baseline pathway in absolute terms. However, these fuel recovery-related emissions are offset by reductions in both the fuel production and vehicle operation stages. The reductions in the LPG pathway are due almost entirely to the increased efficiency of the fuel production stage relative to the RFG production for the baseline pathway. FCVs fueled with hydrogen produced via steam methane reforming (SMR) of natural gas offer GHG emissions reductions of 40-50% relative to the baseline due to the fact that FCVs result in zero GHG (or other) emissions during the PtW vehicle operation stage. The majority of GHG emissions for these pathways come from CO_2 emissions during hydrogen production via SMR. PHEVs fueled with hydrogen from SMR of NG result in moderate improvements in GHG emissions relative to their non-PHEV counterparts due to increased PtW efficiency.

This study finds that the corn ethanol pathway offers a nearly 25% reduction in GHG emissions. While significant, this reduction pales in comparison to the 70-80% reductions achieved by the cellulosic ethanol pathways. The difference in the corn and cellulosic ethanol pathways is predominately due to the use of coal and natural gas for process energy

Figure 5-2: Well-to-Wheels Greenhouse Gas Emissions



in the corn ethanol production stage (see Section 3.3.4). As mentioned above, cellulosic ethanol production utilizes the lignin in the biomass feedstock for process energy, eliminating the use of fossil fuels during the fuel production stage. The GHG reductions for the ethanol-fueled pathways take into account credits for CO_2 uptake during feedstock growth and, in the case of cellulosic ethanol pathways, credits for soil carbon sequestration in biomass farms (see Section 3.3.2). Thus, the WtP GHG emissions totals for the ethanol pathways are actually negative, offsetting part of the combustion emissions of CO_2 during vehicle operation to reflect the amount of CO_2 contained in the burnt ethanol portion of the fuel originally absorbed from the atmosphere. The remaining PtW CO_2 emissions are thus due to the combustion of the RFG portion of E85 blends. Finally, in addition to combustion emissions of CO_2, non-combustion emissions of N_2O from the feedstock production stage (i.e., farming) contribute noticeably to total GHG emissions. This study finds that ethanol pathways offer the lowest total WtW GHG emissions of any group of pathways, excluding those relying exclusively on energy form remote renewables.

Due to the low WtW GHG emissions for the cellulosic ethanol pathways and the relatively GHG intensive WtP electricity pathway, cellulosic ethanol-fueled PHEVs do not offer noticeable improvements in GHG emissions over equivalent non-PHEV pathways. However, the corn ethanol PHEV pathway does cut GHG emissions by nearly 36% relative to the non-PHEV ethanol pathway and over 50% relative to the baseline pathway.

As in the case of energy use (see above), BEVs and electrolytic-hydrogen fueled FCVs result in very different GHG emissions profiles. The BEV pathway utilizing electricity from the grid results in GHG emissions 55% less than the baseline pathway. These significant reductions are again due to the high efficiency of electric vehicles' PtW vehicle operation stage, which overcomes the GHG-intensive, coal-dominated U.S. electricity mix and the inefficiencies of the WtP electricity production pathways (see Table 3-16). In contrast, the electrolytic hydrogen pathways are the only alternative pathways to result in increased GHG emissions – in this case, sizable increases of 40-80%. This is due to the inefficiencies of the WtP electrolytic hydrogen production pathways and the GHG-intensive US electricity mix. The electrolytic hydrogen-fueled PHEV pathways manage to reduce GHG emissions from the electrolytic hydrogen pathway to levels comparable to the baseline. However, they do not result in noticeable reductions in total emissions compared to the baseline pathway.

As in the case of energy use, the remote renewables-based pathways offer the lowest GHG emissions profiles. The remote renewables to GH2 pathway results in GHG reductions of 90%, for example, with the remaining emissions due to electricity from the U.S. mix used to propel hydrogen during pipelining. The hydrogen-fueled PHEV with electricity from the high renewables mix and hydrogen from remote renewables has higher GHG emissions than the non-PHEV equivalent. This is due to the fact that very little GHG emissions are associated with the remote renewables to GH2 pathway, while the high renewables electricity mix is relatively GHG-intensive (see Section 3.4.2). Finally, as would be expected, the pathways representing remote renewables to electricity for use in BEVs result in the lowest

GHG emissions of all pathways with both pathways resulting in, for all intents and purposes, zero GHG emissions.[340]

5.3 Well-to-Wheels Criteria Pollutant Emissions

This section discusses criteria pollutant emissions resulting from the 31 selected WtW pathways. Criteria pollutants are those pollutants that are regulated by the U.S. Environmental Protection Agency (EPA) under the National Ambient Air Quality Standards.[341] This study divides criteria pollutant emissions into total emissions – i.e., those emissions occurring anywhere – and urban emissions, a subset of total emissions representing any emissions occurring in urban areas. Urban areas, as defined by GREET and this study, are consistent with the U.S. Bureau of the Census' definition of metropolitan areas with populations over 125,000. Because population exposure to criteria pollutants is an important factor in gauging the impact (i.e., health effects) of these pollutants, GREET separates urban emissions values to provide an approximate metric for the health effects of criteria pollutants.[342] This study considers five criteria pollutants discussed below: VOCs, CO, NO_x, PM10, and SO_x.

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[340] The remote renewables to electricity via H2 pipeline and high temp fuel cell power plant pathway results in just over 3 grams of GWP-weighted GHG emissions per mile traveled due to the use of electricity from the grid to propel the hydrogen during pipelining. This is the equivalent of a 99.5% reduction over the baseline pathway.

[341] See EPA, "National Ambient Air Quality Standards (NAAQS)". Note: The EPA does not directly regulate VOCs but rather ground level ozone which VOCs contribute to the formation of. The EPA also regulates lead, although with the adoption and ubiquitous use of unleaded fuels, lead is no longer a significant byproduct of light-duty vehicle operations.

[342] See GM, ANL, et al. (2005) p. 96. A detailed assessment of the health effects of criteria pollutants would require extensive analysis and is beyond the scope of this study. The separation of urban and total criteria pollutant emissions is merely intended to provide an approximation and serve as a first step towards a full assessment of human health effects due to exposure to criteria pollutant emissions. Determining the exact environmental effects of criteria pollutants – i.e., acid rain, etc. – would also require further analysis beyond the scope of this study.

5.3.1 Total/Urban VOC Emissions

Figure 5-3 below presents WtW emissions of volatile organic compounds (VOCs) for the 31 selected pathways broken down by urban and non-urban emissions. VOCs, along with NO_x (see below), are precursors to ground-level ozone (smog) formation. VOC emissions here includes all hydrocarbon varieties and does not differentiate between the ozone-forming potential of different varieties of VOCs.[343] Thus, VOC emissions from different fuel/vehicle system combinations may have varying impacts. However, this metric is intended to provide an approximate indicator of the ozone-forming potential of emissions from WtW stages. Figure 5-3 illustrates the importance of the volatility of fuels in determining WtW VOC emissions. As the bulk of VOC emissions are the result of non-combustion emissions due to spillage and evaporation of fuels during WtP fuel transportation stages and PtW vehicle fueling and operation, the volatility of the fuels directly impacts the total VOC emissions. Diesel, LPG and CNG, for example, are non-volatile and result in very little evaporative VOC emissions (or none at all in the case of diesel). In contrast, ethanol is a very volatile fuel, contributing to the increase in total VOC emissions for non-PHEV ethanol pathways. The ethanol production stage also contributes significant amounts of VOC emissions. However, as the bulk of the WtP ethanol pathways (i.e., feedstock farming, ethanol production, etc.) is located in rural areas, urban VOC emissions for the ethanol pathways are actually slightly less than the baseline. Finally, electricity and hydrogen themselves result in zero PtW VOC emissions, although small amounts of VOCs may be emitted during upstream stages (i.e. transport of fuels, use of petroleum, or to a lesser degree, natural gas, for electricity generation, etc.).

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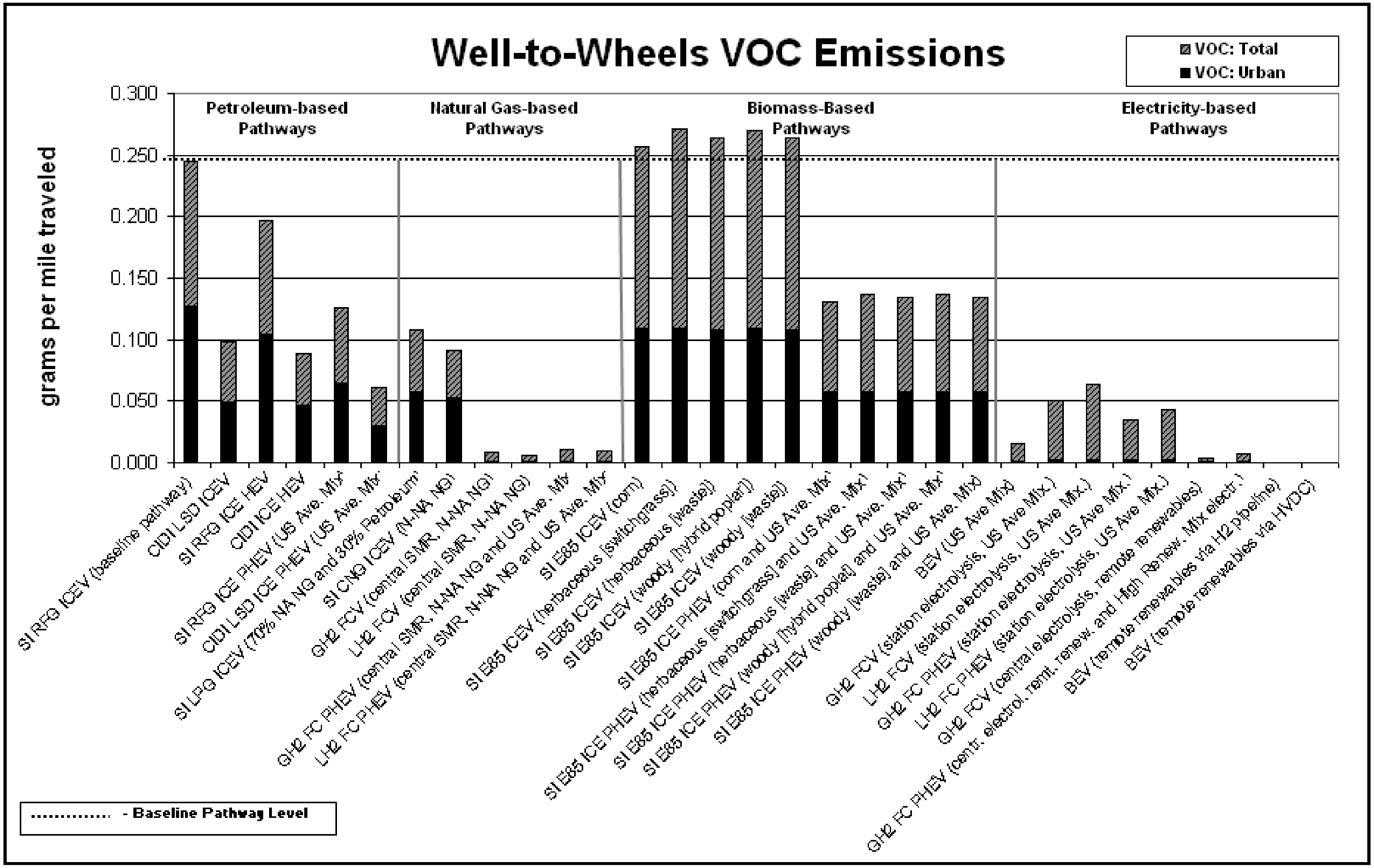
[343] See GM, ANL, et al. (2005), p. 95.

Figure 5-3: Well-to-Wheels VOC Emissions



5.3.2 Total/Urban CO Emissions

Figure 5-4 below summarizes WtW emissions of carbon monoxide (CO). CO is a colorless and odorless poisonous gas that results from the incomplete combustion of carbon in fuels. As can be seen from Figure 5-4, urban CO emissions results are divided into three tiers: ICE vehicles which all release approximately the same amount of CO (i.e., amounts in compliance with EPA Tier 2, Bin 5 standards); battery electric and hydrogen fuel cell vehicles which produce no WtP CO emissions; and PHEVs which are somewhere in-between representing the fact the approx. one third of all VMT in PHEVs are driven in all-electric mode with no fuel combustion emissions. Non-urban emissions are largely the result of fuel combustion emissions during either non-urban PtW vehicle operation or during WtP transportation of fuels and feedstocks. Combustion emissions for electricity generation contribute small amounts of CO emissions to the electricity-based WtW pathways, as well.

5.3.3 Total/Urban NO_x Emissions

Figure 5-5 below presents the WtW total and urban emissions of oxides of nitrogen (NO_x) for the 31 selected pathways. NO_x are produced during high temperature combustion processes. Along with VOCs (see above), NO_x contribute to ground-level ozone formation (smog). NO_x also contribute to the formation of acid rain and atmospheric haze and can cause respiratory illnesses. Additionally, one oxide of nitrogen, nitrous oxide (N_2O) contributes to global warming and is included amongst the GHG emissions analyzed by this study (see 5.1.2 above).

Figure 5-4: Well-to-Wheels CO Emissions

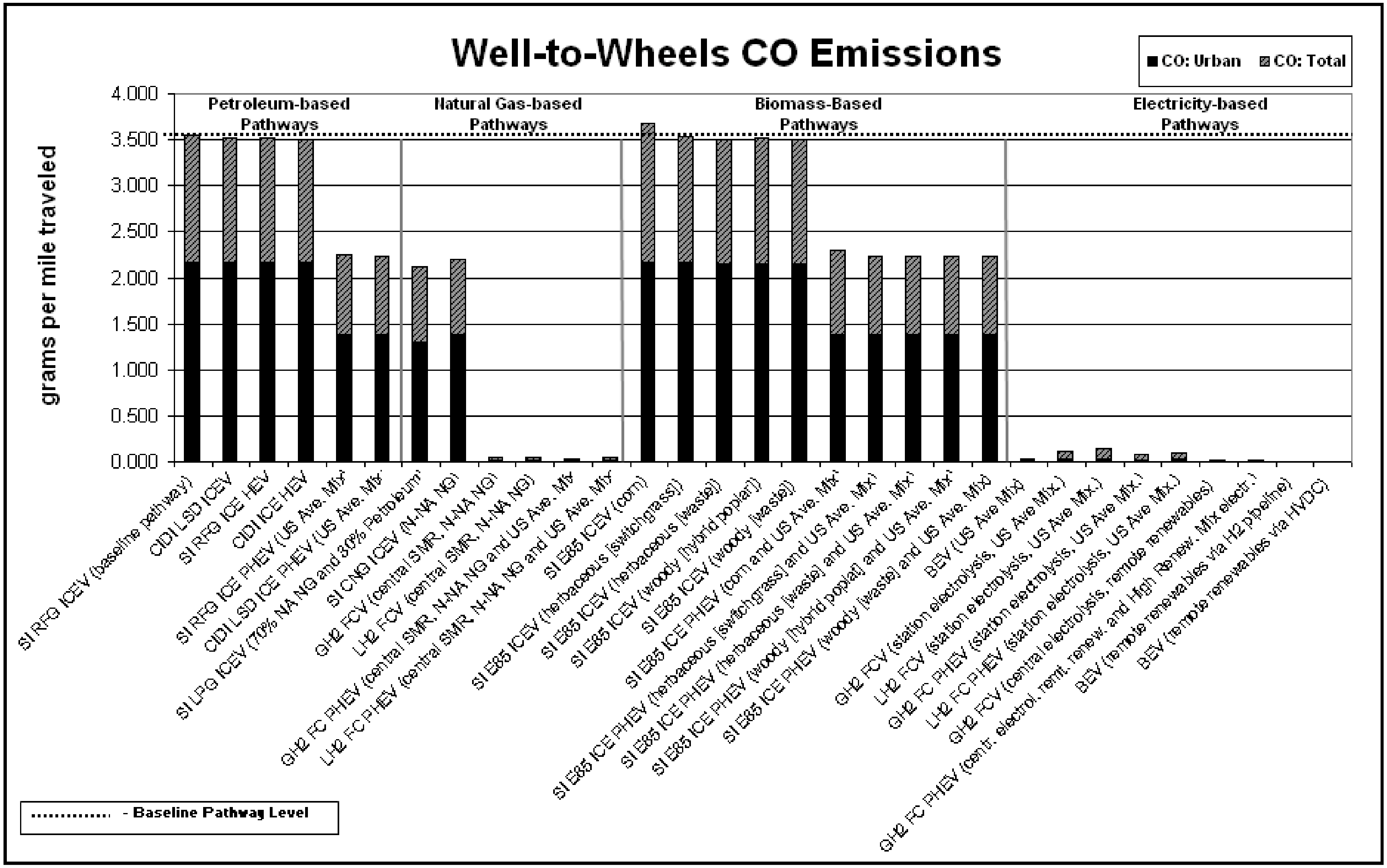


Figure 5-5: Well-to-Wheels NOx Emissions

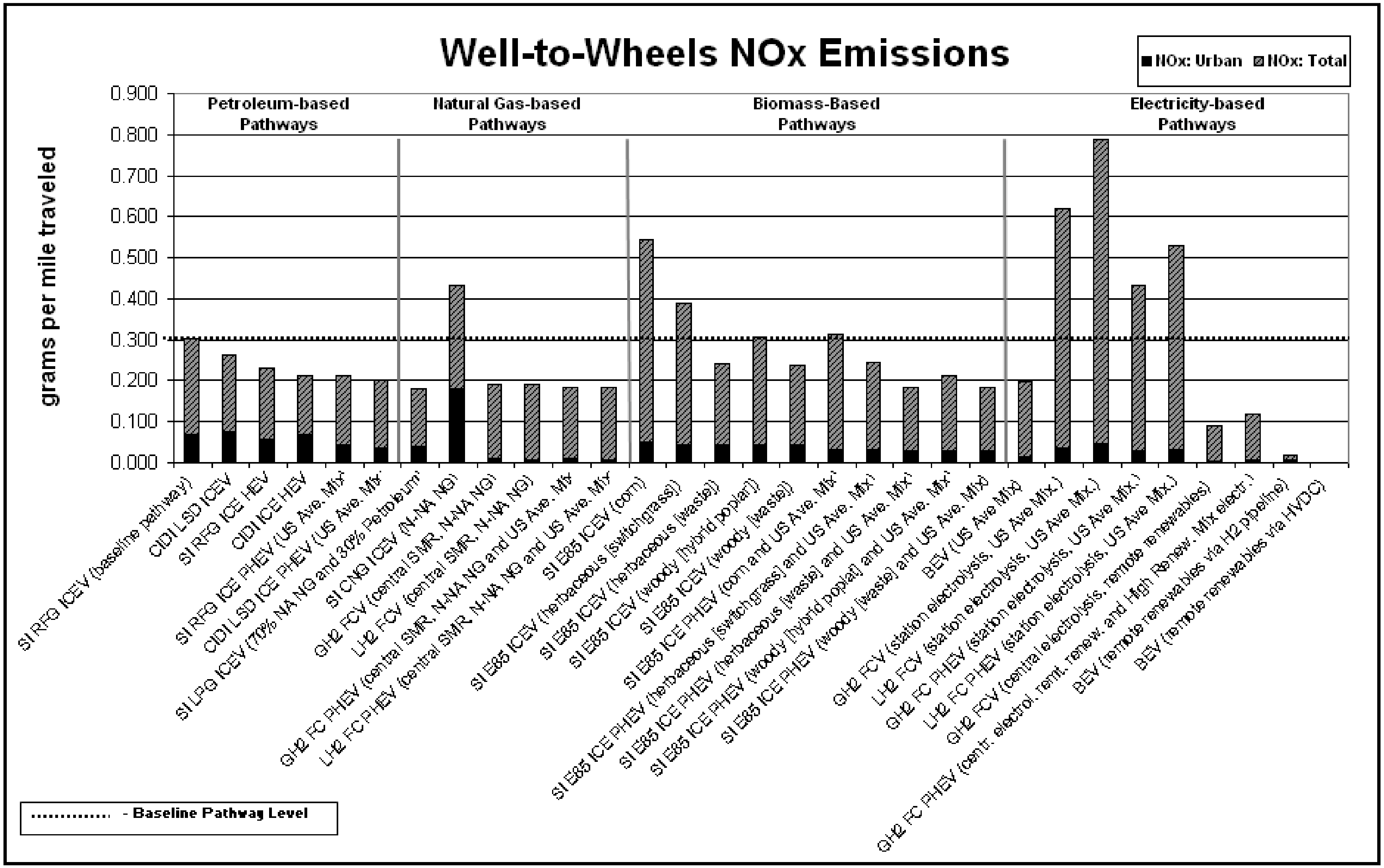


Figure 5-5 illustrates that the alternative petroleum-fueled pathways offer incremental reductions in NO_x relative to the baseline vehicle. As in the case of other metrics, these reductions are largely due to increased PtW fuel economy and the corresponding reduction in total WtW emissions (i.e. less fuel is needed for each mile traveled, thus reducing corresponding WtP emissions). The higher WtP efficiency of the LSD fuel production pathway also contributes to lower NO_x emissions although this is offset somewhat by the higher PtW vehicle operation emissions of NO_x for diesel vehicles.

While the LPG pathway results in NO_x emissions approx. 40% lower than the baseline, the CNG from non-North American (N-NA) natural gas pathway results in emissions over 40% higher than the baseline pathway. The bulk of these emissions are related to the trans-oceanic transportation of non-North American natural gas as LNG. NO_x emissions related to the transportation of LNG also contributes the bulk of emissions for the hydrogen from N-NA natural gas pathways. However, these pathways offer NO_x emissions reductions 36% below the baseline due to the PtW efficiency of FCVs and the absence of NO_x emissions during vehicle operation. The PHEV vehicles fueled with hydrogen from natural gas do not offer noticeable decreases in emissions relative to their non-PHEV counterparts. This is due to the NO_x-intensive nature of the electricity production pathways.

The ethanol pathways from farmed crops (i.e., corn, switchgrass and hybrid poplars) result in increases in NO_x emissions due to dramatically higher WtP emissions of NO_x. These emissions are largely the result of farming activities including nitrification and denitrification of nitrogen fertilizer in agricultural fields. NO_x emissions from corn and cellulosic ethanol plants also contribute to all of the biomass-based pathways.

The electrolytic hydrogen pathways also result in higher NO_x emissions, in this case dramatically higher emissions 40-160% above the baseline pathway. This is due to the inefficiency of the WtP stages and the reliance on U.S. average mix electricity, which results in significant NO_x emissions from fossil-fired power plants (particularly coal-fired plants). The BEV with grid electricity pathway overcomes the NO_x-intensive electricity mix with high PtW efficiency, offering a 35% reduction in total NO_x emissions relative to the baseline. Finally, all of the remote renewables-based pathways result in little or no NO_x emissions, as would be expected, with any remaining emissions associated with electricity used to propel or compress hydrogen.

This study finds that the WtP stage accounts for the bulk (70% or more) of the WtW emissions of NO_x for all of the pathways considered. This is because all vehicle propulsion systems are assumed to comply with stringent EPA Tier 2, Bin 5 emissions standards for NO_x (see Section 2.3) and several pathways (i.e., hydrogen and electricity-fueled pathways) result in zero PtW NO_x emissions. This study thus highlights the fact that further reductions of WtW NO_x emissions will require the reduction of NO_x emissions from WtP processes. Finally, it must be noted that NO_x emissions for pathways reliant on electricity from the U.S. generating mix would be higher in the absence of increasingly strict emissions control standards for U.S. power plants (i.e., the Clean Air Interstate Rule, see Section 3.4.2).

5.3.4 Total/Urban PM10 Emissions

Figure 5-6 below summarizes WtW emissions of PM10. PM10 refers to particulate matter emissions smaller than 10 microns in diameter. Particulate matter causes adverse health effects (particularly to the lungs and heart) and is a main contributor to atmospheric haze. As can be seen in Figure 5-5, PM10 emissions for the corn ethanol pathways are much higher than the baseline. This is due to the large amounts of non-combustion particulate emissions resulting from farming operations (i.e., tillage of fields) as well as non-combustion PM10 emissions during ethanol production. Furthermore, Figure 5-6 makes it clear that any pathway relying on electricity from the U.S. average mix results in significant increases in PM10 emissions. This is due to the large amounts of particulate matter emitted by the coal-fired power plants that dominate the U.S. electricity mix as well as the large PM10 emissions associated with mining and cleaning the coal that feeds these plants. In fact, PM10 emissions and SO_x discussed below are the only times when the BEV fueled with electricity from the U.S. average mix pathway results in higher emissions than the baseline. Furthermore, for these two emissions metrics, PHEVs actually result in increases in emissions over their non-PHEV counterparts in most cases (with exceptions being the already PM10-intensive pathways such as the corn ethanol and electrolytic hydrogen pathways). It must also be noted that the electrolytic hydrogen pathways result in huge increases in PM10 emissions between seven and ten times higher than the baseline pathway. Alternative pathways result in urban PM10 emissions reductions ranging between 10 and 58% below the baseline pathway. However, unlike with some other emissions, all pathways result in at least some PtW PM10 emissions due to tire and brake wear during vehicle operation. This limits the total PM10 reductions achievable by any pathway.

5.3.5 Total/Urban SO_x emissions

Figure 5-7 below summarizes WtW emissions of oxides of sulfur (SO_x) for the 31 selected pathways. As Figure 5-7 illustrates, use of electricity from the U.S. generation mix is the largest factor contributing to increased SO_x emissions in a number of pathways. This is

Figure 5-6: Well-to-Wheels PM10 Emissions

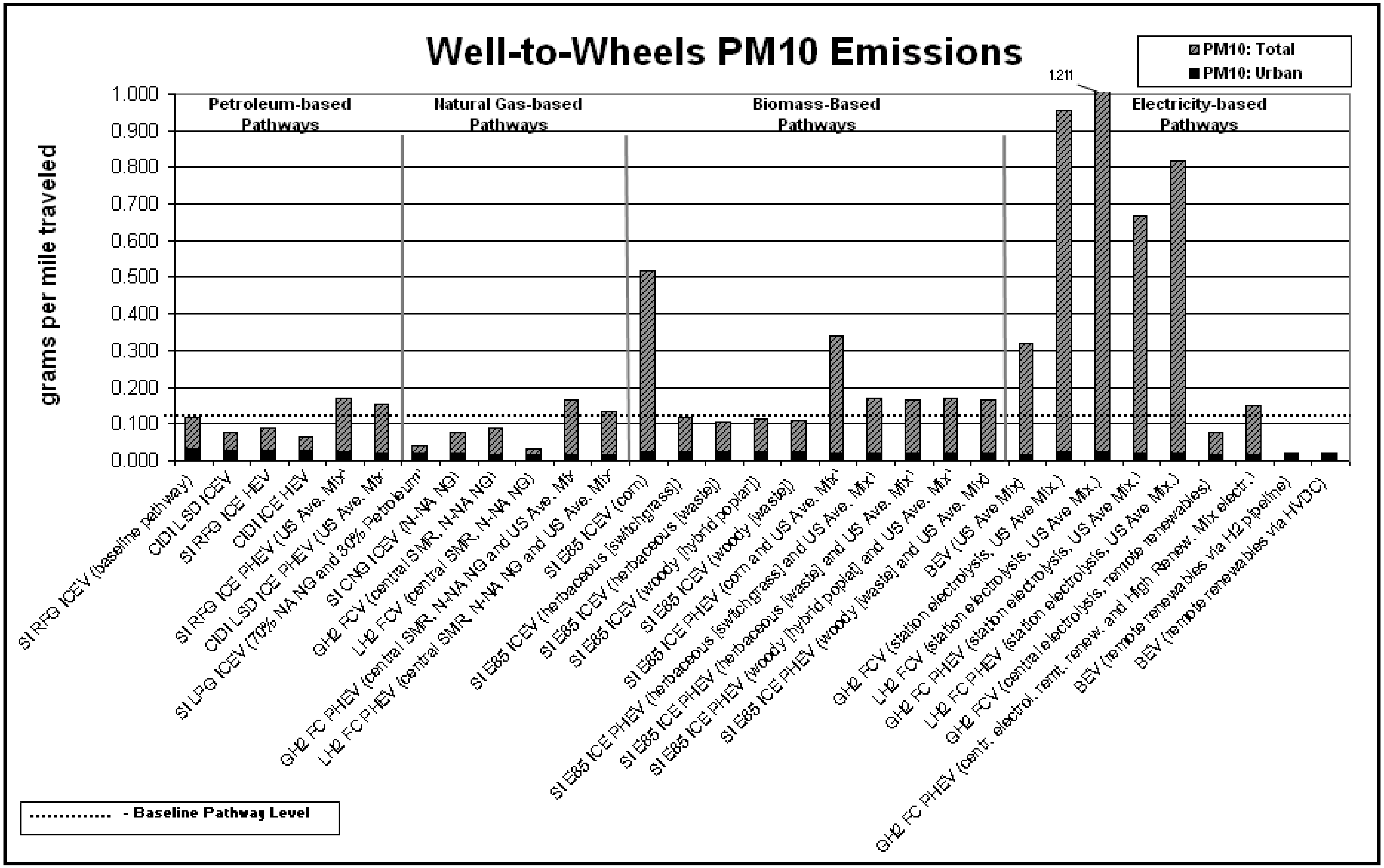
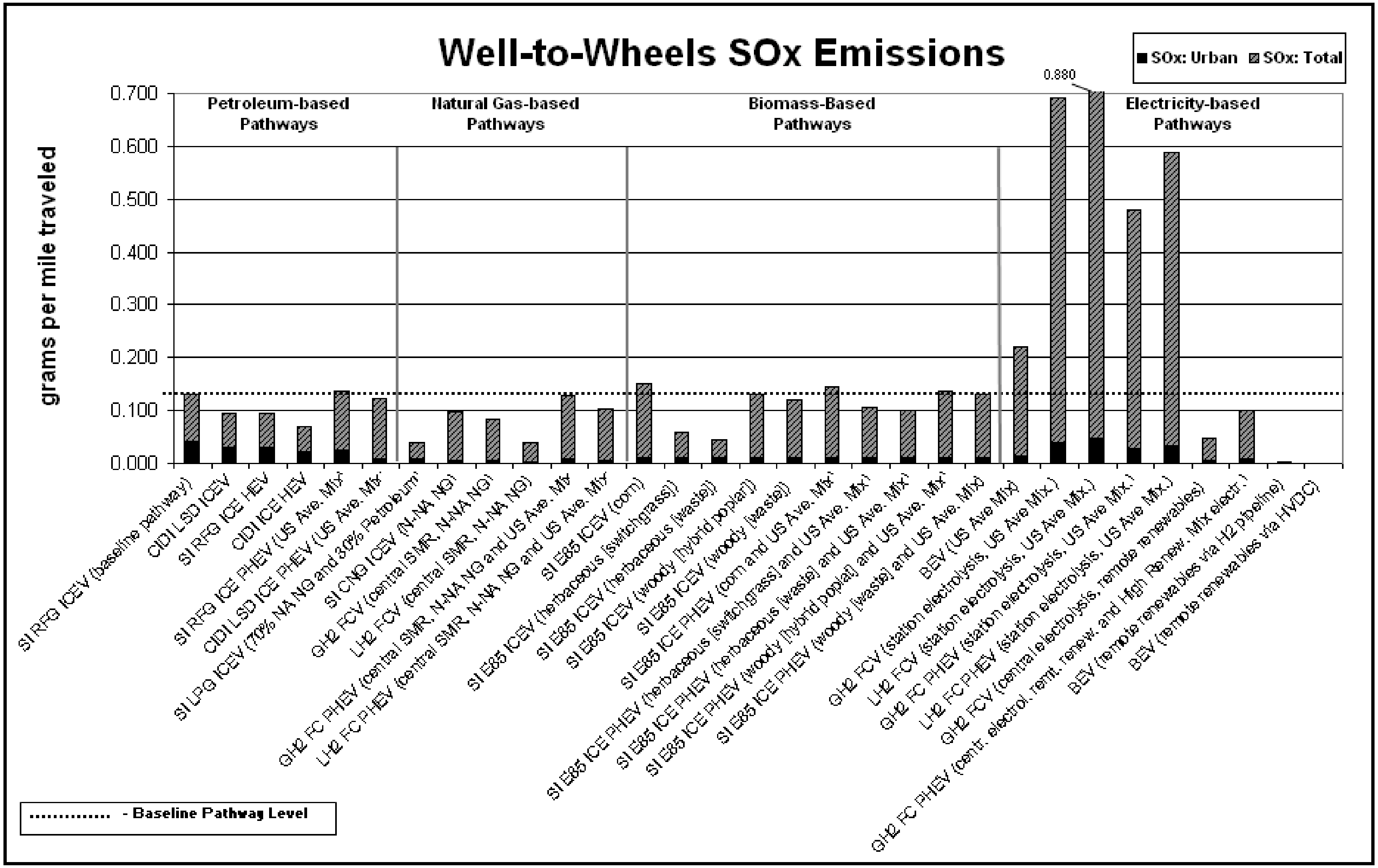


Figure 5-7: Well-to-Wheels SOx Emissions



due to the large quantities of SO_x emitted at the United States' many coal-fired power plants (and to a lesser degree, other fossil-fired plants). In particular, the electrolytic hydrogen pathways result in huge increases in SO_x emissions between four and five times higher than the baseline. As mentioned above, the BEV pathway fueled with electricity from the U.S. average mix also results in an increase in SO_x emissions (about two-thirds higher than the baseline) making SO_x emissions one of only two metrics where this pathway performs worse than the baseline pathway. Furthermore, in most cases, PHEV pathways actually result in higher SO_x emissions than the equivalent non-PHEV pathway. As in the case of NO_x, these increases in SO_x emissions for pathways reliant on electricity from the grid would be more pronounced without the implementation of increasingly stricter emissions standards for U.S. power plants (i.e., the Clean Air Interstate Rule, see Section 3.4.2).

WtW urban SO_x emissions are dominated by emissions from PtW vehicle operation, although emissions from power plants located within urban areas also contributes somewhat to urban SO_x emissions for the electricity-based pathways. However, despite overall increases in total SO_x emissions for many pathways, all pathways (excepting the electrolytic liquid hydrogen FCV pathway) result in decreases in urban SO_x emissions relative to the baseline pathway due to reduced PtW vehicle operations emissions of sulfur.

5.4 Changes in WtW Energy Use and Emissions Relative to the Baseline Pathway

This section presents relative changes in energy use and emissions of GHGs and criteria pollutants for the 31 selected pathways. These results are presented in tabular form in Table 5-3 below. All values are presented relative to the baseline vehicle. This table should illustrate the relative costs and benefits of replacing some or all of our predominately SI RFG ICEV-dominated light-duty vehicle fleet with one or more of the alternative pathways presented in this section.

Table 5-3: Changes in Well-to-Wheels Energy Use and Emissions Relative to the Baseline Pathway

	Petroleum-based Pathways					
Well-to-Wheels Results Relative to Baseline Pathway	***SI RFG ICEV (baseline pathway)***	***CIDI LSD ICEV***	***SI RFG ICE HEV***	***CIDI ICE HEV***	***SI RFG ICE PHEV (US Ave. Mix)***	***CIDI LSD ICE PHEV (US Ave. Mix)***
Total Energy	0.00%	-20.24%	-28.57%	-40.18%	-44.06%	-50.65%
Fossil Fuels	0.00%	-17.95%	-28.57%	-38.47%	-45.43%	-51.00%
Petroleum	0.00%	-15.25%	-28.57%	-36.44%	-57.01%	-61.37%
CO2	0.00%	-12.20%	-28.58%	-34.15%	-40.98%	-43.95%
CH4	0.00%	-28.63%	-25.21%	-45.96%	-38.10%	-50.58%
N2O	0.00%	-49.98%	-5.26%	-50.83%	-36.93%	-65.45%
GHGs	0.00%	-13.62%	-27.89%	-34.91%	-40.79%	-44.69%
VOC: Total	0.00%	-59.59%	-19.58%	-63.46%	-48.52%	-74.79%
CO: Total	0.00%	-0.79%	-0.87%	-1.35%	-36.68%	-36.95%
NOx: Total	0.00%	-13.80%	-24.34%	-29.58%	-30.62%	-33.15%
PM10: Total	0.00%	-32.45%	-22.74%	-44.46%	47.07%	34.33%
SOx: Total	0.00%	-28.50%	-28.57%	-46.38%	3.42%	-6.89%
VOC: Urban	0.00%	-61.38%	-17.68%	-63.49%	-49.38%	-76.88%
CO: Urban	0.00%	-0.22%	-0.29%	-0.40%	-36.55%	-36.90%
NOx: Urban	0.00%	8.02%	-16.47%	-2.51%	-42.62%	-50.33%
PM10: Urban	0.00%	-8.32%	-13.36%	-18.52%	-28.10%	-40.66%
SOx: Urban	0.00%	-30.67%	-28.57%	-48.01%	-47.30%	-87.03%

***Table 5-3: Changes in Well-to-Wheels Energy Use and Emissions Relative to the Baseline Pathway* (Continued)**

	Natural Gas-Based Pathways						**Biomass-based Pathways**				
Well-to-Wheels Results Relative to Baseline Pathway	***SI LPG ICEV (70% NA NG and 30% Petroleum)***	***SI CNG ICEV (N-NA NG)***	***GH2 FCV (central SMR, N-NA NG)***	***LH2 FCV (central SMR, N-NA NG)***	***GH2 FC PHEV (central SMR, N-NA NG and US Ave. Mix)***	***LH2 FC PHEV (central SMR, N-NA NG and US Ave. Mix)***	***SI E85 ICEV (corn)***	***SI E85 ICEV (herbaceous [switchgrass])***	***SI E85 ICEV (herbaceous [waste])***	***SI E85 ICEV (woody [hybrid poplar])***	***SI E85 ICEV (woody [waste])***
Total Energy	-13.97%	-0.77%	-43.10%	-29.22%	-53.56%	-45.53%	24.09%	29.57%	24.66%	34.30%	32.67%
Fossil Fuels	-11.27%	1.71%	-42.28%	-26.92%	-54.46%	-45.58%	-34.63%	-71.39%	-76.33%	-74.82%	-76.47%
Petroleum	-70.00%	-98.76%	-98.90%	-99.08%	-98.79%	-98.89%	-73.17%	-74.56%	-76.11%	-74.92%	-76.26%
CO2	-15.03%	-15.40%	-49.38%	-39.00%	-54.10%	-48.10%	-33.92%	-86.18%	-87.01%	-82.34%	-75.94%
CH4	-3.19%	205.32%	7.58%	-35.97%	-20.80%	-45.98%	3.91%	-53.78%	-60.78%	-59.06%	-60.75%
N2O	-16.34%	-54.20%	-96.02%	-92.80%	-94.34%	-92.47%	291.13%	250.37%	43.13%	64.98%	49.97%
GHGs	-14.73%	-10.26%	-48.99%	-40.29%	-54.21%	-49.17%	-24.55%	-76.66%	-82.94%	-77.92%	-72.30%
VOC: Total	-55.73%	-62.83%	-96.44%	-97.32%	-95.55%	-96.05%	5.09%	10.87%	8.14%	10.36%	8.16%
CO: Total	-40.31%	-38.07%	-98.79%	-98.53%	-98.95%	-98.79%	3.78%	-0.35%	-1.22%	-0.58%	-1.17%
NOx: Total	-40.45%	42.79%	-36.89%	-36.83%	-39.68%	-39.64%	78.96%	27.64%	-20.83%	0.30%	-21.52%
PM10: Total	-66.37%	-33.75%	-23.81%	-72.25%	44.09%	16.08%	348.84%	1.95%	-8.23%	-2.57%	-7.10%
SOx: Total	-70.39%	-27.16%	-37.73%	-70.31%	-2.98%	-21.82%	14.89%	-54.96%	-66.92%	-1.32%	-9.15%
VOC: Urban	-55.50%	-59.16%	-99.84%	-99.82%	-99.78%	-99.76%	-14.22%	-14.34%	-14.60%	-14.48%	-14.61%
CO: Urban	-40.42%	-37.09%	-99.90%	-99.93%	-99.89%	-99.91%	-0.55%	-0.66%	-0.76%	-0.74%	-0.76%
NOx: Urban	-45.14%	168.78%	-88.74%	-96.63%	-87.50%	-92.06%	-28.91%	-38.16%	-41.22%	-40.41%	-41.28%
PM10: Urban	-43.99%	-43.13%	-51.31%	-52.19%	-54.42%	-54.93%	-24.29%	-31.33%	-32.38%	-31.85%	-32.24%
SOx: Urban	-87.44%	-92.14%	-94.77%	-99.96%	-86.68%	-89.69%	-77.21%	-75.89%	-77.66%	-76.67%	-77.76%

***Table 5-3: Changes in Well-to-Wheels Energy Use and Emissions Relative to the Baseline Pathway* (continued)**

	Biomass-based Pathways (continued)					***Electricity-based Pathways***				
Well-to-Wheels Results Relative to Baseline Pathway	***SI E85 ICE PHEV (corn and US Ave. Mix)***	***SI E85 ICE PHEV (herbaceous [switchgrass] and US Ave. Mix)***	***SI E85 ICE PHEV (herbaceous [waste] and US Ave. Mix)***	***SI E85 ICE PHEV (woody [hybrid poplat] and US Ave. Mix)***	***SI E85 ICE PHEV (woody [waste] and US Ave. Mix)***	***BEV (US Ave Mix)***	***GH2 FCV (station electrolysis, US Ave Mix.)***	***LH2 FCV (station electrolysis, US Ave Mix.)***	***GH2 FC PHEV (station electrolysis, US Ave Mix.)***	***LH2 FC PHEV (station electrolysis, US Ave Mix.)***
Total Energy	-33.84%	-31.52%	-33.61%	-29.51%	-30.21%	-62.81%	16.09%	47.79%	-19.33%	-1.00%
Fossil Fuels	-60.12%	-75.71%	-77.81%	-77.16%	-77.87%	-66.58%	4.32%	32.80%	-27.51%	-11.04%
Petroleum	-88.05%	-88.63%	-89.30%	-88.79%	-89.36%	-98.42%	-95.06%	-93.71%	-96.56%	-95.78%
CO2	-55.37%	-77.53%	-77.87%	-75.90%	-73.17%	-54.31%	42.61%	81.47%	-0.90%	21.57%
CH4	-35.19%	-59.66%	-62.65%	-61.90%	-62.63%	-53.30%	45.75%	85.47%	1.28%	24.25%
N2O	86.54%	69.26%	-18.97%	-9.37%	-16.06%	-90.76%	-71.15%	-63.29%	-79.95%	-75.40%
GHGs	-51.17%	-73.27%	-75.94%	-73.81%	-71.42%	-55.22%	39.78%	77.88%	-2.87%	19.16%
VOC: Total	-46.36%	-43.91%	-45.08%	-44.13%	-45.07%	-93.42%	-79.46%	-73.87%	-85.73%	-82.49%
CO: Total	-35.08%	-36.83%	-37.20%	-36.92%	-37.18%	-99.02%	-96.95%	-96.12%	-97.88%	-97.40%
NOx: Total	2.86%	-18.90%	-39.59%	-30.50%	-39.88%	-34.52%	104.37%	160.06%	42.01%	74.22%
PM10: Total	194.28%	47.16%	42.82%	45.25%	43.30%	175.21%	726.21%	946.41%	477.84%	605.19%
SOx: Total	9.73%	-19.89%	-25.00%	2.86%	-0.50%	67.67%	423.36%	565.98%	263.67%	346.15%
VOC: Urban	-55.41%	-55.46%	-55.57%	-55.52%	-55.57%	-99.64%	-98.88%	-98.57%	-99.22%	-99.04%
CO: Urban	-36.78%	-36.83%	-36.87%	-36.86%	-36.87%	-99.86%	-99.56%	-99.44%	-99.70%	-99.63%
NOx: Urban	-54.88%	-58.80%	-60.11%	-59.76%	-60.13%	-83.54%	-48.61%	-34.61%	-64.29%	-56.19%
PM10: Urban	-35.14%	-43.28%	-43.72%	-43.58%	-43.73%	-51.37%	-33.77%	-28.61%	-44.28%	-41.30%
SOx: Urban	-80.04%	-79.48%	-80.24%	-79.81%	-80.28%	-71.71%	-11.71%	12.35%	-38.65%	-24.73%

Table 5-3: Changes in Well-to-Wheels Energy Use and Emissions Relative to the Baseline Pathway* (continued*)

Well-to-Wheels Results Relative to Baseline Pathway	***Electricity-based Pathways (continued)***			
	GH2 FCV (central electrolysis, remote renewables)	***GH2 FC PHEV (central electrolysis remote renew. and High Renew. Mix electricity)***	***BEV (remote renewables via H2 pipeline)***	***BEV (remote renewables via HVDC)***
Total Energy	-48.66%	-57.48%	-84.22%	-74.25%
Fossil Fuels	-93.28%	-85.49%	-100.00%	-99.56%
Petroleum	-99.37%	-99.12%	-100.00%	-99.89%
CO2	-90.99%	-80.07%	-100.00%	-99.49%
CH4	-90.96%	-79.98%	-100.00%	-99.48%
N2O	-97.79%	-95.00%	-100.00%	-99.89%
GHGs	-91.17%	-80.45%	-100.00%	-99.50%
VOC: Total	-98.57%	-96.97%	-100.00%	-99.90%
CO: Total	-99.68%	-99.47%	-100.00%	-99.96%
NOx: Total	-70.60%	-61.21%	-100.00%	-94.29%
PM10: Total	-32.66%	30.67%	-83.68%	-81.69%
SOx: Total	-64.67%	-23.99%	-100.00%	-97.64%
VOC: Urban	-99.95%	-99.86%	-100.00%	-99.98%
CO: Urban	-99.98%	-99.95%	-100.00%	-99.99%
NOx: Urban	-97.41%	-93.29%	-100.00%	-95.14%
PM10: Urban	-51.77%	-55.00%	-57.44%	-57.32%
SOx: Urban	-95.35%	-87.97%	-100.00%	-99.06%

6. CONCLUSIONS

The primary motivations for this study were to examine the potential for various alternative transportation fuels and vehicle propulsion systems to reduce petroleum consumption, GHG emissions and criteria pollutants (particularly those occurring in urban areas) resulting from the light-duty transport sector. To do so, this study conducted an analysis of several dozen full well-to-wheels (WtW) fuel/vehicle pathways and presented results using 17 different metrics including total, fossil and petroleum energy use and emissions of three GHGs (as well as total global warming potential-weighted GHGs) and total and urban emissions of five criteria pollutants.

As this study's results indicate, conducting an analysis of the full WtW pathway for the various fuel/vehicle systems considered is crucial, as upstream, or well-to-pump (WtP), stages contribute significantly to the total energy use and emissions associated with traveling one mile in a given vehicle fueled with a particular fuel. This is true even for criteria pollutant emissions as increasingly stringent vehicle tailpipe emissions regulations (i.e. new Tier 2 and low-sulfur fuel standards) continue to reduce emissions during the vehicle operation, or pump-to-wheels (PtW) stage. Additionally, it is crucial to differentiate between different types of energy inputs as much as possible as energy derived from different sources can have vastly different consequences on resource depletion concerns, energy security and foreign policy. This study thus aimed to provide a more meaningful analysis of the impacts of energy use by dividing energy inputs into total, fossil and petroleum-derived energy. Some studies only present results for total energy inputs. This can be very misleading, as pathways relying largely on renewable energy may appear very costly when total energy is the only metric examined, despite the fact that these pathways may offer considerable fossil and/or petroleum energy use reductions.

This study finds that the fuel production and vehicle operation stages are generally the two most important stages in determining WtW results for the various metrics. The fuel production stage generally has the largest energy losses and results in the most significant emissions of any upstream WtP stage. This is particularly true for petroleum-derived fuels (i.e. gasoline and diesel), ethanol from corn, and especially electricity and hydrogen. Additionally, PtW vehicle fuel economy is particularly important as it directly affects the amount of fuel consumed and thus the level of upstream WtP energy use and emissions associated with traveling one mile in a particular vehicle.

The WtW results generated by this study indicate that there are a variety of alternative fuel/vehicle system pathways that could reduce petroleum consumption related to the light-duty transport sector. All of the alternative pathways considered reduce petroleum energy use somewhat relative to the baseline pathway (i.e., a spark-ignition internal combustion engine vehicle fueled with reformulated gasoline [RFG]), while some nearly eliminate petroleum energy inputs. Alternative (non-PHEV) petroleum-fueled pathways result in petroleum energy use 15-33% less than the baseline pathway, almost entirely due to increased vehicle fuel economy. The pathways that achieve the most significant petroleum energy reductions are those that switch from petroleum to another basic energy feedstock – i.e., natural gas, biomass, or electricity (which is primarily from non-petroleum-fired power plants). Pathways that nearly eliminate petroleum energy inputs include compressed natural gas (CNG) and hydrogen derived from natural gas, as well as all electricity and electrolytic hydrogen pathways. Use of ethanol in E85-fueled vehicles also offers significant petroleum energy reductions of nearly 75% with the remaining petroleum energy use largely due to the fact that E85 contains 15% RFG by volume (and 21% by energy content).

Despite the fact that many pathways result in significant petroleum energy use reductions, several of these pathways (i.e., natural gas and electricity-based pathways) achieve these reductions by substituting other non-renewable fossil fuel-derived energy inputs. In some cases, particularly those reliant on natural gas, this may mean that these pathways offer fewer benefits than indicated by the petroleum use reductions they achieve, as natural gas is also subject to resource depletion and related concerns. Natural gas supplies in North America are already tight and any increased reliance on natural gas for transportation fuels could simply displace concerns about imported oil to concerns about imported natural gas, much of which is located in unstable areas of the world.[344]

This points to the importance of examining fossil energy use in addition to petroleum energy use. The pathways that result in the most significant fossil energy use reductions are clearly those pathways that rely on renewable energy inputs – i.e., the biomass-based ethanol pathways and the electricity-based pathways utilizing energy from remote stranded renewable resources. Several other pathways also result in significant reductions in fossil energy use between 25-65%, however, due to the overall WtW efficiency of these pathways. These include the hydrogen-from-natural gas pathways as well as the battery electric vehicle pathways and most PHEVs fueled with electricity from the U.S. generating mix. Additionally, the ethanol-from-corn pathway results in fossil energy use nearly 35% lower than the baseline due to the use of corn as a feedstock. Thus, there are several pathways that offer significant decreases in both petroleum and fossil energy consumption.

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[344] Russia, Iran, Qatar, Saudi Arabia and the United Arab Emirates rank top five in the world for proven natural gas reserves (in that order) with nearly two-thirds of total worldwide reserves amongst them. See CIA, "Rank Order – Natural Gas – proved reserves".

Nearly all of the pathways considered by this study offer some reduction in GHG emissions. GHG reductions are somewhat correlated with fossil energy reductions, although this correlation can be thrown off by the different carbon contents in the various fossil fuels. Natural gas-based pathways, for example, offer larger GHG reductions than fossil energy reductions since natural gas is 21% less carbon intensive (i.e., has 21% less carbon per Btu) than crude oil and 22% less carbon intensive than RFG. In contrast, the GHG reductions for the diesel pathways are slightly smaller than the corresponding fossil energy reductions due to the fact that low-sulfur diesel (LSD) is 6.5% more carbon intensive than RFG.

Still, as with fossil energy reductions, the pathways that offer the most significant reductions in GHG emissions are those that rely on renewable energy inputs, including the biomass-based ethanol pathways and electricity pathways utilizing remote renewables. The remote renewables-based pathways, for example, nearly eliminate GHG emissions, while the biomass-based E85 pathways offer GHG reductions between 72-83%. The remaining GHG emissions for these E85 pathways are the result of combustion of RFG contained in E85 blends.

Several other pathways that rely on feedstocks containing carbon also achieve GHG reductions, however, primarily as a result of high overall WtP efficiencies and/or low vehicle fuel consumption. The hydrogen-from-natural gas pathways and the various PHEV and BEV pathways fueled with electricity from the U.S. generating mix offer reductions on the scale of 40-50% due largely to high PtW efficiencies and zero vehicle operation emissions (or in the case of PHEVs, zero emissions during all-electric driving mode). Additionally, several other pathways, including corn-based E85, CNG, LPG, diesel and the two petroleum-fueled hybrid-electric vehicles (HEVs) offer moderate GHG reductions on the order of 10-35%. In contrast to the biomass-based E85 pathways, emissions for the corn-based E85 pathway are only moderate due to the fact that ethanol plants rely on coal and natural gas for process energy. More intensive use of agricultural chemicals (including nitrogen fertilizers which result in emissions of the potent GHG, N_2O) also diminishes the GHG reductions achieved by the corn-based E85 pathway.

Finally, it must be noted that the electrolytic hydrogen pathways are the only alternative pathways that result in increased GHG emissions. In fact, these pathways result in significant increases of approximately 40-80%, despite the fact that hydrogen itself is a carbon-free fuel and hydrogen fuel cell vehicles (FCVs) result in zero emissions of GHGs during vehicle operation. This is due to the GHG-intensive nature of the current coal-dominated U.S. electricity mix and the low WtP efficiency of electrolytic hydrogen production. As such, it may be unwise to adopt the widespread use of the electrolytic hydrogen pathways, as the world cannot afford increased GHG emissions. However, WtW GHG emissions for these pathways are highly dependent on the electricity mix. Thus, electrolytic hydrogen may be acceptable in regions with electricity mixes resulting in low GHG emissions (i.e., California or the Pacific Northwest) and is excellent when specifically utilizing renewable energy (as is evidenced by the remote renewables-to-hydrogen pathways).

This study indicates that, in general, alternative transportation fuels and vehicle propulsion systems help reduce criteria pollutant emissions associated with the light-duty transport sector. In particular, all but one of the alternative pathways results in some decrease in urban emissions of the five criteria pollutants (with the exception being urban NO_x emissions from the LSD pathway). However, several pathways result in increased total emissions of one or more criteria pollutants. The electricity-based pathways result in increased PM10 and SO_x emissions, for example. Additionally, the ethanol from farmed crops pathways result in increased emissions of NO_x and in the case of corn ethanol, a large increase in total PM10 emissions, both due to farming activities.

The criteria pollutant results thus point to the fact that trade-offs may be necessary, as several pathways that perform well in all other metrics result in increases in total emissions of one or more criteria pollutants. This study's results also point to the importance of upstream stages to WtW criteria pollutant emissions. Thus, in many cases, future efforts to reduce transportation-related criteria pollutant emissions may be forced to focus on WtP stages, rather than on vehicle tailpipe emissions (which have been the focus of increased regulation in the past few decades).

Considering this study's primary motivations, the WtW results generated by this study provide cause to be optimistic. This study demonstrates that there are several potential alternative vehicle fuels and propulsion systems that can significantly decrease petroleum energy use. The results also indicate that there are several promising options to drastically reduce GHG emissions related to the light-duty transport sector as well as emissions of several criteria pollutants. Care must be taken, however, to avoid simply substituting non-North American natural gas for petroleum use, lest the United States end up embroiled again in the negative consequences arising from reliance on a depleting energy source. Alterative fuels that rely on domestic energy sources should be preferred and renewable resources should be utilized as much as possible.

Some of the technologies and fuels analyzed in this study are ready and available today to contribute immediately to reducing petroleum and fossil energy use and emissions of GHGs and criteria pollutants. Other technologies still have unresolved technological, cost, or other hurdles and may require additional research and financial support to reach the market quickly enough to take full advantage of their potential benefits in the timeframe considered by this study (i.e., by 2025). The results presented in this study can be used as an initial indication as to which technologies should receive the most concerted effort to bring to market. Plug-in hybrid electric vehicles, ethanol derived from woody and herbaceous biomass (i.e., cellulosic ethanol) and electric vehicles all offer a particularly good range of benefits. The pathways utilizing remote stranded renewables offer by far the best benefits, although developing these resources would require large capital investments and considerable planning.

In short, this study finds that the technical options are available to allow significant reductions in petroleum and fossil energy use as well as emissions of GHGs and criteria pollutants related to the light-duty transport sector. What is needed is the development of forward thinking strategies and actions to begin a concerted and rapid transition away from the current oil-addicted light-duty transport sector towards the use of vehicles fueled with energy derived from domestically available and, as much as possible, renewable energy sources. Such vehicles and fuels could also offer dramatically reduced emissions of GHGs and pollutants. This study indicates that the requisite options are available. We must now chart the road forward.

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-Introduction to switchgrass as a feedstock for cellulosic ethanol production from Oak Ridge National Labs (ORNL). Discusses ORNL’s working on biofuels from herbaceous biomass as part of the Biofuels Feedstock Development Program.

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-One of the controversial studies published by U.C. Berkley researcher Tad Patzek (see Pimentel and Patzek (2005) below) that concludes that corn-based ethanol actually consumes more energy than it yields. This study was analyzed by Farell, et al. (2006a and 2006b) above who found that it inaccurately addressed the allocation of credits for co-products and includes some input data that is either old and poorly representative of current practice or was so poorly documented that the validity of the assumptions could not be determined.

Perlack, Robert D., et al. *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: the Technical Feasability of a Billion-Ton Annual Supply*. (Oak Ridge, TN: Oak Ridge National Laboratory, April 2005). <http://www1.eere.energy.gov/biomass/pdfs/final_billionton_vision_report2.pdf>.
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-A well-to-wheels analysis of six biomass fuel pathways using the GREET model. Study performed by Argonne National Lab as part of the multi-institution Role of Biomass in America's Energy Future Project. Focuses on three biofuels – ethanol, Fischer-Tropsch diesel (bio-FTD) and dimethyl ether bio-DME) – from cellulosic biomass feedstocks. Concludes that biofuels offer significant savings in fossil and petroleum energy consumption.

APPENDIX A

COMPLETE TABLES OF WELL-TO-WHEELS RESULTS

Table A-1: Well-to-Wheels Results

	Total Energy	**Fossil Energy**	**Petrol. Energy**	**CO_2**	**CH_4**	**N_2O**	**GHGs**	**Total VOC**	**Total CO**	**Total NO_x**	**Total PM10**	**Total SO_x**	**Urban VOC**	**Urban CO**	**Urban NO_x**	**Urban PM10**	**Urban SO_x**
	(Btu per mile traveled)			**(grams per mile traveled)**				**(grams per mile traveled)**					**(grams per mile traveled)**				
SI ICEV – Reformulated gasoline (30-ppm sulfur content, 5.7% ethanol from corn by volume)																	
WtW Total	6,738	6,523	5,616	492	0.688	0.043	519	0.245	3.544	0.304	0.116	0.132	0.126	2.159	0.066	0.028	0.040
Feedstock	5.2%	5.2%	1.6%	6.4%	71.6%	1.5%	8.1%	7.3%	1.7%	47.3%	14.7%	35.7%	0.9%	0.1%	4.7%	0.7%	2.3%
Fuel	18.3%	18.7%	9.9%	18.7%	16.7%	17.0%	18.6%	29.3%	1.3%	37.8%	58.6%	59.4%	22.4%	0.9%	52.9%	29.5%	87.6%
Vehicle	76.5%	76.2%	88.5%	74.9%	11.8%	81.6%	73.3%	63.4%	96.9%	14.8%	26.8%	4.9%	76.7%	99.0%	42.4%	69.8%	10.1%
CIDI ICEV – Low-sulfur diesel (15-ppm sulfur content)																	
WtW Total	5,374	5,352	4,760	432	0.491	0.021	449	0.099	3.516	0.262	0.078	0.095	0.049	2.154	0.071	0.025	0.028
Feedstock	5.5%	5.3%	1.6%	6.1%	83.5%	2.4%	7.8%	15.1%	1.4%	45.7%	18.1%	41.6%	1.9%	0.1%	3.6%	0.6%	2.8%
Fuel	14.6%	14.5%	8.2%	13.6%	13.6%	4.4%	13.4%	23.2%	0.8%	27.5%	42.3%	55.7%	19.9%	0.6%	35.4%	23.3%	91.4%
Vehicle	79.9%	80.2%	90.2%	80.3%	2.9%	93.2%	78.7%	61.7%	97.8%	26.7%	39.6%	2.8%	78.2%	99.3%	61.0%	76.1%	5.8%
SI ICE HEV – Reformulated gasoline (30-ppm sulfur content, 5.7% ethanol from corn by volume)																	
WtW Total	4,813	4,659	4,012	351	0.514	0.041	375	0.197	3.513	0.230	0.089	0.094	0.103	2.153	0.055	0.024	0.029
Feedstock	5.2%	5.2%	1.6%	6.4%	68.3%	1.1%	8.0%	6.5%	1.2%	44.7%	13.5%	35.7%	0.7%	0.1%	4.0%	0.6%	2.3%
Fuel	18.3%	18.7%	9.9%	18.7%	15.9%	12.8%	18.4%	26.0%	1.0%	35.7%	54.1%	59.4%	19.4%	0.6%	45.3%	24.3%	87.6%
Vehicle	76.5%	76.2%	88.5%	74.9%	15.7%	86.1%	73.6%	67.5%	97.8%	19.6%	32.3%	4.9%	79.8%	99.3%	50.7%	75.1%	10.1%
CIDI ICE HEV – Low-sulfur diesel (15-ppm sulfur content)																	
WtW Total	4,031	4,014	3,570	324	0.372	0.021	338	0.089	3.497	0.214	0.064	0.071	0.046	2.150	0.064	0.023	0.021
Feedstock	5.5%	5.3%	1.6%	6.1%	82.7%	1.9%	7.8%	12.5%	1.1%	42.0%	16.5%	41.6%	1.5%	0.1%	3.0%	0.5%	2.8%
Fuel	14.6%	14.5%	8.2%	13.6%	13.5%	3.3%	13.4%	19.2%	0.6%	25.3%	38.6%	55.7%	15.8%	0.5%	29.4%	19.6%	91.4%
Vehicle	79.9%	80.2%	90.2%	80.3%	3.8%	94.8%	78.8%	68.2%	98.3%	32.7%	44.9%	2.8%	82.7%	99.5%	67.6%	79.9%	5.8%
SI ICE PHEV – Reformulated gasoline (30-ppm sulfur content, 5.7% ethanol from corn by volume) and electricity (from U.S. average mix)																	
WtW Total	3,770	3,560	2,414	290	0.426	0.027	308	0.126	2.244	0.211	0.170	0.137	0.064	1.370	0.038	0.020	0.021
Feedstock	4.9%	5.0%	2.0%	5.6%	76.1%	1.7%	7.5%	9.9%	1.3%	36.7%	63.6%	19.3%	0.8%	0.1%	4.1%	0.5%	2.5%
Fuel	37.1%	35.8%	10.7%	40.6%	11.8%	16.0%	39.1%	24.9%	1.3%	49.7%	21.5%	78.7%	19.0%	0.7%	48.9%	20.3%	89.4%
Vehicle	58.0%	59.2%	87.3%	53.8%	12.1%	82.3%	53.4%	65.2%	97.4%	13.6%	14.8%	2.0%	80.3%	99.2%	47.0%	79.1%	8.1%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	**Fossil Energy**	**Petrol. Energy**	**CO_2**	**CH_4**	**N_2O**	**GHGs**	**Total VOC**	**Total CO**	**Total NO_x**	**Total PM10**	**Total SO_x**	**Urban VOC**	**Urban CO**	**Urban NO_x**	**Urban PM10**	**Urban SO_x**
	(Btu per mile traveled)			**(grams per mile traveled)**				**(grams per mile traveled)**					**(grams per mile traveled)**				
SI ICE PHEV – Reformulated gasoline (30-ppm sulfur content, 5.7% ethanol from corn by volume) and electricity (from high renewables mix)																	
WtW Total	3,239	2,756	2,382	208	0.308	0.026	222	0.120	2.232	0.138	0.060	0.055	0.063	1.369	0.034	0.019	0.017
Feedstock	4.5%	5.0%	1.6%	6.2%	67.7%	1.1%	7.8%	6.3%	1.2%	44.0%	11.1%	35.5%	0.7%	0.1%	3.9%	0.4%	2.2%
Fuel	28.0%	18.5%	9.9%	18.5%	15.5%	12.1%	18.2%	25.3%	0.9%	35.2%	47.0%	59.6%	18.8%	0.6%	43.7%	18.0%	87.7%
Vehicle	67.5%	76.5%	88.5%	75.2%	16.7%	86.9%	74.0%	68.4%	97.9%	20.8%	41.9%	5.0%	80.5%	99.3%	52.5%	81.7%	10.1%
CIDI ICE PHEV – Low-sulfur diesel (15-ppm sulfur content) and electricity (from U.S. average mix)																	
WtW Total	3,325	3,196	2,170	276	0.340	0.015	287	0.062	2.235	0.203	0.156	0.123	0.029	1.362	0.033	0.016	0.005
Feedstock	5.0%	5.0%	2.1%	5.3%	88.1%	2.9%	7.3%	18.7%	1.2%	34.6%	69.1%	19.5%	1.5%	0.1%	4.3%	0.6%	9.3%
Fuel	37.0%	34.6%	9.1%	38.2%	9.3%	11.3%	37.0%	18.3%	1.0%	43.5%	14.6%	79.5%	15.4%	0.1%	11.4%	3.5%	76.7%
Vehicle	58.0%	60.3%	88.9%	56.5%	2.6%	85.8%	55.6%	62.9%	97.9%	21.9%	16.2%	1.0%	83.1%	99.9%	84.4%	95.9%	14.0%
CIDI ICE PHEV – Low-sulfur diesel (15-ppm sulfur content) and electricity (from high renewables mix)																	
WtW Total	2,796	2,395	2,137	193	0.222	0.013	202	0.056	2.222	0.130	0.046	0.042	0.029	1.361	0.029	0.016	0.001
Feedstock	4.6%	5.1%	1.6%	5.9%	82.7%	1.8%	7.6%	12.0%	1.0%	41.1%	12.9%	41.4%	1.4%	0.1%	4.0%	0.4%	31.1%
Fuel	26.4%	14.4%	8.2%	13.5%	13.3%	3.2%	13.2%	18.4%	0.6%	24.7%	31.8%	55.8%	15.0%	0.0%	0.0%	0.0%	0.0%
Vehicle	69.0%	80.5%	90.2%	80.6%	4.0%	95.0%	79.2%	69.6%	98.4%	34.2%	55.3%	2.8%	83.6%	99.9%	96.0%	99.6%	68.9%
SI ICEV – Liquefied petroleum gas (70% from natural gas plant liquids, 30% from petroleum)																	
WtW Total	5,797	5,788	1,685	418	0.666	0.036	443	0.108	2.116	0.181	0.039	0.039	0.056	1.286	0.036	0.015	0.005
Feedstock	5.8%	5.7%	2.5%	6.5%	82.1%	1.3%	8.8%	6.4%	1.9%	42.5%	19.2%	64.1%	0.7%	0.1%	3.8%	0.6%	9.7%
Fuel	5.3%	5.3%	5.7%	5.2%	4.5%	1.2%	5.1%	18.9%	0.7%	32.6%	21.7%	35.9%	9.3%	0.2%	19.0%	7.0%	90.3%
Vehicle	88.9%	89.0%	91.8%	88.3%	13.4%	97.5%	86.1%	74.7%	97.4%	24.9%	59.1%	0.0%	90.0%	99.7%	77.2%	92.5%	0.0%
SI ICEV – Compressed natural gas (from North American natural gas)																	
WtW Total	6,037	5,989	35	376	1.713	0.019	417	0.086	2.178	0.284	0.070	0.049	0.052	1.359	0.179	0.016	0.003
Feedstock	6.5%	6.5%	63.1%	7.5%	70.8%	2.6%	12.9%	5.7%	1.7%	23.2%	6.3%	33.2%	1.7%	0.2%	3.2%	1.0%	11.2%
Fuel	8.1%	7.4%	36.9%	10.6%	5.5%	4.1%	10.1%	8.7%	3.6%	60.9%	60.8%	63.5%	10.0%	5.5%	81.2%	7.8%	55.1%
Vehicle	85.4%	86.0%	0.0%	81.9%	23.6%	93.4%	77.1%	85.6%	94.7%	15.9%	32.9%	3.3%	88.3%	94.4%	15.6%	91.2%	33.7%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
SI ICEV – Compressed natural gas (from non-North American natural gas)																	
WtW Total	6,686	6,635	70	416	2.100	0.020	466	0.091	2.195	0.434	0.077	0.096	0.051	1.358	0.178	0.016	0.003
Feedstock	15.6%	15.6%	81.5%	16.4%	76.2%	7.1%	22.0%	11.4%	2.5%	49.8%	14.6%	66.1%	1.3%	0.1%	2.5%	1.1%	17.3%
Fuel	7.3%	6.7%	18.5%	9.6%	4.5%	3.9%	9.0%	8.1%	3.6%	39.8%	55.4%	32.3%	10.0%	5.5%	81.8%	7.8%	51.3%
Vehicle	77.1%	77.7%	0.0%	74.0%	19.3%	89.1%	69.0%	80.5%	93.9%	10.4%	30.0%	1.7%	88.7%	94.4%	15.8%	91.1%	31.4%
H2 FCV – Gaseous hydrogen (from steam methane reforming of North American Natural Gas)																	
WtW Total	3,470	3,403	43	224	0.373	0.001	232	0.005	0.032	0.107	0.084	0.052	0.000	0.002	0.010	0.014	0.003
Feedstock	4.0%	4.0%	21.3%	3.6%	65.0%	14.4%	5.7%	17.9%	40.2%	19.2%	1.7%	3.4%	11.9%	7.0%	2.7%	0.1%	4.5%
Fuel	32.8%	31.5%	78.7%	96.4%	35.0%	85.6%	94.3%	82.1%	59.8%	80.8%	73.4%	96.6%	88.1%	93.0%	97.3%	3.4%	95.5%
Vehicle	63.2%	64.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.9%	0.0%	0.0%	0.0%	0.0%	96.4%	0.0%
H2 FCV – Gaseous hydrogen (from steam methane reforming of non-North American Natural Gas)																	
WtW Total	3,834	3,765	62	249	0.740	0.002	265	0.009	0.043	0.192	0.088	0.082	0.000	0.002	0.007	0.013	0.002
Feedstock	11.1%	11.3%	38.7%	11.4%	72.1%	33.5%	15.0%	43.3%	50.1%	45.7%	5.1%	32.6%	44.4%	15.6%	9.5%	0.4%	10.7%
Fuel	31.7%	30.5%	61.3%	88.6%	27.9%	66.5%	85.0%	56.7%	49.9%	54.3%	71.1%	67.4%	55.6%	84.4%	90.5%	2.5%	89.3%
Vehicle	57.2%	58.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	23.8%	0.0%	0.0%	0.0%	0.0%	97.1%	0.0%
H2 FCV – Liquid hydrogen (from steam methane reforming of North American Natural Gas)																	
WtW Total	4,714	4,711	35	292	0.431	0.003	302	0.005	0.048	0.087	0.031	0.016	0.000	0.002	0.002	0.013	0.000
Feedstock	3.1%	3.0%	27.8%	3.9%	58.7%	6.1%	5.5%	18.7%	28.3%	24.4%	4.9%	42.7%	13.0%	9.9%	12.4%	0.2%	100.0%
Fuel	50.4%	50.4%	72.2%	96.1%	41.3%	93.9%	94.5%	81.3%	71.7%	75.6%	27.3%	57.3%	87.0%	90.1%	87.6%	1.0%	0.0%
Vehicle	46.5%	46.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	67.9%	0.0%	0.0%	0.0%	0.0%	98.9%	0.0%
H2 FCV – Liquid hydrogen (from steam methane reforming of non-North American Natural Gas)																	
WtW Total	4,770	4,767	51	300	0.440	0.003	310	0.007	0.052	0.192	0.032	0.039	0.000	0.002	0.002	0.013	0.000
Feedstock	3.1%	3.1%	19.4%	3.9%	59.5%	6.1%	5.6%	15.0%	26.7%	11.5%	4.9%	18.3%	13.5%	10.9%	13.0%	0.2%	100.0%
Fuel	50.9%	50.9%	80.6%	96.1%	40.5%	93.9%	94.4%	85.0%	73.3%	88.5%	29.8%	81.7%	86.5%	89.1%	87.0%	0.9%	0.0%
Vehicle	46.0%	46.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	65.4%	0.0%	0.0%	0.0%	0.0%	98.9%	0.0%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
H2 FC PHEV – Gaseous hydrogen (from steam methane reforming of North American Natural Gas) and electricity (from the U.S. average mix)																	
WtW Total	2,919	2,761	58	211	0.333	0.002	219	0.009	0.031	0.134	0.165	0.111	0.000	0.002	0.010	0.013	0.006
Feedstock	4.0%	4.1%	28.9%	3.5%	76.9%	13.7%	5.9%	61.0%	35.9%	21.1%	62.0%	6.7%	20.1%	8.2%	4.0%	0.3%	3.7%
Fuel	52.6%	49.9%	71.1%	96.5%	23.1%	86.3%	94.1%	39.0%	64.1%	78.9%	26.5%	93.3%	79.9%	91.8%	96.0%	6.7%	96.3%
Vehicle	43.5%	45.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.5%	0.0%	0.0%	0.0%	0.0%	93.0%	0.0%
H2 FC PHEV – Gaseous hydrogen (from steam methane reforming of North American Natural Gas) and electricity (from the high renewables mix)																	
WtW Total	2,856	2,629	53	199	0.313	0.002	206	0.008	0.031	0.126	0.152	0.101	0.000	0.002	0.009	0.013	0.005
Feedstock	3.9%	4.1%	30.2%	3.5%	77.0%	18.8%	5.9%	60.6%	35.3%	21.4%	61.2%	6.7%	20.8%	8.6%	3.9%	0.3%	3.7%
Fuel	51.7%	47.6%	69.8%	96.5%	23.0%	81.2%	94.1%	39.4%	64.7%	78.6%	26.3%	93.3%	79.2%	91.4%	96.1%	5.9%	96.3%
Vehicle	44.4%	48.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.4%	0.0%	0.0%	0.0%	0.0%	93.8%	0.0%
H2 FC PHEV – Gaseous hydrogen (from steam methane reforming of non-North American Natural Gas) and electricity (from the U.S. average mix)																	
WtW Total	3,129	2,971	68	226	0.545	0.002	238	0.011	0.037	0.183	0.167	0.128	0.000	0.002	0.008	0.013	0.005
Feedstock	9.0%	9.4%	36.9%	8.5%	77.8%	21.5%	11.9%	64.5%	43.1%	36.6%	62.2%	17.1%	34.3%	12.9%	7.8%	0.5%	5.1%
Fuel	50.4%	47.9%	63.1%	91.5%	22.2%	78.5%	88.1%	35.5%	56.9%	63.4%	26.5%	82.9%	65.7%	87.1%	92.2%	6.2%	94.9%
Vehicle	40.5%	42.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.3%	0.0%	0.0%	0.0%	0.0%	93.4%	0.0%
H2 FC PHEV – Gaseous hydrogen (from steam methane reforming of non-North American Natural Gas) and electricity (from the high renewables mix)																	
WtW Total	3,066	2,837	64	213	0.525	0.003	225	0.010	0.037	0.175	0.154	0.119	0.000	0.002	0.008	0.012	0.005
Feedstock	9.1%	9.6%	38.4%	8.7%	78.0%	25.5%	12.2%	64.3%	42.8%	37.6%	61.5%	17.9%	37.1%	13.8%	7.9%	0.4%	5.2%
Fuel	49.6%	45.6%	61.6%	91.3%	22.0%	74.5%	87.8%	35.7%	57.2%	62.4%	26.2%	82.1%	62.9%	86.2%	92.1%	5.4%	94.8%
Vehicle	41.4%	44.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.3%	0.0%	0.0%	0.0%	0.0%	94.2%	0.0%
H2 FC PHEV – Liquid hydrogen (from steam methane reforming of North American Natural Gas) and electricity (from the U.S. average mix)																	
WtW Total	3,638	3,518	52	251	0.366	0.003	259	0.009	0.040	0.123	0.134	0.090	0.000	0.002	0.005	0.012	0.004
Feedstock	3.3%	3.3%	32.1%	3.7%	71.5%	9.4%	5.8%	61.3%	28.6%	23.4%	76.3%	11.6%	20.8%	9.8%	7.5%	0.3%	5.3%
Fuel	61.9%	60.6%	67.9%	96.3%	28.5%	90.6%	94.2%	38.7%	71.4%	76.6%	9.6%	88.4%	79.2%	90.2%	92.5%	5.3%	94.7%
Vehicle	34.9%	36.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.1%	0.0%	0.0%	0.0%	0.0%	94.4%	0.0%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
H2 FC PHEV – Liquid hydrogen (from steam methane reforming of North American Natural Gas) and electricity (from the high renewables mix)																	
WtW Total	3,590	3,416	49	241	0.351	0.003	250	0.008	0.040	0.117	0.124	0.083	0.000	0.002	0.005	0.012	0.004
Feedstock	3.2%	3.3%	33.2%	3.6%	70.4%	13.5%	5.6%	59.8%	28.1%	23.6%	75.0%	11.8%	20.9%	10.2%	7.5%	0.3%	5.4%
Fuel	61.5%	59.6%	66.8%	96.4%	29.6%	86.5%	94.4%	40.2%	71.9%	76.4%	9.7%	88.2%	79.1%	89.8%	92.5%	4.6%	94.6%
Vehicle	35.3%	37.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.2%	0.0%	0.0%	0.0%	0.0%	95.1%	0.0%
H2 FC PHEV – Liquid hydrogen (from steam methane reforming of non-North American Natural Gas) and electricity (from the U.S. average mix)																	
WtW Total	3,670	3,550	62	255	0.372	0.003	264	0.010	0.043	0.183	0.134	0.103	0.000	0.002	0.005	0.012	0.004
Feedstock	3.3%	3.4%	27.4%	3.7%	71.8%	9.3%	5.8%	56.1%	27.5%	15.9%	75.9%	10.2%	21.0%	10.3%	7.6%	0.3%	5.3%
Fuel	62.1%	60.9%	72.6%	96.3%	28.2%	90.7%	94.2%	43.9%	72.5%	84.1%	10.0%	89.8%	79.0%	89.7%	92.4%	5.2%	94.7%
Vehicle	34.6%	35.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.1%	0.0%	0.0%	0.0%	0.0%	94.4%	0.0%
H2 FC PHEV – Liquid hydrogen (from steam methane reforming of non-North American Natural Gas) and electricity (from the high renewables mix)																	
WtW Total	3,622	3,449	59	246	0.356	0.003	254	0.009	0.042	0.177	0.125	0.096	0.000	0.002	0.005	0.012	0.004
Feedstock	3.3%	3.3%	28.1%	3.7%	70.7%	13.3%	5.7%	54.5%	27.0%	15.8%	74.6%	10.3%	21.1%	10.7%	7.6%	0.3%	5.4%
Fuel	61.7%	59.9%	71.9%	96.3%	29.3%	86.7%	94.3%	45.5%	73.0%	84.2%	10.2%	89.7%	78.9%	89.3%	92.4%	4.6%	94.6%
Vehicle	35.0%	36.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.2%	0.0%	0.0%	0.0%	0.0%	95.1%	0.0%
SI ICEV – E85 (85% ethanol from corn and 15% reformulated gasoline by volume) – credits for co-products allocated using Market Value Method																	
WtW Total	7,927	3,821	1,598	292	0.640	0.172	359	0.313	3.687	0.600	0.480	0.136	0.109	2.149	0.050	0.020	0.012
Feedstock	11.2%	22.7%	20.7%	-81.7%	34.6%	77.8%	-53.6%	9.1%	3.8%	61.6%	68.2%	33.8%	1.5%	0.3%	22.3%	4.7%	26.3%
Fuel	23.8%	49.2%	12.1%	48.5%	46.4%	1.9%	41.5%	41.4%	3.0%	30.9%	26.2%	65.2%	9.9%	0.2%	22.1%	9.3%	66.5%
Vehicle	65.0%	28.1%	67.2%	133.2%	19.0%	20.3%	112.1%	49.5%	93.2%	7.5%	5.6%	1.0%	88.7%	99.5%	55.6%	85.9%	7.2%
SI ICEV – E85 (85% ethanol from corn and 15% reformulated gasoline by volume) – credits for co-products allocated using Displacement Method																	
WtW Total	8,361	4,264	1,507	325	0.715	0.168	392	0.257	3.678	0.543	0.520	0.152	0.108	2.147	0.047	0.021	0.009
Feedstock	6.9%	13.2%	15.6%	-80.5%	23.6%	76.7%	-55.7%	-27.1%	2.4%	50.8%	60.6%	21.5%	0.5%	0.2%	15.6%	0.2%	5.9%
Fuel	31.5%	61.6%	13.1%	60.8%	59.4%	2.4%	53.0%	66.8%	4.2%	40.9%	34.2%	77.6%	10.0%	0.3%	24.8%	7.6%	85.0%
Vehicle	61.6%	25.2%	71.3%	119.7%	17.0%	20.9%	102.7%	60.3%	93.4%	8.3%	5.2%	0.9%	89.5%	99.5%	59.6%	92.2%	9.2%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
SI ICEV – E85 (85% cellulosic ethanol from herbaceous biomass [switchgrass] and 15% reformulated gasoline by volume) – credits for co-products allocated using Energy Content Method																	
WtW Total	8,731	1,866	1,429	68	0.318	0.150	121	0.271	3.532	0.388	0.118	0.060	0.108	2.145	0.041	0.019	0.010
Feedstock	6.7%	30.5%	14.9%	-425%	54.0%	59.4%	-212%	5.6%	1.8%	63.5%	16.8%	54.7%	0.8%	0.2%	8.9%	2.6%	15.2%
Fuel	34.3%	11.9%	9.9%	-47.7%	7.8%	17.3%	-19.7%	37.3%	0.9%	24.9%	60.3%	43.0%	9.7%	0.2%	22.7%	8.9%	76.1%
Vehicle	59.0%	57.5%	75.2%	572.4%	38.2%	23.3%	331.9%	57.1%	97.3%	11.6%	22.9%	2.3%	89.6%	99.7%	68.5%	88.5%	8.7%
SI ICEV – E85 (85% cellulosic ethanol from herbaceous biomass [switchgrass] and 15% reformulated gasoline by volume) – credits for co-products allocated using Displacement Method																	
WtW Total	7,127	-140	1,383	-92	0.024	0.153	-44	0.259	3.515	0.231	-0.165	-0.149	0.107	2.142	0.031	0.017	-0.001
Feedstock	8.2%	-406.6%	15.4%	314.6%	727%	58.4%	587.3%	5.8%	1.8%	107%	-12%	-22%	0.8%	0.2%	11.7%	2.8%	-142%
Fuel	19.5%	1273.4%	6.9%	209.5%	-1142%	19%	431.2%	34.3%	0.4%	-26%	128%	123%	9.4%	0.1%	-2.1%	0.8%	322.4%
Vehicle	72.3%	-766.8%	77.7%	-424.1%	515%	22.9%	-919%	59.9%	97.8%	19.5%	-16%	-0.9%	89.8%	99.8%	90.4%	96.3%	-80.8%
SI ICEV – E85 (85% cellulosic ethanol from herbaceous biomass [waste] and 15% reformulated gasoline by volume) – credits for co-products allocated using Energy Content Method																	
WtW Total	8,400	1,544	1,342	64	0.270	0.061	89	0.265	3.501	0.240	0.106	0.044	0.107	2.143	0.039	0.019	0.009
Feedstock	2.0%	10.6%	7.7%	-460%	41.2%	0.5%	-329%	2.5%	0.7%	32.7%	4.8%	29.0%	0.4%	0.0%	2.7%	0.7%	6.4%
Fuel	36.7%	19.8%	12.3%	-49.1%	13.8%	42.5%	-25.4%	38.9%	1.2%	48.6%	69.8%	67.9%	9.8%	0.2%	25.2%	9.4%	84.2%
Vehicle	61.4%	69.6%	80.1%	608.8%	45.0%	57.0%	454.2%	58.6%	98.1%	18.7%	25.4%	3.1%	89.9%	99.7%	72.1%	89.9%	9.4%
SI ICEV – E85 (85% cellulosic ethanol from herbaceous biomass [waste] and 15% reformulated gasoline by volume) – credits for co-products allocated using Displacement Method																	
WtW Total	6,713	-543	1,274	-97	-0.037	0.064	-78	0.250	3.476	0.065	-0.180	-0.169	0.107	2.140	0.028	0.017	-0.002
Feedstock	2.5%	-30.2%	8.1%	302.8%	-303%	0.5%	374.2%	2.7%	0.7%	122%	-2.8%	-7.5%	0.4%	0.0%	3.8%	0.8%	-29.8%
Fuel	20.7%	327.8%	7.6%	198.2%	734%	45.1%	242.7%	35.4%	0.4%	-91%	118%	108%	9.4%	0.1%	-2.3%	0.9%	173.3%
Vehicle	76.8%	-197.6%	84.3%	-401%	-331%	54.4%	-517%	61.9%	98.8%	69.7%	-15%	-0.8%	90.2%	99.9%	98.5%	98.4%	-43.5%
SI ICEV – E85 (85% cellulosic ethanol from woody biomass [hybrid poplar] and 15% reformulated gasoline by volume) – credits for co-products allocated using Energy Content Method																	
WtW Total	9,049	1,642	1,408	87	0.282	0.071	115	0.270	3.524	0.305	0.113	0.130	0.107	2.143	0.039	0.019	0.009
Feedstock	3.7%	20.2%	15.7%	-393%	45.9%	9.7%	-293%	5.5%	1.6%	59.0%	11.6%	21.9%	0.6%	0.1%	5.0%	2.0%	13.5%
Fuel	39.3%	14.4%	8.0%	44.8%	11.0%	40.9%	42.3%	37.0%	0.9%	26.3%	64.5%	77.1%	9.6%	0.2%	23.9%	8.8%	77.6%
Vehicle	56.9%	65.4%	76.3%	448.1%	43.1%	49.5%	350.9%	57.4%	97.5%	14.8%	23.9%	1.0%	89.7%	99.7%	71.1%	89.2%	9.0%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
SI ICEV – E85 (85% cellulosic ethanol from woody biomass [hybrid poplar] and 15% reformulated gasoline by volume) – credits for co-products allocated using Displacement Method																	
WtW Total	6,005	-2,490	1,305	-362	-0.326	0.077	-345	0.244	3.485	-0.019	-0.457	-0.251	0.107	2.137	0.019	0.016	-0.012
Feedstock	5.6%	-13.3%	17.0%	94.2%	-39.6%	8.9%	97.5%	6.1%	1.7%	-958%	-2.9%	-11.4%	0.6%	0.1%	10.5%	2.4%	-10.3%
Fuel	8.5%	156.5%	0.7%	113.3%	177%	46.0%	119.2%	30.4%	-0.2%	1298%	109%	112%	9.0%	-0.1%	-59.7%	-9.4%	117.1%
Vehicle	85.8%	-43.1%	82.3%	-107.5%	-37.2%	45.2%	-116.7%	63.5%	98.6%	-240%	-5.9%	-0.5%	90.3%	100.0%	149.2%	107.1%	-6.9%
SI ICEV – E85 (85% cellulosic ethanol from woody biomass [waste] and 15% reformulated gasoline by volume) – credits for co-products allocated using Energy Content Method																	
WtW Total	8,940	1,535	1,334	118	0.270	0.064	144	0.265	3.503	0.238	0.108	0.120	0.107	2.143	0.039	0.019	0.009
Feedstock	1.9%	11.0%	8.1%	-248%	41.3%	0.5%	-202%	2.6%	0.7%	34.2%	4.8%	10.7%	0.4%	0.0%	2.8%	1.1%	6.7%
Fuel	40.4%	19.0%	11.4%	19.1%	13.7%	45.1%	22.5%	38.8%	1.2%	46.9%	70.1%	88.2%	9.7%	0.2%	25.0%	9.2%	83.9%
Vehicle	57.6%	70.0%	80.5%	328.8%	45.0%	54.4%	279.6%	58.6%	98.1%	18.9%	25.1%	1.1%	89.9%	99.7%	72.1%	89.7%	9.4%
SI ICEV – E85 (85% cellulosic ethanol from woody biomass [waste] and 15% reformulated gasoline by volume) – credits for co-products allocated using Displacement Method																	
WtW Total	5,843	-2,648	1,194	-314	-0.343	0.072	-299	0.236	3.454	-0.115	-0.465	-0.267	0.106	2.137	0.018	0.016	-0.013
Feedstock	3.0%	-6.4%	9.1%	93.2%	-32.5%	0.5%	97.1%	2.9%	0.7%	-71.1%	-1.1%	-4.8%	0.4%	0.0%	6.1%	1.3%	-4.6%
Fuel	8.8%	147.0%	1.0%	130.4%	168%	50.7%	137.3%	31.5%	-0.2%	210%	107%	105%	9.1%	-0.1%	-62.4%	-9.5%	111.2%
Vehicle	88.2%	-40.6%	90.0%	-123.7%	-35.4%	48.8%	-134.4%	65.6%	99.5%	-39.2%	-5.8%	-0.5%	90.6%	100.0%	156.3%	108.2%	-6.5%
SI ICE PHEV – E85 (85% ethanol from corn and 15% RFG by volume) and electricity (from U.S. average mix) – credits for co-products allocated using Displacement Method																	
WtW Total	4,458	2,602	671	219	0.446	0.080	254	0.131	2.301	0.312	0.341	0.145	0.056	1.365	0.030	0.018	0.008
Feedstock	6.3%	10.5%	16.5%	-49.3%	41.9%	68.5%	-34.4%	-18.8%	1.8%	42.8%	68.9%	14.0%	0.5%	0.1%	11.2%	0.7%	4.6%
Fuel	44.7%	72.0%	15.6%	74.2%	40.7%	3.7%	66.0%	56.2%	3.2%	48.1%	24.4%	85.7%	8.4%	0.2%	29.1%	7.6%	91.0%
Vehicle	49.0%	17.5%	67.8%	75.1%	17.3%	27.8%	68.4%	62.5%	95.0%	9.2%	6.7%	0.4%	91.1%	99.6%	59.7%	91.7%	4.5%
SI ICE PHEV – E85 (85% ethanol from corn and 15% RFG by volume) and electricity (from high renewables mix) – credits for co-products allocated using Displacement Method																	
WtW Total	3,930	1,802	639	137	0.328	0.079	168	0.125	2.289	0.240	0.231	0.064	0.056	1.364	0.026	0.015	0.004
Feedstock	6.2%	13.0%	15.6%	-81.2%	21.6%	69.5%	-55.2%	-23.6%	1.6%	48.8%	57.6%	21.1%	0.4%	0.1%	12.0%	0.8%	5.5%
Fuel	38.2%	61.7%	13.1%	61.0%	54.9%	2.2%	52.2%	58.1%	2.9%	39.3%	32.5%	78.0%	8.2%	0.2%	19.1%	5.2%	85.3%
Vehicle	55.6%	25.3%	71.3%	120.3%	23.6%	28.3%	103.0%	65.5%	95.5%	11.9%	9.8%	0.9%	91.4%	99.7%	68.9%	94.0%	9.2%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
SI ICE PHEV – E85 (85% cellulosic ethanol from herbaceous biomass [switchgrass] and 15% RFG by volume) and electricity (from U.S. average mix) – Energy Content Method																	
WtW Total	4,615	1,585	638	110	0.277	0.073	139	0.137	2.239	0.246	0.170	0.106	0.056	1.364	0.027	0.016	0.008
Feedstock	6.1%	17.4%	15.9%	-108.3%	67.8%	52.4%	-74.8%	8.2%	1.4%	49.1%	64.3%	19.1%	0.7%	0.1%	6.5%	1.5%	9.3%
Fuel	46.5%	53.9%	12.7%	59.0%	4.3%	16.9%	49.9%	32.0%	1.0%	39.3%	22.3%	80.4%	8.1%	0.2%	28.1%	8.3%	86.4%
Vehicle	47.4%	28.7%	71.3%	149.2%	27.9%	30.7%	124.9%	59.8%	97.6%	11.6%	13.3%	0.5%	91.2%	99.7%	65.4%	90.2%	4.3%
SI ICE PHEV – E85 (85% cellulosic ethanol from herbaceous biomass [switchgrass] and 15% RFG by volume) and electricity (from high renewables mix) – Energy Content Method																	
WtW Total	4,565	1,479	635	101	0.262	0.073	129	0.137	2.239	0.240	0.160	0.098	0.056	1.364	0.027	0.016	0.008
Feedstock	6.1%	18.0%	15.9%	-119.8%	66.0%	52.5%	-81.7%	7.9%	1.4%	49.7%	62.5%	19.5%	0.7%	0.1%	6.4%	1.5%	9.3%
Fuel	46.1%	51.2%	12.4%	56.0%	4.5%	16.9%	46.9%	32.1%	1.0%	38.3%	23.4%	79.9%	8.1%	0.2%	26.9%	7.8%	86.1%
Vehicle	47.9%	30.8%	71.7%	163.9%	29.5%	30.6%	134.8%	60.0%	97.6%	11.9%	14.2%	0.6%	91.3%	99.7%	66.7%	90.7%	4.6%
SI ICE PHEV – E85 (85% cellulosic ethanol from herbaceous biomass [waste] and 15% RFG by volume) and electricity (from U.S. average mix) – Energy Content Method																	
WtW Total	4,473	1,447	601	109	0.257	0.035	125	0.134	2.226	0.183	0.165	0.099	0.056	1.363	0.026	0.016	0.008
Feedstock	2.4%	7.1%	9.1%	-111.8%	63.2%	0.5%	-94.6%	5.7%	0.6%	26.9%	62.5%	11.8%	0.4%	0.0%	2.6%	0.5%	4.8%
Fuel	48.8%	61.4%	15.1%	60.3%	6.7%	35.4%	55.9%	33.2%	1.2%	57.5%	23.8%	87.6%	8.2%	0.2%	29.9%	8.6%	90.7%
Vehicle	48.9%	31.5%	75.8%	151.5%	30.1%	64.1%	138.7%	61.1%	98.2%	15.6%	13.7%	0.6%	91.4%	99.8%	67.5%	90.9%	4.5%
SI ICE PHEV – E85 (85% cellulosic ethanol from herbaceous biomass [waste] and 15% RFG by volume) and electricity (from high renewables mix) – Energy Content Method																	
WtW Total	4,424	1,344	597	99	0.241	0.035	115	0.134	2.225	0.177	0.155	0.092	0.056	1.363	0.026	0.015	0.008
Feedstock	2.3%	7.1%	9.0%	-123.1%	61.0%	0.5%	-103.4%	5.4%	0.6%	26.9%	60.5%	11.9%	0.4%	0.0%	2.5%	0.5%	4.8%
Fuel	48.3%	59.0%	14.8%	57.1%	7.0%	35.4%	52.9%	33.3%	1.2%	56.9%	24.9%	87.5%	8.1%	0.2%	28.6%	8.1%	90.5%
Vehicle	49.4%	33.9%	76.2%	166.0%	32.0%	64.1%	150.6%	61.3%	98.2%	16.2%	14.6%	0.6%	91.5%	99.8%	68.9%	91.4%	4.7%
SI ICE PHEV – E85 (85% cellulosic ethanol from woody biomass [hybrid poplar] and 15% RFG by volume) and electricity (from U.S. average mix) – Energy Content Method																	
WtW Total	4,750	1,490	630	118	0.262	0.039	136	0.137	2.236	0.211	0.168	0.136	0.056	1.363	0.027	0.016	0.008
Feedstock	3.8%	11.8%	16.7%	-119.7%	65.0%	8.0%	-100.9%	8.2%	1.3%	43.9%	63.5%	13.6%	0.6%	0.0%	4.0%	1.0%	8.3%
Fuel	50.2%	57.7%	10.9%	80.5%	5.5%	34.8%	73.5%	31.8%	1.0%	42.6%	23.0%	86.0%	8.1%	0.2%	29.0%	8.4%	87.3%
Vehicle	46.0%	30.6%	72.3%	139.2%	29.5%	57.3%	127.5%	60.0%	97.8%	13.6%	13.5%	0.4%	91.3%	99.7%	67.0%	90.7%	4.4%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
SI ICE PHEV – E85 (85% cellulosic ethanol from woody biomass [hybrid poplar] and 15% RFG by volume) and electricity (from high renewables mix) – Energy Content Method																	
WtW Total	4,701	1,386	626	109	0.247	0.039	126	0.136	2.235	0.205	0.158	0.129	0.056	1.363	0.026	0.015	0.008
Feedstock	3.7%	12.1%	16.7%	-131.0%	62.9%	8.3%	-109.7%	7.9%	1.2%	44.5%	61.6%	13.7%	0.6%	0.0%	3.9%	0.9%	8.4%
Fuel	49.8%	55.0%	10.6%	79.5%	5.8%	34.6%	72.2%	31.8%	1.0%	41.5%	24.0%	85.8%	8.0%	0.2%	27.8%	7.9%	86.9%
Vehicle	46.5%	32.9%	72.7%	151.5%	31.3%	57.0%	137.5%	60.3%	97.8%	14.0%	14.4%	0.4%	91.4%	99.8%	68.3%	91.2%	4.6%
SI ICE PHEV – E85 (85% cellulosic ethanol from woody biomass [waste] and 15% RFG by volume) and electricity (from U.S. average mix) – Energy Content Method																	
WtW Total	4,702	1,443	598	132	0.257	0.036	148	0.134	2.227	0.183	0.166	0.132	0.056	1.363	0.026	0.016	0.008
Feedstock	2.3%	7.3%	9.5%	-92.1%	63.3%	0.5%	-79.5%	5.7%	0.6%	27.7%	62.3%	9.0%	0.4%	0.0%	2.6%	0.6%	4.9%
Fuel	51.2%	61.1%	14.3%	67.1%	6.6%	37.6%	62.7%	33.2%	1.2%	56.6%	24.0%	90.6%	8.2%	0.2%	29.8%	8.5%	90.6%
Vehicle	46.5%	31.6%	76.2%	125.0%	30.1%	61.8%	116.8%	61.1%	98.2%	15.7%	13.7%	0.4%	91.5%	99.8%	67.6%	90.9%	4.5%
SI ICE PHEV – E85 (85% cellulosic ethanol from woody biomass [waste] and 15% RFG by volume) and electricity (from high renewables mix) – Energy Content Method																	
WtW Total	4,653	1,340	594	122	0.242	0.036	139	0.134	2.226	0.176	0.156	0.124	0.056	1.363	0.026	0.015	0.008
Feedstock	2.2%	7.3%	9.4%	-99.7%	61.1%	0.5%	-85.8%	5.4%	0.6%	27.8%	60.3%	8.9%	0.4%	0.0%	2.5%	0.5%	4.9%
Fuel	50.8%	58.7%	13.9%	65.0%	6.9%	37.7%	60.7%	33.3%	1.2%	55.9%	25.1%	90.7%	8.1%	0.2%	28.5%	8.0%	90.3%
Vehicle	47.0%	34.0%	76.7%	134.7%	32.0%	61.8%	125.1%	61.3%	98.2%	16.3%	14.6%	0.5%	91.5%	99.8%	69.0%	91.4%	4.7%
BEV – Electricity (from U.S. average mix)																	
WtW Total	2,506	2,180	89	225	0.321	0.004	233	0.016	0.035	0.199	0.319	0.222	0.000	0.003	0.011	0.013	0.011
Feedstock	3.9%	4.3%	34.8%	3.4%	98.8%	13.3%	6.2%	82.8%	29.5%	22.7%	87.3%	7.9%	27.1%	9.8%	5.9%	0.6%	3.4%
Fuel	96.1%	95.7%	65.2%	96.6%	1.2%	86.7%	93.8%	17.2%	70.5%	77.3%	6.8%	92.1%	72.9%	90.2%	94.1%	11.9%	96.6%
Vehicle	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%	0.0%	0.0%	0.0%	0.0%	87.5%	0.0%
BEV – Electricity (from high renewables mix)																	
WtW Total	2,376	1,905	80	199	0.280	0.004	206	0.015	0.034	0.182	0.292	0.202	0.000	0.002	0.009	0.013	0.010
Feedstock	3.7%	4.3%	36.8%	3.1%	98.8%	21.3%	6.0%	82.3%	27.6%	22.9%	86.7%	7.8%	28.7%	10.5%	5.7%	0.6%	3.3%
Fuel	96.3%	95.7%	63.2%	96.9%	1.2%	78.7%	94.0%	17.7%	72.4%	77.1%	6.8%	92.2%	71.3%	89.5%	94.3%	10.4%	96.7%
Vehicle	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.5%	0.0%	0.0%	0.0%	0.0%	89.1%	0.0%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
H2 FCV – Gaseous hydrogen (from electrolysis of water at fueling stations with electricity from U.S. average mix)																	
WtW Total	7,823	6,804	278	701	1.002	0.012	726	0.050	0.108	0.621	0.957	0.692	0.001	0.009	0.034	0.018	0.035
Feedstock	72.0%	72.0%	72.0%	100.0%	100%	100%	100.0%	100%	100%	100%	97.8%	100%	100.0%	100.0%	100.0%	28.6%	100.0%
Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Vehicle	28.0%	28.0%	28.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	0.0%	0.0%	0.0%	0.0%	71.4%	0.0%
H2 FCV – Gaseous hydrogen (from electrolysis of water at fueling stations with electricity from high renewables mix)																	
WtW Total	7,417	5,947	251	621	0.873	0.014	643	0.046	0.105	0.568	0.874	0.630	0.001	0.008	0.030	0.018	0.032
Feedstock	70.4%	70.4%	70.4%	100.0%	100%	100%	100.0%	100%	100%	100%	97.6%	100%	100.0%	100.0%	100.0%	25.6%	100.0%
Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Vehicle	29.6%	29.6%	29.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	0.0%	0.0%	0.0%	0.0%	74.4%	0.0%
H2 FCV – Liquid hydrogen (from electrolysis of water at fueling stations with electricity from U.S. average mix)																	
WtW Total	9,958	8,662	353	892	1.276	0.016	924	0.064	0.138	0.790	1.211	0.880	0.002	0.012	0.043	0.020	0.045
Feedstock	78.0%	78.0%	78.0%	100.0%	100%	100%	100.0%	100%	100%	100%	98.3%	100%	100.0%	100.0%	100.0%	33.8%	100.0%
Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Vehicle	22.0%	22.0%	22.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	0.0%	0.0%	0.0%	0.0%	66.2%	0.0%
H2 FCV – Liquid hydrogen (from electrolysis of water at fueling stations with electricity from high renewables mix)																	
WtW Total	9,442	7,570	319	790	1.111	0.017	819	0.059	0.133	0.722	1.107	0.802	0.001	0.010	0.038	0.019	0.041
Feedstock	76.8%	76.8%	76.8%	100.0%	100%	100%	100.0%	100%	100%	100%	98.1%	100%	100.0%	100.0%	100.0%	30.4%	100.0%
Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Vehicle	23.2%	23.2%	23.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	69.6%	0.0%
H2 FC PHEV – Gaseous hydrogen (from electrolysis of water at fueling stations with electricity from U.S. average mix) and electricity (from U.S. average mix)																	
WtW Total	5,436	4,728	193	487	0.697	0.009	504	0.035	0.075	0.431	0.669	0.481	0.001	0.007	0.024	0.015	0.025
Feedstock	60.6%	60.6%	89.1%	83.8%	99.8%	85.5%	84.3%	97.1%	88.2%	87.0%	96.0%	84.6%	87.8%	84.9%	84.2%	19.8%	83.8%
Fuel	16.1%	16.1%	10.9%	16.2%	0.2%	14.5%	15.7%	2.9%	11.8%	13.0%	1.2%	15.4%	12.2%	15.1%	15.8%	3.8%	16.2%
Vehicle	23.3%	23.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	0.0%	0.0%	0.0%	0.0%	76.4%	0.0%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
H2 FC PHEV – Gaseous hydrogen (from electrolysis of water at fueling stations with electricity from high renewables mix) and electricity (from high renewables mix)																	
WtW Total	5,154	4,132	174	431	0.606	0.010	447	0.032	0.073	0.394	0.612	0.438	0.001	0.005	0.021	0.015	0.022
Feedstock	59.2%	59.3%	89.4%	83.7%	99.8%	86.8%	84.2%	97.0%	87.9%	87.1%	95.7%	84.5%	88.0%	85.0%	84.2%	17.6%	83.8%
Fuel	16.2%	16.1%	10.6%	16.3%	0.2%	13.2%	15.8%	3.0%	12.1%	12.9%	1.2%	15.5%	12.0%	15.0%	15.8%	3.3%	16.2%
Vehicle	24.6%	24.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	0.0%	0.0%	0.0%	0.0%	79.0%	0.0%
H2 FC PHEV – Liquid hydrogen (from electrolysis of water at fueling stations with electricity from U.S. average mix) and electricity (from U.S. average mix)																	
WtW Total	6,671	5,803	237	598	0.855	0.011	619	0.043	0.092	0.529	0.816	0.590	0.001	0.008	0.029	0.016	0.030
Feedstock	67.9%	67.9%	91.1%	86.8%	99.8%	88.1%	87.2%	97.6%	90.4%	89.4%	96.7%	87.4%	90.0%	87.7%	87.1%	23.9%	86.8%
Fuel	13.1%	13.1%	8.9%	13.2%	0.2%	11.9%	12.8%	2.4%	9.6%	10.6%	1.0%	12.6%	10.0%	12.3%	12.9%	3.6%	13.2%
Vehicle	19.0%	19.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	0.0%	0.0%	0.0%	0.0%	72.5%	0.0%
H2 FC PHEV – Liquid hydrogen (from electrolysis of water at fueling stations with electricity from high renewables mix) and electricity (from high renewables mix)																	
WtW Total	6,325	5,071	214	529	0.744	0.012	549	0.039	0.089	0.484	0.746	0.537	0.001	0.007	0.025	0.016	0.027
Feedstock	66.8%	66.9%	91.4%	86.8%	99.8%	89.2%	87.1%	97.6%	90.1%	89.5%	96.5%	87.4%	90.3%	87.8%	87.1%	21.4%	86.8%
Fuel	13.2%	13.1%	8.6%	13.2%	0.2%	10.8%	12.9%	2.4%	9.9%	10.5%	1.0%	12.6%	9.7%	12.2%	12.9%	3.2%	13.2%
Vehicle	20.1%	20.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%	0.0%	0.0%	0.0%	0.0%	75.4%	0.0%
BEV – Electricity (from remote stranded renewables via HVDC transmission lines)																	
WtW Total	1,063	0	0	0	0.000	0.000	0	0.000	0.000	0.000	0.019	0.000	0.000	0.000	0.000	0.012	0.000
Feedstock	0.0%	-	-	-	-	-	-	-	-	-	0.0%	-	-	-	-	0.0%	-
Fuel	100.0%	-	-	-	-	-	-	-	-	-	0.0%	-	-	-	-	0.0%	-
Vehicle	0.0%	-	-	-	-	-	-	-	-	-	100%	-	-	-	-	100.0%	-
BEV – Electricity (from remote stranded renewables via hydrogen pipeline and high temperature fuel cell power plant) – credits for co-products allocated using Energy Content Method																	
WtW Total	1,735	29	6	3	0.004	0.000	3	0.000	0.002	0.017	0.021	0.003	0.000	0.000	0.003	0.012	0.000
Feedstock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel	100.0%	100.0%	100.0%	100.0%	100%	100%	100%	100%	100%	100%	10.8%	100%	100.0%	100.0%	100.0%	0.3%	100.0%
Vehicle	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	89.2%	0.0%	0.0%	0.0%	0.0%	99.7%	0.0%

Table A-1: Well-to-Wheels Results (*continued*)

	Total Energy	Fossil Energy	Petrol. Energy	CO_2	CH_4	N_2O	GHGs	Total VOC	Total CO	Total NO_x	Total PM10	Total SO_x	Urban VOC	Urban CO	Urban NO_x	Urban PM10	Urban SO_x
	(Btu per mile traveled)			(grams per mile traveled)				(grams per mile traveled)					(grams per mile traveled)				
BEV – Electricity (from remote stranded renewables via hydrogen pipeline and high temperature fuel cell power plant) – credits for co-products allocated using Displacement Method																	
WtW Total	1,566	-551	7	-32	-0.057	-0.001	-34	-0.001	-0.024	0.011	0.020	0.003	0.000	-0.006	0.001	0.011	0.000
Feedstock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel	100.0%	100.0%	100.0%	100.0%	100%	100%	100.0%	100%	100%	100%	4.7%	100%	100.0%	100.0%	100.0%	-5.0%	100.0%
Vehicle	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	95.3%	0.0%	0.0%	0.0%	0.0%	105.0%	0.0%
H2 FCV – Gaseous hydrogen (from central electrolysis of water with electricity from remote stranded renewables)																	
WtW Total	3,460	438	35	44	0.062	0.001	46	0.003	0.011	0.089	0.078	0.047	0.000	0.000	0.002	0.013	0.002
Feedstock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel	36.6%	100.0%	100.0%	100.0%	100%	100%	100.0%	100%	100%	100%	73.1%	100%	100.0%	100.0%	100.0%	2.0%	100.0%
Vehicle	63.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	26.9%	0.0%	0.0%	0.0%	0.0%	98.0%	0.0%
H2 FCV – Liquid hydrogen (from central electrolysis of water with electricity from remote stranded renewables)																	
WtW Total	5,336	1,922	98	199	0.279	0.004	206	0.015	0.037	0.231	0.290	0.204	0.000	0.002	0.009	0.014	0.010
Feedstock	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel	58.9%	100.0%	100.0%	100.0%	100%	100%	100.0%	100%	100%	100%	92.8%	100%	100.0%	100.0%	100.0%	9.5%	100.0%
Vehicle	41.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.2%	0.0%	0.0%	0.0%	0.0%	90.5%	0.0%
H2 FC PHEV – Gaseous hydrogen (from central electrolysis of water with electricity from remote stranded renewables) and electricity (from U.S. average mix)																	
WtW Total	2,928	1,079	54	110	0.158	0.002	114	0.008	0.019	0.126	0.164	0.110	0.000	0.001	0.005	0.013	0.005
Feedstock	1.2%	3.2%	21.0%	2.5%	73.2%	9.9%	4.6%	60.4%	19.4%	13.0%	61.7%	5.8%	21.0%	7.6%	4.5%	0.2%	2.6%
Fuel	55.5%	96.8%	79.0%	97.5%	26.8%	90.1%	95.4%	39.6%	80.6%	87.0%	26.8%	94.2%	79.0%	92.4%	95.5%	6.0%	97.4%
Vehicle	43.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.5%	0.0%	0.0%	0.0%	0.0%	93.7%	0.0%
H2 FC PHEV – Gaseous hydrogen (from central electrolysis of water with electricity from remote stranded renewables) and electricity (from high renewables mix)																	
WtW Total	2,865	947	50	98	0.138	0.002	102	0.007	0.019	0.118	0.151	0.100	0.000	0.001	0.004	0.012	0.005
Feedstock	1.1%	3.1%	21.7%	2.3%	73.0%	15.8%	4.4%	59.8%	18.1%	12.9%	60.9%	5.7%	22.3%	8.2%	4.4%	0.2%	2.6%
Fuel	54.6%	96.9%	78.3%	97.7%	27.0%	84.2%	95.6%	40.2%	81.9%	87.1%	26.6%	94.3%	77.7%	91.8%	95.6%	5.2%	97.4%
Vehicle	44.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.5%	0.0%	0.0%	0.0%	0.0%	94.6%	0.0%