U.S. DEPARTMENT OF ENERGY | Energy Efficiency & Renewable Energy

TRANSPORTATION ENERGY FUTURES SERIES

FUELS

Projected Biomass Utilization for Fuels and Power in a Mature Market

TRANSPORTATION ENERGY FUTURES SERIES:

Projected Biomass Utilization for Fuels and Power in a Mature Market

A Study Sponsored by
U.S. Department of Energy
Office of Energy Efficiency and Renewable Energy

March 2013

Prepared by

NATIONAL RENEWABLE ENERGY LABORATORY
Golden, Colorado 80401-3305
managed by
Alliance for Sustainable Energy, LLC
for the
U.S. DEPARTMENT OF ENERGY
under contract DC-A36-08GO28308

About the Transportation Energy Futures Project

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

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

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

Contract Nos.
DC-A36-08GO28308 and DE-AC02-06CH11357

AVAILABILITY

This report is available electronically at http://www.osti.gov/bridge

Available for a processing fee to
U.S. Department of Energy and its
contractors, in paper form, from:

U.S. Department of Energy
Office of Scientific and Technical
Information
P.O. Box 62
Oak Ridge, TN 37831-0062
phone: 865.576.8401
fax: 865.576.5728
email: mreports@adonis.osti

Available for sale to the public,
in paper form, from:

U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
phone: 800.553.6847
fax: 703.605.6900
email: orders@ntis.fedworld.gov
online ordering:
http://www.ntis.gov/help/ordermethods.aspx

CITATION

Please cite as follows:

Ruth, M.; Mai, T.; Newes, E.; Aden, A.; Warner, E.; Uriarte, C; Inman, D.; Simpkins, T.; Argo, A. (March 2013). *Projected Biomass Utilization for Fuels and Power in a Mature Market.* Transportation Energy Futures Series. Prepared for the U.S. Department of Energy by National Renewable Energy Laboratory, Golden, CO. DOE/GO-102013-3707. 153 pp.

Report Contributors and Roles

National Renewable Energy Laboratory

Mark Ruth	Lead and primary author
Trieu Mai	Model developer
Emily Newes	Data analyst and contributing author
Andy Aden	Biomass data expert
Ethan Warner	Life cycle analyst
Caroline Uriarte	Data analyst
Daniel Inman	Data analyst
Travis Simpkins	Model developer
Andrew Argo	Biomass data expert

Acknowledgments

We are grateful to colleagues who reviewed portions or the entirety of this report in draft form, including:

Ingrid Ardjosoediro, Commodity Expert and Agricultural Economist, Global Policy Analysis Division, Foreign Agriculture Service, U.S. Department of Agriculture (USDA)

Marilyn Buford, National Program Leader, Silviculture Research, Forest Management Sciences, Forest Service, USDA

Vince Camobreco, Environmental Protection Specialist, Transportation and Climate Division, Office of Transportation and Air Quality (OTAQ), U.S. Environmental Protection Agency (EPA)

Nita Contreras, Staff Assistant, Rural Development, USDA

Marina Denicoff, Economist, AMS Transportation Services Division, USDA

Garvin Heath, Senior Scientist, Strategic Life Cycle Analysis, Energy Analysis Center, National Renewable Energy Laboratory

Dr. Mike Ladisch, Director, Laboratory of Renewable Resources Engineering Professor, Agricultural and Biological Engineering, Mascoma Corporation, Purdue University

Sara Ohrel, Economist, Climate Change Division, Office of Atmospheric Programs, EPA

Dr. Gerard Ostheimer, Science Advisor, Office of Global Analysis, Foreign Agriculture Service, USDA

Dr. Michael Shelby, Chief Economist, Transportation and Climate Division, OTAQ, EPA

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

Many analysts and managers at the U.S. Department of Energy played important roles in sponsoring this work and providing valuable guidance. From the Office of Energy Efficiency and Renewable Energy, Sam Baldwin and Carla Frisch provided leadership in conceptualizing the project. A core team of analysts collaborated closely with the national lab team throughout implementation of the project. These included:

Jacob Ward and Philip Patterson (now retired), Vehicle Technologies Office

Tien Nguyen and Fred Joseck, Fuel Cell Technologies Office

Zia Haq, Kristen Johnson, and Alicia Lindauer-Thompson, Bioenergy Technologies Office

The national lab project management team consisted of Austin Brown, Project Lead, and Laura Vimmerstedt, Project Manager (from the National Renewable Energy Laboratory); and Tom Stephens, Argonne Lead (from Argonne National Laboratory). Data analysts, life cycle assessment analysts, managers, contract administrators, administrative staff, and editors at both labs offered their dedication and support to this effort.

Table of Contents

List of Figures

List of Tables

Acronyms

AEO	Annual Energy Outlook
BASE	biomass allocation and supply equilibrium
BD	biodiesel
BEAP	Biomass Environmental Assessment Program
BLM	Biomass Logistics Model
BSM	Biomass Scenario Model
BT2	Updated Billion Ton Study
Btu	British thermal unit
bu	bushel
CCS	carbon capture and storage
CD	conventional diesel
CG	conventional gasoline
CNG	compressed natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CSP	concentrating solar power
DME	dimethyl ether
DOE	U.S. Department of Energy
dt	dry ton
E85	85% ethanol in gasoline
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
EWITS	Eastern Wind Integration and Transmission
FAPRI	Food and Agricultural Policy Research Institute
FT	Fischer-Tropsch
gal	gallon
GCAM	Global Climate Assessment Model
gde	gallon diesel equivalent
GDP	gross domestic product
GET	Global Energy Transition
gge	gallon gasoline equivalent
GHG	greenhouse gases
GREET	Greenhouse Gases, Regulated Emissions and Energy Use in Transportation
IGCC	integrated gasification combined cycle
LCOE	levelized cost of energy
LHV	lower heating value
LNG	liquefied natural gas
MARKAL	Market Allocation Model
MTG	methane to gasoline
NASS	National Agricultural Statistics Service
NG	natural gas
NG[-]CC	natural gas combined cycle
NG[-]CT	natural gas combustion turbines
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PHEV	plug-in hybrid electric vehicle
PV	photovoltaic

quad	quadrillion Btu
R&D	research and development
RBAEF	Role of Biomass in America's Energy Future
RD	renewable diesel
RD&D	research, development, and demonstration
RE	renewable energy
ReEDS	Regional Energy Deployment System
REF	Renewable Electricity Futures
SEDS	Stochastic Energy Deployment Systems (computer model)
SRWC	short rotation woody crops
TEF	Transportation Energy Futures
USDA	U.S. Department of Agriculture
WTT	well-to-tank
WTW	well-to-wheel(s)

Executive Summary

The U.S. biomass resource can be used several ways that provide domestic, renewable energy to users. Understanding the capacity of the biomass resource, its potential in energy markets, and the most economic utilization of biomass is important in policy development and project selection. This study analyzed the potential for biomass within markets and the competition between them. The study found that biomass has the potential to compete well in the jet fuel and gasoline markets, penetration of biomass in markets is likely to be limited by the size of the resource, and that biomass is most cost effectively used for fuels instead of power in mature markets unless carbon capture and sequestration is available and the cost of carbon is around $80/metric ton CO_2e.

Biomass Utilization Issues

Biomass is a limited resource with many competing uses. Its allocation for fuel, power, and products depends upon characteristics of each of these markets, their interactions, and policies affecting these markets. In order to better understand competition for biomass among markets and the potential for biofuel as a market-scale alternative to petroleum-based fuels, the Transportation Energy Futures (TEF) study created a unique modeling tool to analyze the impact of these multiple demand areas.

There are compelling reasons for use of biomass in each of these three markets:

- Fuel: Biomass is the primary renewable resource that can be used to generate liquid fuels for today's vehicles and infrastructure.
- Power: Technology is currently available to enable co-firing with coal, reducing the carbon intensity of baseload electricity and providing one of the few renewable dispatchable options.
- Products: Mixtures of chemicals with carbon-hydrogen-oxygen bonds such as those found in biomass are too valuable to burn.

Federal policy and activities have supported both biofuels and biopower. Relevant policies include the renewable fuels standard, the renewables portfolio standard, the clean energy standard, and many state and regional greenhouse gas (GHG) policies. Goals for biofuel policies include reduction in petroleum and, especially, petroleum imports to increase energy security. Other goals for biofuel policies focus on environmental and economic concerns, GHG emissions reduction, and diversification of agricultural products. Goals for biopower policies include displacement of coal for environmental concerns and GHG reduction. In the past two decades, the U.S. Department of Energy's research and development (R&D)

Key Findings

- Biofuels are likely to be able to compete successfully with petroleum-based fuels, particularly in the jet fuel and gasoline markets, if R&D is successful and petroleum product prices are as high as the Energy Information Administration projects.
- Penetration of biofuels is constrained by the size of the potential biomass resource.
- Biomass is most cost effectively used for fuels instead of power in mature energy markets unless carbon capture and sequestration is available and the cost of carbon is around $80/metric ton CO_2e.
- Pyrolysis-based biofuels are more cost competitive than other biofuels and show the greatest potential for market penetration.
- Markets with a cost of carbon drive up demand for biomass in the transportation sector, increasing the price of biomass and making biopower less competitive with other electricity generation alternatives.

has addressed both biofuels and biopower. In addition, U.S. Environmental Protection Agency deployment activities have included biopower, especially where it can address environmental issues, as well as applications for niche biofuels.

Many models only consider biomass in either the power or fuels market, but not both. If one looks at the results of such models, the biomass availability and utilization could easily be double-counted because competition from the other sector is not considered. Such double-counting might lead to unwarranted conclusions and decisions; thus, studies that consider demand from multiple sectors are needed.

Allocation of resource between biopower and biofuels, as well as across different fuels markets, is of keen interest in understanding how this energy resource might contribute to the national goals of reduced petroleum use and GHG emissions. While some existing literature explores this issue, and a few existing modeling tools have been developed to analyze it, a detailed market equilibrium analysis of the issues had not been performed as of 2012. As a result, researchers determined one would be useful in exploration of the implications of diverse scenarios where biomass can be used for power and multiple fuels.

BASE – A Market Equilibrium Model Developed for this Project

A market at equilibrium is one where the quantity supplied and that demanded are equivalent and prices are set by the market such that the supply meets the demand. Market equilibrium analysis is useful, because it indicates how a mature commodity market is likely to perform. Thus, results of market expansion models can be compared to market equilibrium analysis to ensure that driving forces in the market expansion models are headed toward equilibrium. Market equilibrium models do not provide insights into interim technology development or the merits of policy options.

The research team developed a simple market equilibrium modeling tool specifically for the TEF project. The Biomass Allocation and Supply Equilibrium (BASE) model is a market equilibrium model for biomass supplies and markets. The model includes domestic supply curves for the following four categories of lignocellulosic biomass resources: forest residues, short-rotation woody crops (SRWC), agricultural residues, and switchgrass (the general name used throughout this report for all grassy energy crops). The BASE model also includes corn for ethanol (non-cellulosic/conventional production) and butanol production, soybeans for biodiesel, and algae for diesel.

In addition, five domestic markets for biomass-based energy are included: electricity, gasoline, diesel, jet fuel, and bunker fuel. Multiple fuel and feedstock options are supplied in the model for each fuel market. Well-to-wheel (WTW) GHG emissions and petroleum use are included in the model to determine carbon costs and report the effects of petroleum use. Market sizes are set and kept constant because market elasticity is poorly understood, resulting in the effects of substitutes (e.g., natural gas for natural gas vehicles) on fuel prices not being sufficiently understood to include in this model. Imports and exports are not included in the BASE model because of a lack of information.

Advanced biofuels pathways are projected to reduce GHG emissions and petroleum use well below conventional technology. The differences between the biofuels are small when compared to the differences between each biofuel and the conventional technology. To fully understand the effects on the biomass markets, the model was run with multiple parameter values including various carbon costs.

Input data for the BASE model were collected from publicly available sources and include projections of biomass supply cost curves, biomass harvesting and transport costs, biomass conversion costs, electricity costs from other sources, fuel transport and dispensing costs, and well-to-wheel greenhouse gas emissions and petroleum use. Levelized costs for each fuel and electricity are calculated based on the inputs and include a cost of carbon for some scenarios. The 2050 levelized cost projections of cellulosic biofuels indicate that they are cost-competitive with gasoline at feedstock costs of up to $160/dry ton. On the other hand, 2050 levelized cost projections of biopower indicate that it is not cost competitive with feedstock costs of over $40/dry ton.

Biofuels Can Attain Considerable Market Share but are Constrained by Resource Size

One key conclusion of this study is that biomass can attain market share in the transportation sector, particularly the diesel and jet fuel markets. That conclusion is based on mature market conditions with the default biomass feedstock, transport, and conversion assumptions and the business as usual projections for market sizes and conventional fuel prices. In a hypothetical 2020 market, biofuel penetration can achieve penetration levels 15% in the gasoline market and 25% in the jet fuel market. In a scenario where the cost of carbon is high ($80/metric ton CO_2e), biofuels penetration in each market is about 5% higher than without a cost of carbon because biofuels are less carbon intensive than conventional fuels.

Note that the market allocations in this study are estimates that are dependent upon mature, balanced markets where R&D has been as successful as projected. In addition, other drivers could affect the actual markets: regulations may affect the market structure, access to capital may not be possible, markets may evolve in ways that prevent them from reaching equilibrium, and many temporal reasons may prevent the markets from nearing equilibrium (e.g., retirement rates of and/or replacement of existing stock, conservative business decisions, uncertain and changing policies, lack of achievement of plant cost and performance projections due to lack of learning, and so on).

Biomass could attain an even larger market share in the hypothetical markets if it was not resource limited. In the default scenario, the feedstock supply curves were completely depleted for some lignocellulosic feedstocks (i.e., SRWC, agricultural residues, and switchgrass). Complete utilization of feedstocks indicates that wider deployment of biofuels is warranted by the market.

Biomass Competitiveness is Limited in Power Markets

Biopower does not achieve much market share (<1%) even with a price of carbon of $80/metric ton CO_2e, unless carbon capture and storage (CCS) is available. The primary reason biopower does not penetrate is that it is more expensive than other low-carbon options for electricity generation, which compete successfully, especially in scenarios with higher costs of carbon. More optimistic biopower cost and performance assumptions do not considerably increase its market share. On the other hand, availability of CCS increases biopower penetration from essentially nothing to 2%-13% of the power market with a $40-$80/metric ton cost of carbon.

Pyrolysis-Based Fuels are Projected to be More Competitive

Among the different types of biofuels considered in this study, pyrolysis fuels (gasoline and diesel) are more cost competitive with conventional fuels than other biofuels. Thus they had the greatest market penetration when available. If R&D in pyrolysis does not succeed, biofuel penetration is much lower in the jet and diesel markets. In a scenario where the R&D on pyrolysis-based fuels failed and the fuels were not available in 2050, biofuel penetration dropped by 90% in the diesel market and by 65% in the jet fuel market.

High Costs of Carbon Drives Up Demand for Biomass for Fuels

While costs of carbon have a greater decarbonizing effect on the electricity sector compared to the fuel sector, markets with a carbon cost drive up demand for biomass in the transportation sector. Therefore, the presence of carbon costs drives up the cost of biomass and makes biopower less competitive with other power-generation options. The result is different if CCS is available for the electric sector and an $80/metric ton CO_2e cost of carbon is considered. In that case, biomass is utilized for power because of the negative carbon emissions.

Biofuel Availability Reduces Petroleum Use

A hypothetical 2020 market with biofuels has a well-to-wheels petroleum use that is 88% of one without biofuels when there is no cost of carbon. Petroleum use is further reduced to 84% of a non-biofuel market when a cost of carbon of $80/metric ton CO_2e is considered. Increased costs of carbon only have minor effects on reductions in petroleum use, because most of the biomass supply is utilized for fuel at no cost of carbon, making only small increases possible.

The bottom line is that biofuels are likely to compete successfully with petroleum-based fuels and use a large share of the potential resource—if R&D is successful and petroleum product prices are as high as the U.S. Energy Information Administration projects [Annual Energy Outlook 2011 reference case (U.S. EIA 2011)].

1. Introduction

In the Transportation Energy Futures (TEF) project, biomass[1] was identified early on as a key resource for analysis, because large quantities are potentially available and have the potential to be used for many purposes, including liquid fuels, electricity, hydrogen, and chemical products. Currently, large amounts of biomass are being utilized for energy, and much more biomass is or can be available as an energy feedstock. In 2010, 3.9 quadrillion British thermal units (Btu), or quads, of biomass were used, including lignocellulosic biomass, corn for ethanol, soybeans for biodiesel, and municipal solid waste, landfill gas, and sewage sludge, supplying 4% of the total energy consumption in the United States, and surpassing hydropower as the largest domestic source of renewable energy (DOE and EIA 2010a). In the future, approximately 16 quads of energy could be available from one billion dry short tons of lignocellulosic biomass—an estimate of the total, sustainable biomass potential in the United States (U.S. Billion Ton Update, DOE 2011).

The potential to convert a limited biomass resource to valuable products, such as liquid fuels, electricity, hydrogen, and chemicals results in questions about the best use of that resource. From a transportation viewpoint, liquid biofuels are advantageous, because they are the primary renewable option for current vehicles and aircraft. In addition, liquid biofuels can use the same or similar infrastructure that is currently in place for gasoline, diesel, bunker fuel (fuel used onboard ships), and jet fuel. From an electricity viewpoint, biomass-generated electricity is one of few dispatchable and non-variable renewable options and thus can be used for base load electricity (i.e., power that meets the 24-hour minimum demand).

Because of the number of options for utilizing biomass, the following key questions about its use were identified early in the project:

- What are the costs and implications of biomass use and allocation in transportation and other sectors?
- Will market forces allow access to biomass fuels for those sectors or transport modes that have limited alternative options to reduce their greenhouse gas (GHG) emissions? What strategies or policies might address market failures in the use of biomass, while improving the probability of meeting economy-wide GHG and oil reduction goals? How might decisions early in the market evolution drive toward different end points that may or may not be the most desirable?
- What are likely geographic distributions of bio-based fuels use under various deployment scenarios?
- How can alternative technology options (including supply chain options) enable wider use of bioenergy to reduce GHG emissions and oil use in the transportation sector?

This task addresses the first key question above by way of a micro-economic analysis of biomass markets that supply biomass to mature energy markets. The markets are assumed to approximate equilibrium—the quantity of biomass supplied and demanded are equivalent and the biomass prices are set such that the supply is sufficient to meet the demand. Mature commodity markets operate close to equilibrium, because the products are fungible and the markets are essentially "perfectly competitive." Perfectly competitive markets, often called "free markets," are markets in which there are many buyers and sellers (none of whom can influence prices) and barriers to market entry have been overcome. Free markets are not necessarily unregulated, but they are markets where regulation does not affect the competitiveness. Due to a higher level of risk, near-term markets for biomass are not expected to approach equilibrium, even

[1] In this paper, biomass refers to biological material from living or recently living organisms. Lignocellulosic biomass is from non-edible plant matter, including agricultural residues, forestry residues, woody energy crops, and herbaceous energy crops. Algae refer to the algae that are grown to generate fuels. Edible corn and soybeans are counted separately. Other analyses also include relatively small sources of biomass such as animal fats, municipal solid waste, landfill gas, and sewage sludge.

though they are growing faster than the economy. Although greater resource availability reduces barriers to entry, the elevated risk can diminish the number of investors.

By focusing on mature biomass markets, this study identifies how biomass is projected to be most economically used in the long term and the implications of that market on GHG emissions and petroleum use. That viewpoint provides value in understanding how biomass can be used in markets at equilibrium and quantifies the drivers that affect the amount of biomass used and its distribution between electricity and fuel markets. The results can be used to support research and development (R&D) target setting and project selection, by helping identify drivers that affect the potential penetration of specific technologies in a market at equilibrium. For example, if the market penetration of a given technology is supply limited, and a sensitivity on yield improvements is performed, the results of that sensitivity can indicate the yield necessary for market saturation. Therefore, efforts to improve the yield beyond that point are not necessary, because it will not increase market penetration. In addition, the model can assist in identifying policy options that drive the markets away from the desired outcome. For example, the effects on other markets of subsidies in one market can be studied.

The Biomass Allocation and Supply Equilibrium (BASE) model was developed specifically for this analysis. It includes supply curves for the following four categories of lignocellulosic biomass: forest residues, short-rotation woody crops (SRWC), agricultural residues, and switchgrass (the general name used throughout this report for all grassy energy crops). It also includes corn for ethanol and butanol production, soybeans for biodiesel, and algae for diesel. Five markets where biomass-based energy compete are also included: electricity, gasoline, diesel, jet fuel, and bunker fuel. Prices for each fuel within each market are calculated independently and model iterations solve for consistent biomass prices. Multiple fuel and feedstock options are included in the model for each fuel market with specific efficiencies defined for each feedstock-fuel combination. Sensitivity results are reported to identify how potential assumptions affect the projected market distributions.

This study does not consider how the development of near-term markets might affect long-term markets by expending capital resources on technologies that detract from equilibrium. Additional studies of market development will be necessary to determine whether current activity is on the desired track.

Section 2 highlights existing analyses of biomass markets. Issues and opportunities for additional analysis are identified. Section 3 describes the analysis methodology, BASE model, and default data used for this analysis. Section 4 reports the results from runs performed using the default data. Section 5 reports results from sensitivity runs and implications of those results. Potential future work is discussed in Section 6, and conclusions of this analysis are reported in Section 7. Additional information is provided in the appendices.

2. Other Analyses of Biomass Utilization Potential and Competition

Analyses of biomass utilization options and the potential splits between fuels, power, and other uses have been performed by many other organizations. Reviewed studies are broken into three categories: (1) competition between biomass species and how their use could affect market evolution, (2) comparison of biomass products (including fuel and electricity) on non-economic bases, and (3) competition of biomass between markets (especially fuels and electricity). Because this study focuses on potential biomass markets, the following discussion will focus more on the third category of studies.

In addition to these types of studies, many studies focus on biomass supply and its potential effects, the techno-economics of specific technologies, or effects of biomass utilization on GHG emissions. Those studies focus on capital costs, operating costs, yields, direct and indirect land use change, and many other factors. However, those studies are considered outside the scope of this paper.

The first category of studies reviewed here focuses on competition between biomass species and the potential evolution of biomass markets and land use effects. One example of that type of study (Khanna et al. 2010) defined specific value to biomass crops to estimate utilization of idle cropland and other studies performed similar feedstock cost analyses. Of the studies that focused on competition between species, some investigated competition between biomass feedstock sources in specific locales and the ability of those resources to meet specific demands. For example, one study (Sun, Li, and Hou 2011) investigated competition between biomass species for power generation and straw pulp industries in China. Its authors found that raw material competition could potentially prevent the development of multiple products. In this study, the biomass cost curves are from the BT2, which includes competition issues for the land and raw materials. The other studies were used only for comparing the biomass feedstock cost curves.

The second category of studies compares utilization options for biomass by means of non-economic criteria such as GHG emissions, efficiency, and potential miles driven per acre of biomass produced. Those that focus on GHG emissions (Wahlund, Yan, and Westermark 2004; Campbell and Block 2010; Campbell, Lobell, and Field 2009) generally find that utilization of biomass for power production has a larger effect on GHG emissions than use of lignocellulosic biomass for transportation fuel. This result is based on displacement of fossil-fuel power generation and displacement of gasoline, so it is not surprising. The studies that focus on efficiency (usually defined as mechanical work generated divided by chemical energy in the biomass) find that power production and utilization in electric vehicles is more efficient than second generation biofuel production (Ohlrogge et al. 2009). This is because more miles can be driven on biomass that is used to generate power for a battery electric vehicle than from liquid fuel generation (Humbird et al. 2011). The source of the efficiency difference is the increased efficiency of electric vehicles as compared to internal combustion engines.

Few publications report on studies in the third and most relevant category—competition for biomass between markets (especially electricity and fuel markets) on an economic basis. Instead, many of the studies are focused on developing biomass markets. Furthermore, a number of those studies and their corresponding models are not published in a way that provides insights into biomass markets and utilization. A National Renewable Energy Laboratory (NREL) study (Newes et al. 2012), however, focuses on developing a holistic understanding of the competition for biomass resources among the various end uses. The study reviewed a number of capacity expansion models, including:

- **Stochastic Energy Deployment System (SEDS)**. A stochastic, dynamic recursive capacity expansion model that treats the United States as a single region with three product options for biomass: cellulosic ethanol, electricity, and hydrogen.

- **National Energy Modeling System (NEMS)**. A multi-sector, dynamic recursive capacity expansion model used for the Government Performance and Results Act (GPRA) (GPRA Modernization Act of 2010, 2011), which models the full energy sector. As a result, it is difficult to extract an understanding of biomass markets from the resulting publications.
- **Global Change Assessment Model (GCAM)**. An integrated, partial-equilibrium, dynamic recursive capacity expansion assessment model of the global industrial and energy system. GCAM includes agriculture and land use. A description of the results from a recent analysis can be found later in this section.
- **Global Trade Analysis Project (GTAP) model**. A global general equilibrium capacity expansion model that includes ethanol from sugarcane and cereals and biodiesel from vegetable oil.
- **Targets-Image Energy Regional Model (TIMER)**. A capacity expansion model that is used as part of the Integrated Model to Assess the Global Environment (IMAGE).
- **SimBioSys**. A capacity expansion model of the bioenergy sector that minimizes the total generation cost of biofuels and biomethane to compete against gasoline, diesel, and natural gas.
- **Biomass Allocation Model**. A dynamic recursive capacity expansion model that uses linear optimization to optimize the allocation of biomass between cellulosic ethanol and co-firing in coal power plants.
- **RESolve Model.** An integrated assessment model that minimizes the cost to meet the demand of biomass for heat, fuels, and electricity.
- **Market Allocation Model (MARKAL)**. An intertemporal capacity expansion model that optimizes by selecting technologies to minimize the system-wide net present value (OpenEI). Like the NEMS, MARKAL is used for the GPRA (DOE EERE 2010), and few reports are published.

In addition, the Biomass Scenario Model (BSM) (NREL 2011) has been developed by NREL and the Biomass Program of the DOE. The BSM is a system dynamics capacity expansion model that includes all aspects of the supply chain from the growth of feedstock through harvest, collection, transport, conversion, fuel distribution, availability of vehicles that consume the fuel, and fuel consumption. The BSM is being upgraded to include competition for biomass between fuels and electricity. A stand-alone system dynamics capacity expansion model that allows for competition between the sectors has been completed (Newes et al. 2012). The model uses maximized profit subject to a production function in order to relate products to feedstocks and allows the user to choose between a simple price elasticity function and exogenous forecasts to set the demand. Model development has been completed, but rigorous testing and calibration are necessary before results will be published.

Newes et al. (2012) also linked the full BSM to a multi-regional power generation capacity expansion model—the Regional Energy Deployment System (ReEDS) (Short et al. 2011). The linkage is designed in such a way that, for each time period in ReEDS, the BSM supplies ReEDS with a total biomass supply curve and corresponding biofuels demand curve, and ReEDS estimates the amount of biomass sent to power generation. Initial results show that both the BSM and ReEDS overestimate the amount of biomass available to their respective sectors because the BSM does not include an estimate of biomass used for power and ReEDS does not include an estimate of biomass used for fuels. Combining the two models prevents either model from assuming that biomass is available for the market(s) represented by an individual model and hence the potential for double-counting biomass when looking at results from each individual model side-by-side is reduced.

A report on GCAM results regarding biomass use under low atmospheric carbon dioxide (CO_2) concentrations was published recently (Luckow et al. 2010). The investigators examined the potential role of biomass under climate policies designed to stabilize atmospheric CO_2 at two different levels—400 parts per million (ppm) and 450 ppm. They found that biopower with carbon capture and sequestration (CCS) is necessary to meet those targets, because biopower with CCS has net negative emissions. In that case, about 80% of the global biomass utilized is a feedstock for biopower with the remainder used for biofuels. If CCS technology is not successful, it is not deployed, resulting in all the biomass being used to create fuels. Therefore, nuclear power is necessary to cut emissions sufficiently to meet the targets. One issue with Luckow et al.'s analysis is that they estimated the necessary cost of carbon to achieve the targets as being extremely high. For example, to meet the 450-ppm target, they estimated that the cost of carbon needs to be over $1,000/ton of carbon in 2100 if the CCS technology is deployed and over $2,000/ton of carbon in 2100 if it is not. With prices that high, it is not surprising that biopower with sequestration is the economic winner.

Another interesting paper in this category (Grahn et al. 2007) compares two global energy models and their results. Both are linear programming-like models that solve for economic optimums over the 21st century. In the initial study, one of the models demonstrated that heat production is the most economic utility of the worldwide biomass resource, and the other demonstrated that transportation is the most feasible economic use of biomass. Interestingly, that study demonstrated methanol to be the most cost-effective biofuel. However, due to its low energy content and toxicity, it was not included in the TEF analysis. Upon harmonization of the two models, the analysis demonstrated that biomass is most cost effectively used for heat production at low costs of carbon—up to $75/metric ton of carbon = $20/metric ton CO_2e. At higher costs of carbon, the most cost-effective use of biomass is dependent upon the status of competing technologies. When the study authors assumed that renewable hydrogen is competitive for transportation, they found that the best use for biomass is heat; however, when the authors assumed high prices for renewable hydrogen, they found hydrogen production to be the best use of biomass.

Two more studies focused on competition for biomass, between electricity and fuel markets on an economic basis in developed nations. One study focused on Austria (Kalt, Kranzl, and Haas 2010) and used a scenario-development tool instead of an economic model. Scenarios with different mixes of biomass used for heat, power, and transportation fuels were developed and compared. The study concluded that, from an Austrian GHG reduction and economic efficiency standpoint, bioenergy policies should focus on promoting the use of biomass for heat and, to some extent, combined heat and power. It also found that a focus on liquid biofuels for transport has adverse effects on the development of the bioenergy sector due to increased competition for limited biomass resources. Note that small-scale biomass heating systems [< 15 kilowatts (kW)] are more common in Austria than in the United States, and that the estimated capital and operating costs are much higher than expected within this study.[2] The second study highlighted the competition for biomass between electricity and fuel markets on an economic basis in a developed nation, with a specific focus on the United States (Morrow and Balash 2008). Researchers used a linear program that is limited to one decade (2010–2020) and three technologies—co-firing with coal to produce electricity, corn ethanol, and cellulosic ethanol—but is rich in regional detail. Although the authors do not provide conclusions, they identify three primary variables that affect potential biomass utilization within the electricity and transportation sectors, including future oil prices, future CO_2 constraints [i.e., the future value of CO_2 mitigation ($/metric ton CO_2)], and the date and degree at which cellulosic ethanol process improvements materialize.

No model currently exists that uses traditional micro-economic principles to estimate market equilibrium conditions for biomass. Commodity markets have been shown to act near equilibrium when they are

[2] The estimate of capital costs for a bioethanol facility from wood or straw is €2,100/kW fuel, which converts to $4.80/annual gallon (gal) at $1.40/€. The investigators' estimate of operating costs for the same facility is €100/kW per year, which converts to $0.40/gal ethanol at $1.40/€. They have learning curves that reduce those prices by 40% by 2050, which is the end of the timeframe analyzed.

mature, and market prices are established through competition (i.e., not be a monopoly). As shown above, a number of capacity expansion models are in use; however, all those models are more focused on the dynamics of market development than on the potential market maturity. Understanding development is important but identifying the potential equilibrium state can improve policy-makers' understanding of the ultimate potential and drivers. With that knowledge, policy-makers can use capacity expansion models to test how to best approach mature markets.

Appendix A contains descriptions of many of the relevant studies.

3. Analysis Methodology and Default Data

3.1. Introduction to Analysis Methodology and the Biomass Allocation and Supply Equilibrium (BASE) Model

This analysis addresses key questions about the costs and implications of biomass use and allocation in the transportation sector and other sectors by way of a micro-economic analysis of mature biomass markets that approximate equilibrium in supplying feedstocks to energy markets. Mature commodity markets operate close to equilibrium, because the products are fungible and the markets are essentially perfectly competitive. Perfectly competitive markets are often called "free markets," and consist of many buyers and sellers, with none of the buyers or sellers having the ability to influence prices, and where barriers to market entry have been overcome.

Developed specifically for this analysis, the BASE model provides projections of equilibrium states under mature market conditions in the electricity and transportation sectors and estimates allocations in mature, free markets. By focusing on mature biomass markets, this study identifies how biomass is projected to be most economically used in the long term, and presents the implications of that market on GHG emissions and petroleum use. That viewpoint provides value in understanding how biomass would be utilized in free markets and quantifies the drivers that affect the amount of biomass used, along with its distribution between electricity and fuel markets. The results can be used to support R&D target setting and project selection, as well as to identify policy options that drive markets away from equilibrium, and resulting in increased societal costs.

The market allocations projected by BASE may not occur due to regulation, access to capital, market evolution, market equilibrium points not matching assumptions, and many temporal reasons (e.g., retirement rates of and/or replacement of existing stock, conservative business decisions, uncertain and changing policies, lack of achievement of n^{th} plant projections[3] due to lack of learning, and so on). The model does not provide snapshots of future scenarios or the incremental changes to fuel and power markets. Likewise, it is not intended to simulate near-term markets, because they are far from equilibrium due to technological immaturity, growth rate, number of investors, and nearly unlimited resources.

3.2. BASE Model Methodology and Structure

The BASE model finds an equilibrium state of the U.S. transportation and electricity sector, and based on this equilibrium state, finds the consumption and price of biomass feedstocks. The market equilibrium state is found iteratively, and relies on detailed input data of full life cycle costs. Market shares for biomass and the allocation between the different fuels and markets are determined based on levelized cost of energy (LCOE) (fuel or electricity), which accounts for many of the costs and losses that are incurred from the farm or field to the end user. These costs include feedstock costs, biomass transport and logistics costs, conversion costs, fuel transport costs, and any assumed prices to GHG emissions.

A wide variety of biomass feedstocks, fuels, and markets are represented in the BASE model. The scenario results from BASE, therefore, inform detailed and specific deployment projections for each feedstock for each fuel in each market. Table 3.1 shows a matrix of feedstocks and their possible contributions to different fuels and markets. Note that only primary products are shown in the table. Byproducts, such as electricity generated and sold to the grid in the lignocellulosic biomass to ethanol process, are not shown but are included in the cost and emissions calculations as described in Section 3.6.

[3] Projections that inherently assume that the technology is mature and thus do not include additional contingency, capital costs, and yield loss necessary for of first-of-a-kind cost estimation

Table 3.1. Biomass Feedstocks, Fuels, and Markets Represented in the BASE Model

An "X" identifies the feedstocks that can be used for each fuel and market.

Market	Electricity	Gasoline			Diesel / Jet Fuel / Bunker Fuel			
Fuel	Biopower	Ethanol	Butanol	Pyr. Gasoline	Pyr. Diesel	FT Diesel	Biodiesel	Algal Diesel
Forest Residue	X	X	X	X	X	X		
SRWC	X	X	X	X	X	X		
Agricultural Residues	X	X	X	X	X	X		
Switchgrass	X	X	X	X	X	X		
Corn		X	X					
Soybean							X	
Algae								X

Note that bunker fuel is a general term for fuel used on-board ships. This study did not include gaseous fuels from biomass, such as dimethyl ether (DME), methane, or hydrogen or other potential fuels with little ongoing R&D such as methanol. Markets for those fuels are considered negligible in this analysis because all market sizes in this analysis are based on *Annual Energy Outlook* (*AEO*) (EIA 2011a) projections and the EIA does not project substantial markets for any of those fuels.

The biomass feedstocks represented in the BASE model include forest residues, SRWC, agriculture residues, switchgrass,[4] corn, soybean, and algae. These feedstocks can be converted to biofuels or electricity. Separate end-use markets are treated in the BASE model, namely the electricity, gasoline, diesel, jet fuel, and bunker fuel markets. For biofuels, the BASE model distinguishes among a variety of feedstock/fuel combinations. Fuels include ethanol, butanol, and pyrolysis gasoline that compete in the gasoline market and pyrolysis diesel, Fischer-Tropsch (FT) diesel, and biodiesel that compete in the diesel, jet fuel, and bunker fuel markets.

The authors recognize that both feedstocks and fuels are simplified for modeling purposes. Many feedstocks were aggregated into the categories provided. In addition smaller, niche opportunities were not included. For example, diesel replacements are currently made from many renewable sources including non-soybean seed crops and rendering materials. One of the unique features of BASE is its consideration and representation of detailed biomass data that nearly encompasses the full life cycle of the end-use fuel.[5] Where applicable and available, this data is distinct for each matrix element shown in Table 3.1; through its data inputs, the BASE model distinguishes the differences between the different feedstocks and their conversion to end-use fuels at every step of this conversion pathway.

The biomass-specific data required of the BASE model are discussed in subsequent sections and include:

[4] Switchgrass is used in the BASE model to represent all herbaceous energy crops.
[5] "Fuel" in this sense refers to liquid biofuels as well as electricity from biopower generators.

- Feedstock supply curves[6] [dollars per dry ton (dt) vs. amount of dry tons]
- Feedstock demand (dt) from other sectors outside of the power or fuel sectors
- Biomass transport and logistics costs ($/dt)
- Feedstock yield [gal/dt for biofuels or million British thermal units (10^6 Btu)/dt for biopower]
- Conversion costs [$/gal for biofuels or $/megawatt-hour (MWh) for biopower]
- Heat content (Btu/gal)
- Fuel transport costs ($/gal)
- Well-to-wheel (WTW) CO_2e emission factors [gCO_2e/megajoule (MJ)] and petroleum use factors (MJ_{input}/MJ_{fuel}).

Non-biomass competing technologies are not represented in the BASE model with the same level of detail.

The BASE model uses an iterative calculation and a set of market share algorithms (referred to as logit functions) to determine the quantities of biofuel and power that are generated, and thus how much biomass is used. The demand for each market (i.e., electricity, gasoline, diesel, jet fuel, and bunker fuel) is exogenously defined. Market share algorithms are used to estimate the share of each fuel in each market based on initial estimates of fuel price. Fuel prices are then calculated based on quantities of biomass used, harvesting, conversion, and fuel transport costs. Carbon costs can also be included if desired. If the calculated fuel prices do not match those estimated initially, initial estimates are adjusted and the process is repeated until they do. The quantity of each feedstock used for fuel price calculation represents the total feedstock demand across all fuels and markets. In this way, the separate markets are coupled. For example, increased demand for switchgrass for electricity generation may drive up the price of cellulosic ethanol and therefore drive down the demand for cellulosic ethanol in the gasoline market. This reduced demand for cellulosic ethanol may open the market for corn ethanol or for conventional gasoline. By sharing the same resource and supply curve across multiple fuels and markets, the BASE model is able to account for coupling dynamics of supply and demand that will likely be more important as biomass resources are utilized in multiple markets simultaneously.

These calculated market shares and the associated demands for the biomass feedstocks and other fuel are outcomes of the model. In addition, BASE finds the equilibrium price for the biomass feedstocks—forest residue, SRWC, agriculture residue, and switchgrass—and competing energy sources—natural gas and coal—represented with supply curves. The greenhouse gas emissions implications of each modeled equilibrium scenario are also reported by BASE. The resultant GHG emissions are then broken down by each category in BASE, including by competing technologies and by the separate biomass pathways, independently. Petroleum use in each market scenario is calculated in a post-processing step.

Appendix B contains a complete description of the BASE model's methodology and structure.

[6] Corn and soybean feedstocks are not represented with supply curves due to the complicated interactions with the agriculture sector. Instead, corn and soybean costs are fixed and a range of sensitivity scenarios are evaluated. The "feedstock" costs for algal technologies are included in the conversion costs, therefore no explicit feedstock supply curves or biomass transport and logistics costs were included for algae.

3.3. Biomass Resource Supply Curves

Biomass resource potential and costs are combined in supply curves that describe the supply as a function of price. National supply curves were obtained from the updated BT2, developed by Oak Ridge National Laboratory, as well as from the 2010 U.S. and World Agricultural Outlook (FAPRI, 2010), developed by the Food and Agricultural Policy Research Institute (FAPRI). Six different feedstock categories were considered in this study, including agricultural residues, forest residues, grasses, SRWC, corn, and soybean[7]. The dataset for the first four categories were obtained from the BT2, while corn and soybean potential assessment was obtained from FAPRI.

The BT2 makes use of POLYSIS, an agricultural policy model, and data from the U.S. Department of Agriculture's (USDA's) National Agricultural Statistics Service (NASS) to estimate the supply curves for energy crops and agricultural residues up to 2030. For this analysis, data from the BT2 baseline scenario was used. That scenario assumes a continuation of the USDA 10-year forecast for the major food and forage crops, as well as a continuation in trends toward no-till and reduced cultivation. Energy crop yields assume an annual increase of 1% due to experience in planting and additional R&D. Forest residues are estimated using resource cost analysis with data from the USDA's Forest Service.[8]

Supply curves for a number of biomass types were reported in the BT2 and were aggregated into four categories of lignocellulosic biomass (shown in Table 3.2)

Table 3.2. Categorization of BT2 Biomass Types for the BASE Model

BASE Categories	BT2 Categories
Agricultural Residue	Corn stover, barley straw, rice straw, cotton residue, cotton gin trash, oat straw, orchard and vineyard prunings, rice hulls, sorghum stubble, sugarcane trash, wheat dust, wheat straw
Forest Residues	Conventional wood, treatment thinnings (other forest lands), mill residue (unused primary), mill residue (unused secondary), urban wood waste (construction and demolition), urban wood waste (municipal solid waste), integrated operations, other removal residue
Grasses	Perennial grasses, sorghum (high yield)
SRWC	Coppice and non-coppice woody crops
Unused in TEF	Animal fats and waste oils, manure

Annual estimates of production and pricing for corn and soybean through 2019 were obtained from the FAPRI. Because FAPRI only reports single cost/quantity points, supply curves for corn and soybeans were constructed for use in the model. Furthermore, as FAPRI does not provide projections beyond 2019, potential and pricing for all years after 2019 was assumed to be equivalent to those in 2019 and both 2020 and 2050 BASE supply curves were built using the FAPRI 2019 data converted to supply curves.

[7] Algae costs were fully included in the conversion costs (see Section 3.6); therefore, they were not included in this section.
[8] 2050 data were not available to meet many of the data needs for this analysis. Therefore, projections up until 2050 were made. For the four categories of lignocellulosic biomass, the 2030 projections were considered for mature technology and were not changed for use in 2050. For corn and soybeans, no projections beyond 2019 were found and the technology is mature so the 2019 projections were used for the 2020 and 2050 cases. The biomass utilization for non-fuel or electricity uses was extrapolated up until 2050; assuming constant market growth. Biomass transport using conventional schemes is considered mature so today's costs were used for both the 2020 and the 2050 cases. For biomass conversion to fuels, assumptions about the potential improvement by 2050 were made. Market sizes and prices of conventional fuels were extrapolated from 2035 based on constant changes. Electricity generation was considered mature in 2035 and the same values were used in 2050.

Figures 3.1 and 3.2 show the supply curves used in BASE for all six categories of feedstocks. Because the BT2 only projects supply curves up to 2030, the 2030 curves were used for the 2050 BASE runs. Likewise, since FAPRI only provides information through 2019, 2019 data were used for both the 2020 and 2050 supply curves. The figures include a near-vertical line at the maximum biomass allowance level, because any additional biomass would increase the price dramatically. Harvesting costs are included in the supply curves, and the costs are at the edge of the field (i.e., the crops are consolidated at a location where they are ready for shipping).

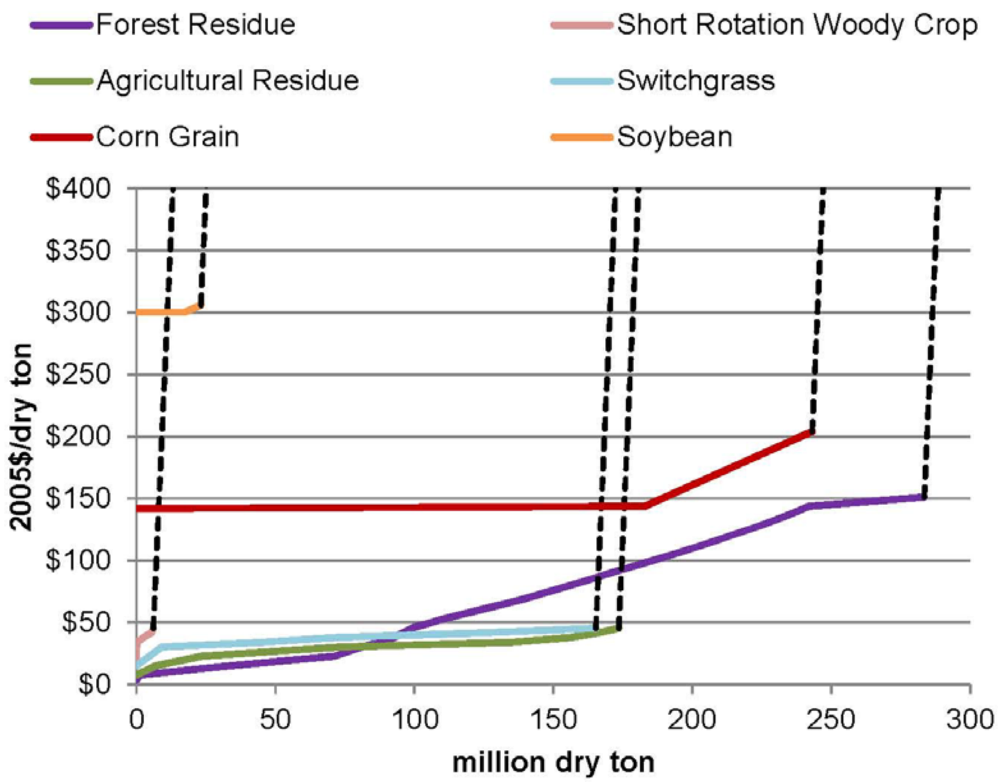


Figure 3.1. Supply curves used for the 2020 BASE runs
(Sources: DOE 2011, FAPRI 2010)

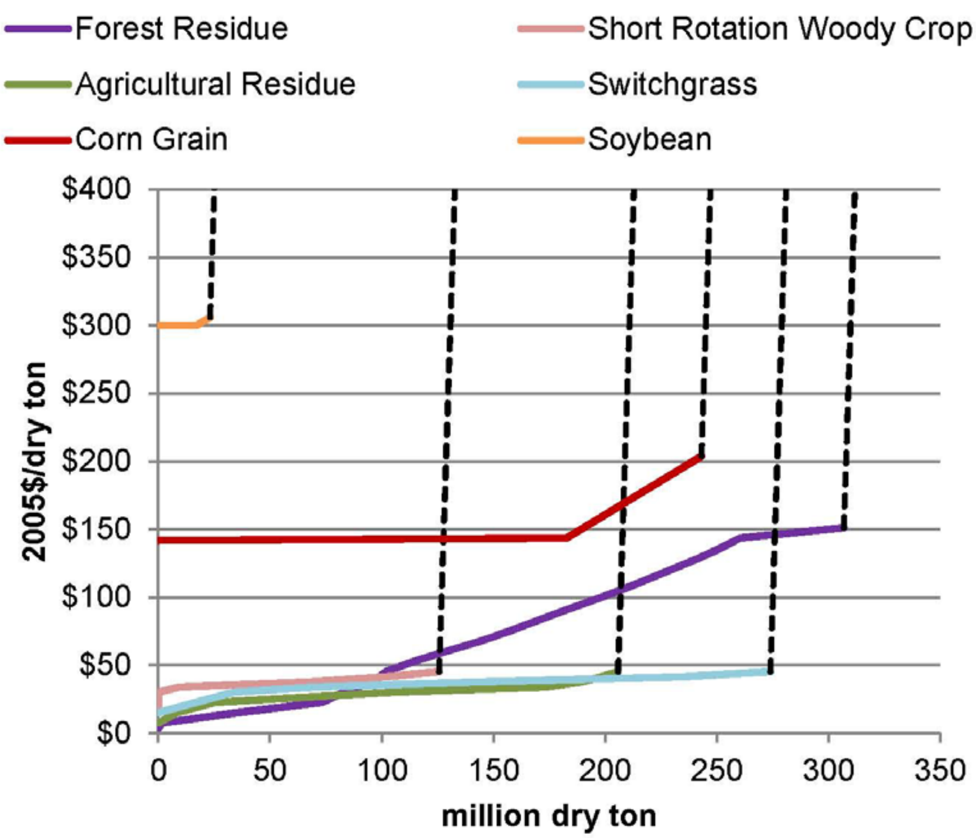


Figure 3.2. Supply curves used for the 2050 BASE runs
[Sources: EIA, U.S. EIA (2011a) (2030 data), Food and Agricultural Policy Research Institute (2010)]

Appendix C contains a complete description of the biomass resource supply curves.

3.4. Competing Uses of Biomass

Biomass can be used to produce many products beyond transportation fuels and power. In this analysis, those products are given priority thus their biomass demand is fulfilled before biomass can be used for fuels and power. In other words, other uses of biomass are likely to be able to retain profit margins while paying higher prices for biomass than fuel and electricity.

Biomass demand for food, feed, lumber, and pulp and paper were not explicitly accounted for, because those biomass demands were already excluded from the resource supply curves. Likewise, EIA's *Renewable Energy Trends in Consumption and Electricity 2008* (EIA 2010c) does not report resources necessary for pulp and paper. Competing uses considered by EIA include the following:

- Residential (including wood pellets for heat)
- Commercial (uses agriculture byproducts/crops, sludge waste, and other biomass solids, liquids and gases; black liquor and wood/wood waste solids including wood pellets for heat and liquids; and corn)
- Industrial, including:
    - Agriculture, forestry, and mining (consumes agricultural byproducts/crops)

- Chemicals and allied products (consumes other biomass liquids, sludge waste, and wood/wood waste solids)
- Apparel (consumes wood and derived fuels)
- Petroleum refining (consumes wood and derived fuels)
- Rubber and miscellaneous plastic products (consumes wood and derived fuels)
- Transportation equipment (consumes wood and derived fuels)
- Stone, clay, glass, and concrete products (consumes wood and derived fuels)
- Furniture and fixtures (consumes wood and derived fuels)
- Other non-specified, but related industries (consumes wood, including wood pellets for heat, and derived fuels and corn).

EIA's *Annual Energy Outlook 2011* estimates biomass consumption up until 2035 by residential, commercial, and industrial classification. That information was used for the BASE model and is shown in Table 3.3 (EIA 2011a).

Table 3.3. Projections from the EIA for Annual Biomass Resource Consumption by Competing Uses

Data from Annual Energy Outlook 2011 (2050 values are extrapolations), and broken down by use and feedstock type

	Million Short Tons Consumed per Year		
	2010	2020	2050
Cellulosic - Wood Residue	**40.23**	**40.68**	**41.57**
Residential	31.71	31.71	31.71
Commercial	7.58	7.58	7.58
Industrial	0.94	1.39	2.28
Cellulosic - Agricultural Residue	**1.64**	**2.18**	**3.27**
Residential	-	-	-
Commercial	0.49	0.49	0.49
Industrial	1.15	1.69	2.78
Corn Grain	**2.47**	**3.41**	**5.3**
Residential	-	-	-
Commercial	0.48	0.48	0.48
Industrial	1.99	2.93	4.82
Total	**44.3**	**46.3**	**50.1**

Appendix D contains a complete description of competing uses of biomass.

3.5. Biomass Transport Costs

To estimate total biomass costs at the plant gate, transport expenses from the field to the biorefinery are added to expenses in the biomass supply curves. In BASE, feedstocks are assumed to be supplied to the biorefinery using the conventional bale-based feedstock supply and logistics system, although research, development, and demonstration (RD&D) on more advanced systems is underway. The conventional bale-based system is representative of the current logistics system employed by most forage and hay producers in the United States. Implicit in the conventional bale-based system cost estimates are various machine efficiency, biomass yield, and material loss assumptions during harvest, transport, and storage. The conventional system was chosen for this study, because it is aligned, in terms of costs and physical/chemical composition, with the conversion stage process design reports. All transport costs in this analysis are on delivered biomass and include costs due to material lost during handling.

Costs were estimated for corn stover (as a proxy for all agricultural residues), switchgrass (as a proxy for all grasses), SRWC, forest residues, and algae using Idaho National Laboratory's Biomass Logistics Model (BLM) version 6.45 (INL 2011). Results from the BLM were analyzed and disaggregated into base costs, diesel use, electricity use, and natural gas use. Diesel, electricity, and natural gas use are multiplied by the BASE values, for each expenditure, and summed with the base costs to estimate total costs. Published expenditures were used for corn grain (Benson and Bullen 2007) and soybeans (Reinbott 2012).

Figure 3.3 displays the approximate feedstock logistics and transport costs used for each of the biomass sources. The actual costs are dependent upon the diesel, natural gas, and electricity prices within each BASE run. Note that harvest and collection costs are shown in the figure but are not included in the BASE calculations, because they are included in the biomass supply curves. Logistics and transport expenses for algae are not included, because they are inherently part of the algae growth, collection, and conversion costs discussed in the section on conversion.

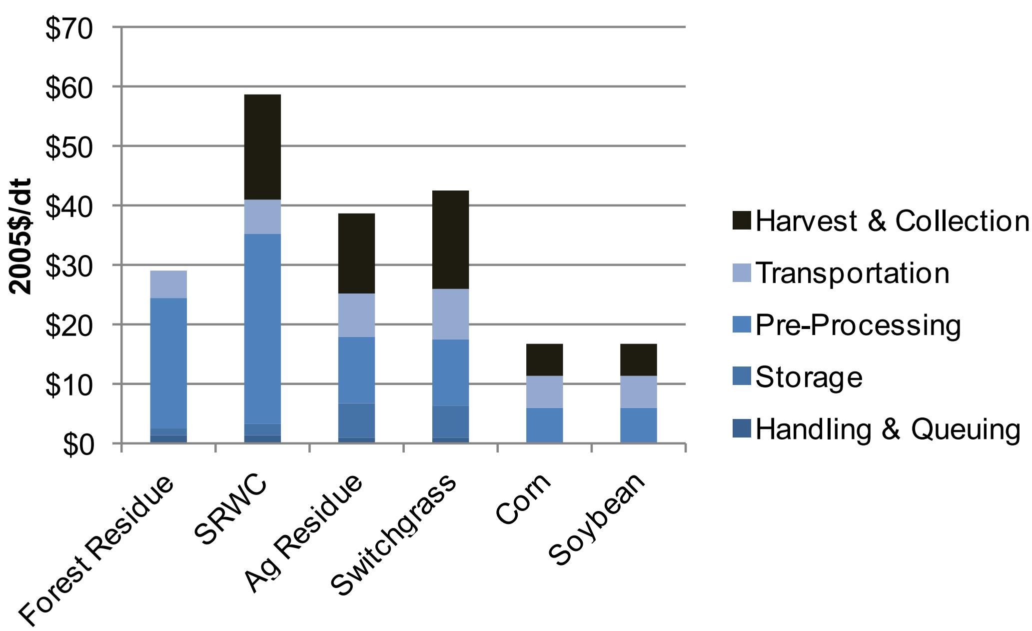


Figure 3.3. Feedstock logistic and transport costs
[Sources: Benson and Bullen (2007), Reinbott (2012), Idaho National Laboratory (INL 2011)]

Appendix E contains a complete description of biomass transport costs.

3.6. Biofuel Conversion Yields and Costs

Conversion costs and LCOE calculations were developed for the BASE model for two specific timeframes: 2020 and 2050. Eight liquid fuels and fuel pathways were examined. A summary of the fuels and feedstocks that were studied can be found in Table 3.1. In this analysis, bio-based diesel products were considered available for jet fuel and bunker fuel, without additional conversion costs. Data for each of these fuel pathways were supplied from publicly available sources when possible, and from non-public sources when otherwise not available.

The data in Table 3.4 were used to calculate the conversions in Tables 3.5 and 3.6.

Table 3.4. Data Inputs

Abbreviation	Input	Units
Feed	**Feedstock Costs**	**$/dt**
Log	Biomass Logistics and Transport Costs	$/dt
Cap	**Capital Costs**	**$/gal**
FCR	Fixed Charge Rate	-
OM	**Operating and Maintenance Costs (not including feedstock costs)**	**$/gal**
Int	Integration Costs	n/a
Byp	Byproduct Credit	$/gal
CF	Capacity Factor	n/a
HR	Heat Rate	n/a
Yield	Yield	Gal/dt
FuelTrans	Fuel Transport Costs	$/gal
CPrice	Carbon Price	$/metric ton CO_2e
CFactor	Carbon Factor	metric ton CO_2e/gal

The value for "Cap" was computed by dividing the total project investment by the plant capacity. The conversion costs and yields were constant between biomass types, because of a lack of data for each feedstock/conversion combination.

An LCOE equation was used to convert the values and a price of biomass at the plant gate to fuel prices at the plant gate. Within BASE, a single fixed charge rate of 0.132 was assumed for all fuel pathways—but not for electricity, which has a specific fixed charge rate for each conversion technology. The fixed charge rate was based upon the capital charge factor computed in NREL's most recent design reports for cellulosic ethanol (Humbird et al. 2011). Within these reports, a discounted cash flow analysis was used over an assumed 30-year plant life with a 10% discount factor. That discount rate was chosen based on the recommendation of Short, Packey, and Holt (1995).

Equation 3.1. Levelized Cost of Energy for Biofuels

$$LCOE_{fuel} = FCR \bullet Cap + OM - Byp + \frac{Log + Feed}{Yield} + FuelTrans + CPrice \bullet CFactor$$

Table 3.5. 2020 Conversion Data in 2005$

(Data sources referenced in text.)

	Cellulosic Ethanol	Cellulosic Butanol	Pyrolysis Gasoline	Pyrolysis Diesel	FT Distillate Diesel	Biodiesel from Soybeans	Corn Ethanol	Corn Butanol	Algal Diesel
Total Capital Cost (Million $)	$398	$451	$285	$285	$469	$52.9	$89.3	$308	$367
Capacity (million gal/yr)	61	25	76	76	32.3	45	45	42	10
Operating Costs ($/gal)[¥]	$0.69	$1.92	$0.94	$0.94	$1.20	$0.44	$0.47	$1.93	$3.73
Byproduct Credits ($/gal)	$0.10	$2.07	$0.00	$0.00	$0.19	$0.14	$0.30	$2.40	$0.00
Feedstock Yield (gal/dry short ton)	79.0	32.4	65.0	65.0	47.2	111[†]	118[‡]	58.8	N/A
Fuel LCOE* ($/gal)	$1.96	$3.47	$2.05	$2.05	$3.78	$3.91	$1.86	$3.36	$8.58
Year$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$

[¥] *Operating Costs only represent the costs to operate the facility and do not include the feedstock costs.*

** LCOE is calculated within BASE using feedstock costs that vary. Results reported here are for example only and use a fixed charge rate of 0.132 and feedstock cost of $40/dry short ton for lignocellulosic biomass, $383/dry short ton for soybeans [$10/bushel, 13% moisture, 60 lb (wet) per bushel], or $168/dry short ton for corn ($4/bushel, 56 lb/bushel, 15% moisture).*

[†] *Based on 2.9 gal/bushel*

[‡] *Based on 2.8 gal/bushel*

Table 3.6. 2050 Conversion Data in 2005$

(Data sources referenced in text.)

	Cellulosic Ethanol	Cellulosic Butanol	Pyrolysis Gasoline	Pyrolysis Diesel	FT Distillate Diesel	Biodiesel from Soybeans	Corn Ethanol	Corn Butanol	Algal Diesel
Total Capital Cost (million $)	$348	$383	$242	$242	$398	$52.9	$89.3	$262	$165
Capacity (million gal/yr)	172	37	212.8	212.8	90.44	45	45	62.16	10
Operating Costs ($/gal)[¥]	$0.06	$1.31	$0.94	$0.94	$1.20	$0.44	$0.47	$1.93	$1.88
Byproduct Credits ($/gal)	$0.06	$0.57	$0.00	$0.00	$0.19	$0.14	$0.30	$2.04	$0.00
Feedstock Yield (gal/dry short ton)	98.0	47.9	100	100	59	111[†]	118[‡]	87.02	N/A
Fuel LCOE* ($/gal)	$0.67	$2.94	$1.49	$1.49	$2.27	$3.91	$1.86	$2.38	$4.05
Year$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$

[¥] *Operating Costs only represent the costs to operate the facility and do not include the feedstock costs.*

** LCOE is calculated within BASE using feedstock costs that vary. Results reported here are for example only, and use a fixed charge rate of 0.132 and feedstock cost of $40/dry short ton for lignocellulosic biomass, $383/dry short ton for soybeans [$10/bushel, 13% moisture, 60 lb (wet) per bushel], or $168/dry short ton for corn ($4/bushel, 56 lb/bushel, 15% moisture).*

[†] *Based on 2.9 gal/bushel*

[‡] *Based on 2.8 gal/bushel*

While a large number of biofuels were included in this study, there are other potential biofuels that were not included. For example, there is a classification of biofuels that has recently become commercial—"hydrogenated fuels"—where natural plant oils are reacted with hydrogen over a catalyst. This serves to saturate double bonds and remove oxygen from the oils, thus creating high cetane diesel and jet fuels. Dynamic Fuels, LLC and Neste-oil are two companies that are producing these fuels on a commercial scale from a variety of oil feedstocks. These fuels were not included in the TEF project, because good cost models or data were not currently available. Moreover, the economics are anticipated to largely mirror those of biodiesel (transesterification), where the majority of the cost is associated with the feedstock itself.

Appendix F provides a full description of the conversion costs and efficiencies as well as references and reasoning behind the selection of those references.

3.7. Delivery and Dispensing Costs for Conventional Fuels and Biofuels

Simple estimates of the costs to deliver and dispense biofuels were used in this study. The *Annual Energy Outlook 2011*, Table 131 (Components of Selected Petroleum Product Prices), breaks out the fuel wholesale price, distribution costs, and taxes (energy, federal, and state). The distribution cost segment represents "the part of the supply chain where wholesale gasoline is brought to a retail station and sold to the final consumer" (EIA, 2011a). Fuel distribution costs were obtained from the *Annual Energy Outlook* for conventional fuels, and the TEF fuel infrastructure task for ethanol and biodiesel. Drop-in fuels were assumed to have the same distribution cost as their conventional counterparts. Since bunker fuel distribution costs were not estimated in the *Annual Energy Outlook*, they were set to the same cost as jet fuel ($0.00/gal) to be consistent with EIA.

Ethanol distribution costs were estimated by the TEF Fuels Infrastructure Team at $0.13/gal (2009$), which is higher than gasoline costs that were based on a delivery cost calculator and references (Morrow, Griffin, and Matthews 2006; U.S. Government Accountability Office 2007). Since biodiesel has distribution issues similar to ethanol, the biodiesel distribution and marketing costs were set to equal ethanol's costs. In addition, pyrolysis products, FT diesel, and algal diesel were considered drop-in fuels for this analysis and were assumed to use the same distribution systems as gasoline, diesel, jet fuel, and bunker fuel. As a result, their distribution costs are set equal to the conventional fuels in that market. Butanol was considered to have distribution issues similar to ethanol in 2020, but was considered a proxy for a fermentative drop-in gasoline replacement in 2050. Therefore, the 2050 distribution cost of butanol was set equal to the 2050 distribution cost of gasoline.

Figure 3.4 shows the fuel distribution and marketing costs used in this analysis.

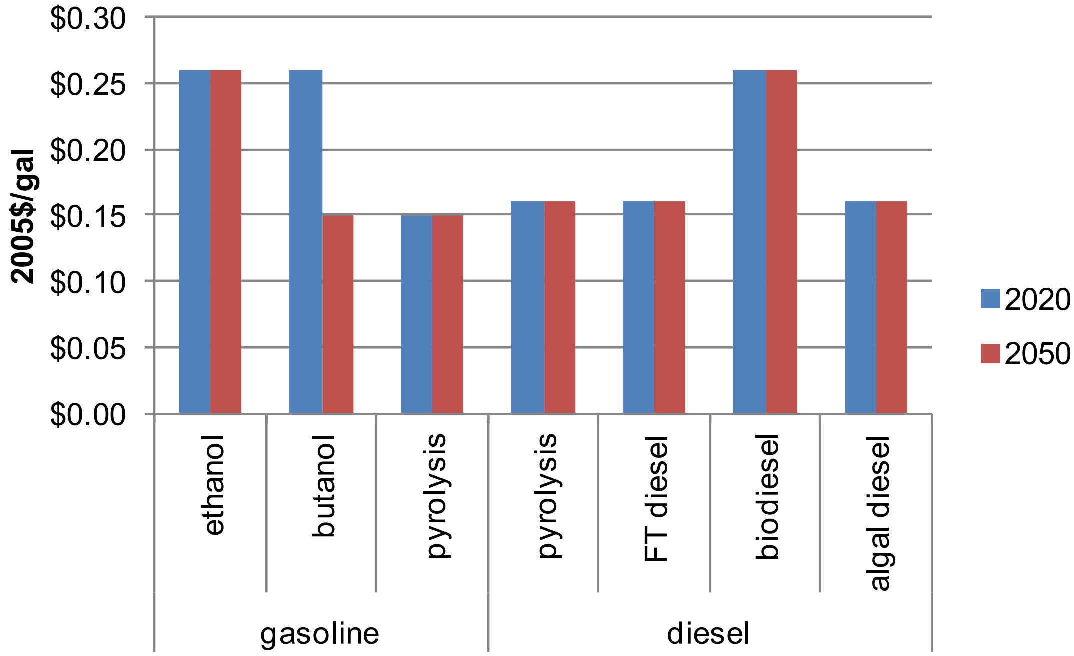


Figure 3.4. Fuel distribution and marketing costs
(Sources: DOE 2011a, Morrow et al. 2006, U.S. Government Accountability Office 2007)

Appendix G provides a full description of delivery and dispensing costs.

3.8. Conventional Fuel Price Projections

Projected fuel prices were either taken directly from EIA's *Annual Energy Outlook 2011* (EIA 2011a) in the case of the 2020 scenario, or extrapolated from *Annual Energy Outlook* data, in the case of the 2050 scenario. Federal and state motor fuels taxes were subtracted from the prices based on EIA sources. Table 3.7 shows the conventional fuel prices used in this analysis.

Table 3.7. Pricing Data Used in the BASE Model
[Data from Annual Energy Outlook 2011 (EIA, 2011a) (2050 values are extrapolations)]

Fuel	Year	BASE Value	BASE Units
Gasoline	2020	2.66	2005$/gallon
Gasoline	2050	3.15	2005$/gallon
Diesel	2020	2.75	2005$/gallon
Diesel	2050	3.25	2005$/gallon
Jet Fuel	2020	2.68	2005$/gallon diesel equivalent
Jet Fuel	2050	3.31	2005$/gallon diesel equivalent
Bunker Fuel	2020	1.74	2005$/gallon diesel equivalent
Bunker Fuel	2050	1.88	2005$/gallon diesel equivalent

Demand elasticities, the effect of increased/decreased demand on the price of conventional fuels, were considered for this analysis. See Appendix N for a review of price elasticities. Inelastic prices were chosen, because the level of elasticity is especially challenging to estimate for long-term trends. Additional review of potential elasticities should be considered in future analysis.

Appendix H provides a full description of conventional fuel price projections.

3.9. Fuel Market Sizes

Projected market sizes are either taken directly from EIA's *Annual Energy Outlook 2011* (EIA 2011a), in the case of the 2020 scenario, or extrapolated from *AEO* data, in the case of the 2050 scenario. The total volume of the gasoline market was estimated by summing the gasoline market size with the E85 market size [once the E85 market size was converted to a gallon gasoline equivalent (gge) basis]. The total volume of the diesel market was estimated by summing the diesel market size with the biodiesel and "other biomass-derived fuels" market sizes [once the latter two were converted to a gallon diesel equivalent (gde) basis]. Market sizes for liquefied petroleum gas and "distillate fuel (other than diesel)" were reported in the *AEO*, but they were not included in the default market sizes for BASE. All relative and absolute increases or decreases in market size for each of the fuels are based off of *AEO* assumptions. Table 3.8 shows the fuel market sizes used in this analysis. Due to a lack of information on market elasticity (i.e., how changes in prices affect market size) constant market sizes were used throughout this analysis.

Table 3.8. Market Size Data Used in the BASE Model

(Data sources referenced in text.)

Market	Annual Energy Outlook Market	Year	BASE Value	BASE Units
Electricity	**Total**	2020	3.99 billion	Megawatt-hours (MWh)
	Electricity	2020	3.98 billion	MWh
	PHEV - Electricity	2020	10.00 million	MWh
Electricity	**Total**	2050	5.02 billion	MWh
	Electricity	2050	4.99 billion	MWh
	PHEV - Electricity	2050	34.00 million	MWh
Gasoline	**Total**	2020	144.00 billion	Gallons gasoline equivalent/year
	Gasoline	2020	141.00 billion	Gallons/year
	E85	2020	2.65 billion	Gallons gasoline equivalent/year
Gasoline	**Total**	2050	170.00 billion	Gallons gasoline equivalent/year
	Gasoline	2050	158.00 billion	Gallons/year
	E85	2050	11.50 billion	Gallons gasoline equivalent/year
Diesel	**Total**	2020	62.00 billion	Gallons diesel equivalent/year
	Diesel	2020	59.90 billion	Gallons/year
	Biodiesel	2020	1.44 billion	Gallons diesel equivalent/year
	Other Biomass-Derived Fuels	2020	683.00 million	Gallons diesel equivalent/year
Diesel	**Total**	2050	92.50 billion	Gallons diesel equivalent/year
	Diesel	2050	79.30 billion	Gallons/year
	Biodiesel	2050	1.88 billion	Gallons diesel equivalent/year
	Other Biomass-Derived Fuels	2050	11.30 billion	Gallons diesel equivalent/year
Jet Fuel		2020	24.30 billion	Gallons diesel equivalent/year
Jet Fuel		2050	27.60 billion	Gallons diesel equivalent/year
Bunker Fuel		2020	5.82 billion	Gallons diesel equivalent/year
Bunker Fuel		2050	6.09 billion	Gallons diesel equivalent/year

Appendix I provides a full description of market sizes used in this analysis.

3.10. Electricity Cost and Performance Data

The data used to model electricity generation technologies and fuels were largely based on EIA's *Annual Energy Outlook 2011* reference scenario projections, however, in some cases, modifications to the *Annual Energy Outlook 2011* data were made as discussed below and in Appendix J. In the *Annual Energy Outlook 2011*, EIA made projections of the commodity price index. To avoid uncertainties associated with these commodity index projections, the capital costs used in the BASE model calculations remove the effects of projected commodity index. In other words, the BASE model implicitly assumes a commodity index of 1.0 for all years.

Table 3.9 shows the technologies considered in this analysis, their costs, and heat rates. The column labeled "capital net commodity index" reflects modifications to the capital cost that have been made for the BASE model to remove commodity index effects. The "maximum annual capacity factor" values for dispatchable technologies (all technologies except wind and solar) were based on data used in NREL's ReEDS model (Short et al. 2011) and consider typical planned and forced outage rates for these plant categories. For the variable renewable generation technologies [wind, photovoltaics (PV), and concentrating solar power CSP)], the annual capacity factors shown are from *Annual Energy Outlook 2011*. Integration cost adders for wind and PV are set to \$8/MWh (in 2005\$) based loosely on estimates from the Eastern Wind Integration and Transmission (EWITS) study. Another category of electricity generation technology, referred to as "other RE" [other renewable energy] is included in BASE and represents dispatchable renewable (but non-biomass) resources, including geothermal, hydropower, and CSP with thermal storage. The BASE model does not include supply curves for the technologies under the "other RE" category. Instead, BASE uses single-point estimates of technology cost and performance projections for geothermal as the representative dispatchable non-biomass renewable technology. The "Transparent Cost Database" (http://en.openei.org/apps/TCDB/) was not available when this data was collected and thus was not used. The values used here are consistent with those in the database.

Heat rate is defined as the overall thermal performance (energy efficiency) of a power plant calculated as the heat supplied to the power plant divided by the electricity generated.

Note that several types of biopower production are not included. Production of power from municipal solid waste and landfill gas sources was not included, because supply curves were not available for either resource. In addition, co-firing of biomass with coal was not included, because co-firing is assumed to have similar costs to biopower generation when capital costs are fully included and the plants have large capacities. In this analysis, capital costs are fully included, and the biopower costs are based on large-scale facilities.

Table 3.9. 2020 Cost Data for Electricity Generation Technologies Used in the BASE Model (2005$)

(Data sources referenced in text.)

Technology	Capital Net Commodity Index ($/kW)	Fixed Charge Rate	Fixed Operation and Maintenance (O&M) ($/kW-yr)	Variable O&M ($/MWh)	Maximum Annual Capacity Factor	Heat Rate (10^6Btu/MWh)
Nuclear	$4,380	0.144	$80.01	$1.83	0.90	10.45
Coal	$2,487	0.139	$26.75	$3.83	0.85	8.77
Natural Gas-(NG) Closed Cycle (CC)	$867	0.133	$13.18	$2.80	0.90	6.37
NG-Combustion Turbine (CT)	$571	0.119	$13.25	$6.29	0.92	9.01
Other RE	$5,474	0.109	$97.87	$8.69	0.85	-
Biopower	$3,247	0.114	$90.60	$5.87	0.84	13.50
Wind	$2,175	0.098	$25.30	$0.00	0.33	-
PV	$3,660	0.097	$23.47	$0.00	0.25	-
CSP	$3,075	0.104	$57.69	$0.00	0.26	-

Table 3.10 is similar to Table 3.9; however, 2035 cost and performance data are shown instead of 2020. In the BASE model, 2050 scenarios were evaluated using the 2035 cost and performance data provided here.

Table 3.10. 2035 Cost Data for Electricity Generation Technologies Used in the BASE Model (2005$)

(Data sources referenced in text.)

Technology	Capital Net Commodity Index ($/kW)	Fixed Charge Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Maximum Annual Capacity Factor	Heat Rate (10^6Btu/MWh)
Nuclear	$3,814	0.143	$80.01	$1.83	0.90	10.45
Coal	$2,360	0.139	$26.75	$3.83	0.85	8.74
Natural Gas-CC	$793	0.131	$13.18	$2.80	0.90	6.33
Natural Gas-CT	$508	0.118	$13.25	$6.29	0.92	8.55
Other RE	$5,474	0.108	$113.25	$8.69	0.85	-
Biopower	$2,993	0.112	$90.60	$5.41	0.84	13.50
Wind	$2,154	0.097	$25.30	$0.00	0.33	-
PV	$2,771	0.096	$23.47	$0.00	0.25	-
CSP	$2,230	0.103	$57.69	$0.00	0.26	-

Fossil fuel and uranium price projections for 2020 and 2050 were also based on *Annual Energy Outlook 2011* projections. Because of the greater degree of elasticity in fossil-fuel prices (especially natural gas) compared to uranium, linear supply curves were used for natural gas and coal. The methodology to develop the supply curves is described in (Short et al. 2011) and the supply curves presented here are the same as those used in the ReEDS model. In short, fossil-fuel elasticity parameters were derived using a linear regression of fossil-fuel consumption and price across three cases from *Annual Energy Outlook 2011*: the reference case, high economic growth, and low economic growth cases. The elasticity parameters represent the increase in per unit price of fossil fuel for each additional unit of electric sector fuel consumption. The elasticity parameters were assumed to not vary over time. In addition to the elasticity parameters, a minimum fixed fossil-fuel price was used to fully define the linear supply curve; the y-intercept of a fossil-fuel supply curve was defined by the fixed price and the slope was defined by the elasticity parameter. The fixed price changes over time and was calibrated to match the *Annual Energy Outlook 2011* reference case consumption and price for all years. To obtain the 2050 supply curve, the fixed price was based on extrapolations from 2025 to 2035 in the *Annual Energy Outlook 2011* reference case. Table 3.11 shows the uranium and fossil-fuel prices and elasticities for 2020 and 2050.

Table 3.11. 2020 and 2050 Fossil-Fuel and Uranium Prices (2005$)

(Data sources referenced in text.)

Fuel	Elasticity ($/$10^6$Btu per Quad)	Price ($/$10^6$Btu)
2020 Natural Gas	0.322	$2.31
2020 Coal	0.044	$1.13
2020 Uranium	n/a	$0.75
2050 Natural Gas	0.322	$4.43
2050 Coal	0.044	$1.39
2050 Uranium	n/a	$1.19

Appendix J provides a full description of electricity cost and performance data used in this analysis.

3.11. Life Cycle GHG Emissions and Petroleum Consumption

Well-to-wheel (WTW) and well-to-tank (WTT) life cycle data for GHG emissions (Figures 3.5 and 3.6) and petroleum consumption (Figures 3.7 and 3.8) used in the BASE model are illustrated for the years 2020 and 2050. The primary data source is the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model version 1.8d, created by the Argonne National Laboratory (*GREET Model: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation*, ANL 2011). Supplemental fuel pathways for microalgae-based fuels grown in an open pond were partially generated in the GHGenius model version 3.19a, created by $(S\&T)^2$ (2004). Supplemental fuel pathways for pyrolysis-oil-based fuels were partially based on GREET and a SimaPro v.7.2 model of pyrolysis oil processing to gasoline and diesel (Hsu 2011).

Fuel pathways for the 2020 and 2050 scenarios were both modeled based on default GREET assumptions for the year 2020, because 2050 default parameters were not available. The electricity grid for 2020 and 2050 and associated life cycle GHG emission intensities were modeled based on the 2011 Renewable Energy Future's (REF) study's 80% renewables projections. Parameters for specific fuel pathways were modified to reflect conversion efficiencies assumed for 2020 and 2050 (as outlined in Section 3.6) (Mai et al. 2012) . Effects of indirect land use change on GHG emissions, though important to Federal policy-making, were not included because the magnitude of those effects vary dramatically and are controversial. In addition, doing so would have added more complexity than could be addressed within the scope of this analysis.

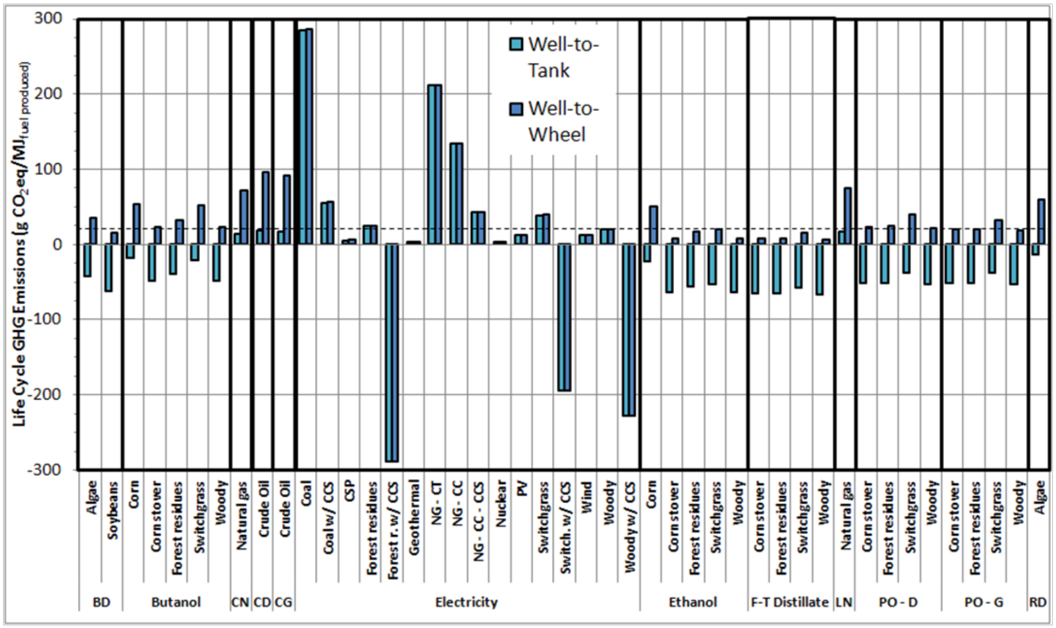


Figure 3.5. WTW and WTT life cycle GHG emission estimates used in the BASE model for 2020
The dotted line represents an 80% GHG emission reduction from gasoline.
[Sources: Argonne National Laboratory 2011, (S&T) Consultants 2011, Hsu 2011, Spath and Mann 2004, Mullins et al. 2010, Tao and Aden 2011, Mai et al. 2012]
BD = biodiesel; CNG = compressed natural gas; CD = conventional diesel; CG = conventional gasoline; F-T = Fischer Tropsch; LNG – liquefied natural gas; PO = pyrolysis oil; RD = renewable diesel.

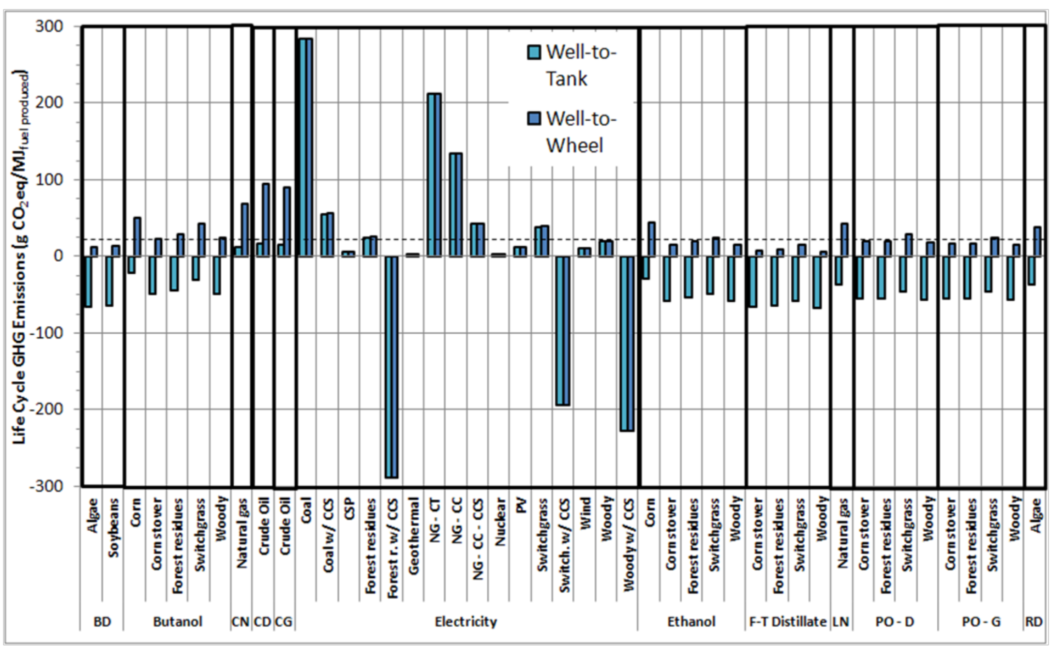


Figure 3.6. WTW and WTT life cycle GHG emission estimates used in the BASE model for 2050
The dotted line represents an 80% GHG emission reduction from gasoline**.**
[Sources: Argonne National Laboratory 2011, (S&T) Consultants 2011, Hsu 2011, Spath and Mann 2004, Mullins et al. 2010, Tao and Aden 2011, Mai et al. 2012]
BD = biodiesel; CNG = compressed natural gas; CD = conventional diesel; CG = conventional gasoline; F-T = Fischer Tropsch; LNG – liquefied natural gas; PO = pyrolysis oil; RD = renewable diesel.

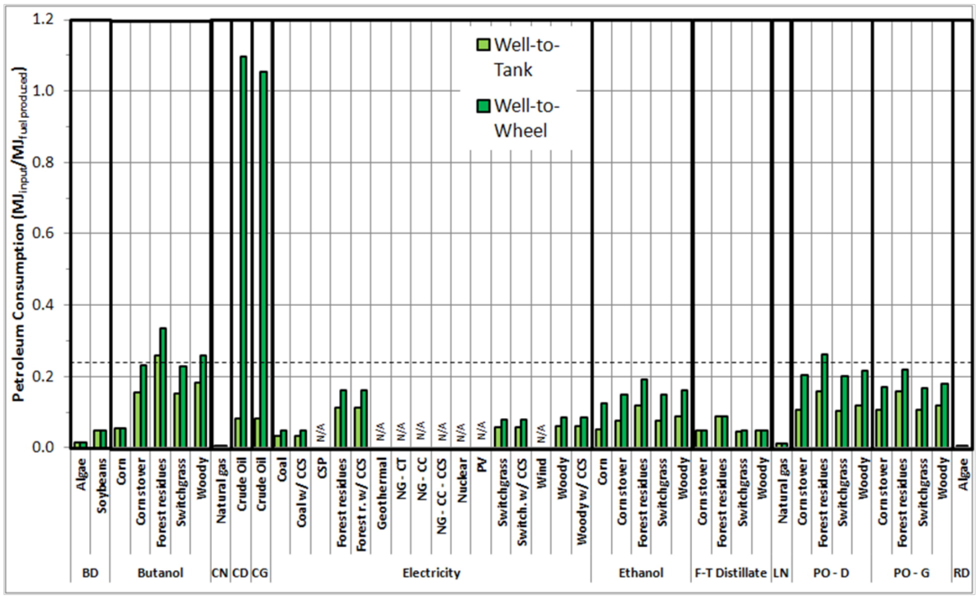


Figure 3.7. WTW and WTT life cycle petroleum consumption estimates used in the BASE model for 2020

The dotted line represents an 80% petroleum consumption reduction from gasoline.

[Sources: Argonne National Laboratory 2011, (S&T) Consultants 2011, Hsu 2011, Spath and Mann 2004, Mullins et al. 2010, Tao and Aden 2011, Mai et al. 2012]

CNG = compressed natural gas; CD = conventional diesel; CG = conventional gasoline; F-T = Fischer Tropsch; LNG – liquefied natural gas; PO = pyrolysis oil; RD = renewable diesel.

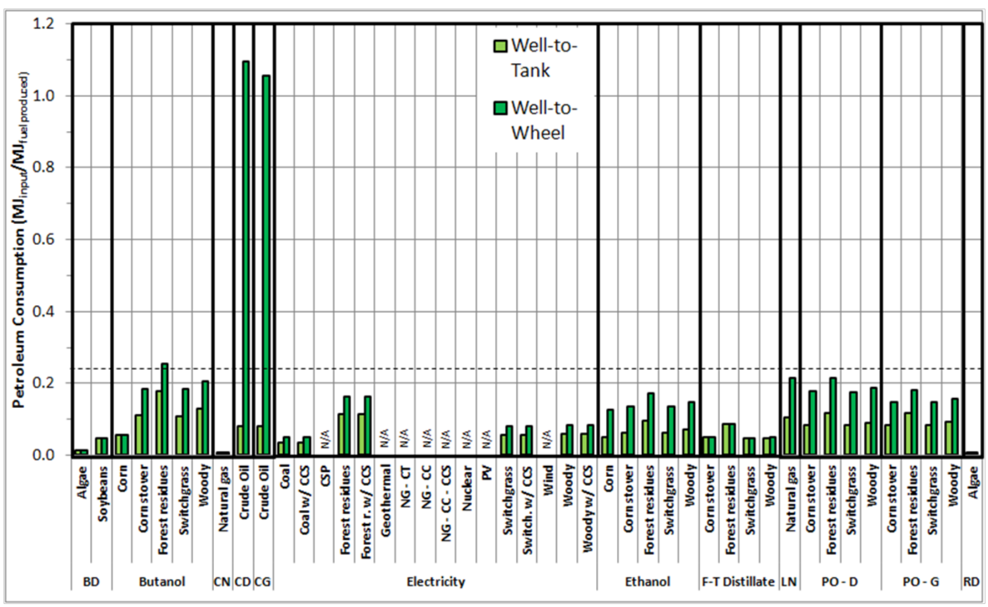


Figure 3.8. WTW and WTT life cycle petroleum consumption estimates used in the BASE model for 2050

The dotted line represents an 80% GHG emission or petroleum consumption reduction from gasoline.

(Sources: Argonne National Laboratory 2011, (S&T) Consultants 2011, Hsu 2011, Spath and Mann 2004, Mullins et al. 2010, Tao and Aden 2011, Mai et al. 2012)

CNG = compressed natural gas; CD = conventional diesel; CG = conventional gasoline; F-T = Fischer Tropsch; LNG – liquefied natural gas; PO = pyrolysis oil; RD = renewable diesel.

4. Results From Model Runs Using Default Data

This section reports the results that were generated by the BASE model using default data as described in Section 3 and the appendices. It includes a short presentation of levelized costs of fuels that were purchased by consumers and based on the default data above. The presentation is followed by projections of equilibrium states under mature market conditions for 2020 and 2050 in the electricity and transportation sectors. As previously discussed, the estimates are optimized end-points that may not be achieved due to many temporal reasons (e.g., retirement rates of and/or replacement of existing stock, conservative business decisions, uncertain and changing policies, lack of achievement of n^{th} plant projections due to lack of learning, and so on). The 2020 result is unlikely, because the timeframe is too soon for technologies to mature and markets to develop. Even with this probability, estimates are still useful in understanding how biomass might be utilized in mature markets, and whether market development faces larger hurdles.

4.1 Levelized Cost of Energy Results

Fuels and electricity compete on an energy-equivalent levelized cost of energy (LCOE) basis. The BASE model presumes that the consumer pays for the product at a levelized cost due to competition in mature markets. The liquid biofuels competing against gasoline include corn ethanol, cellulosic ethanol, corn butanol, cellulosic butanol, and pyrolysis oil-based gasoline. LCOEs for those fuels are shown in Figure 4.1 (2020), and Figure 4.2 (2050), on a gallon-gasoline-equivalent (gge) basis. Conventional fuel price projections are shown for comparison.

Note that the cellulosic biofuels prices include multiple blue bars ranging from $40/dry short ton delivered biomass to $200/dry short ton. In 2020, at $40/dry short ton, the price of cellulosic ethanol and butanol is higher than that for the gasoline it is competing against; however, the price of pyrolysis-oil-based gasoline is slightly lower than gasoline. At higher feedstock prices, the price of pyrolysis-oil-based gasoline is higher than the competing gasoline. Corn-based ethanol and butanol are higher than the gasoline competition at both low and high corn prices (note that co-product value is included in the LCOE calculation).

The 2050 projections for gasoline price are higher than 2020, yet the biomass LCOE projections are lower, because projected technology improvements reduce feedstock and conversion costs. The result is that cellulosic and corn-based biofuels compete well with gasoline, when feedstock prices are $3.79/bushel for corn and up to $160/dry short ton for cellulosic feedstocks.

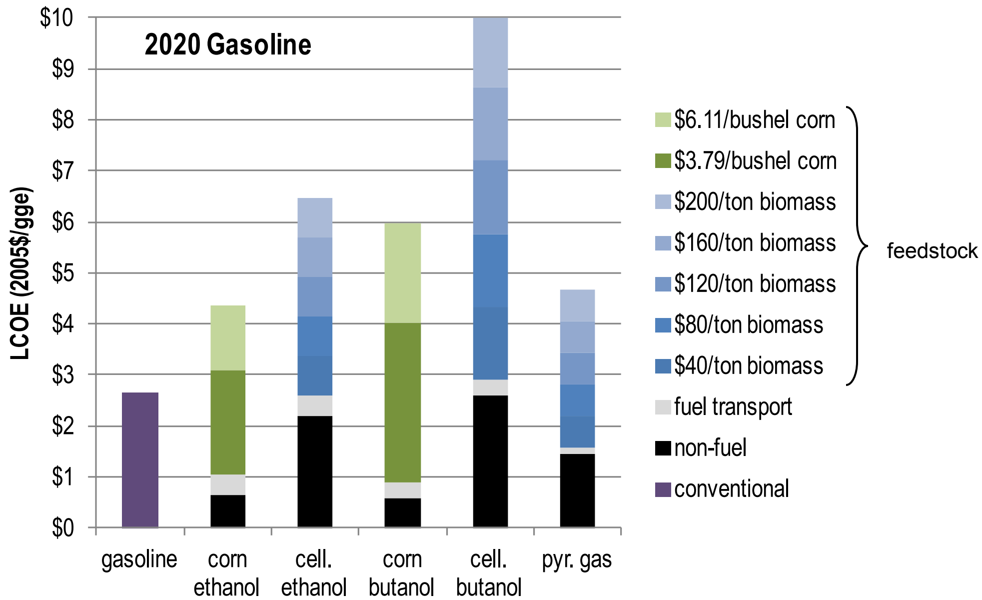


Figure 4.1. LCOE breakdown for gasoline-market fuels in 2020 with various feedstock prices
(Sources: Humbird et al. 2011, Jones et al. 2009, Swanson et al. 2010, Tao and Aden 2009, Davis et al. 2011, Tao and Aden 2011, DOE 2011a, DOE 2011b)

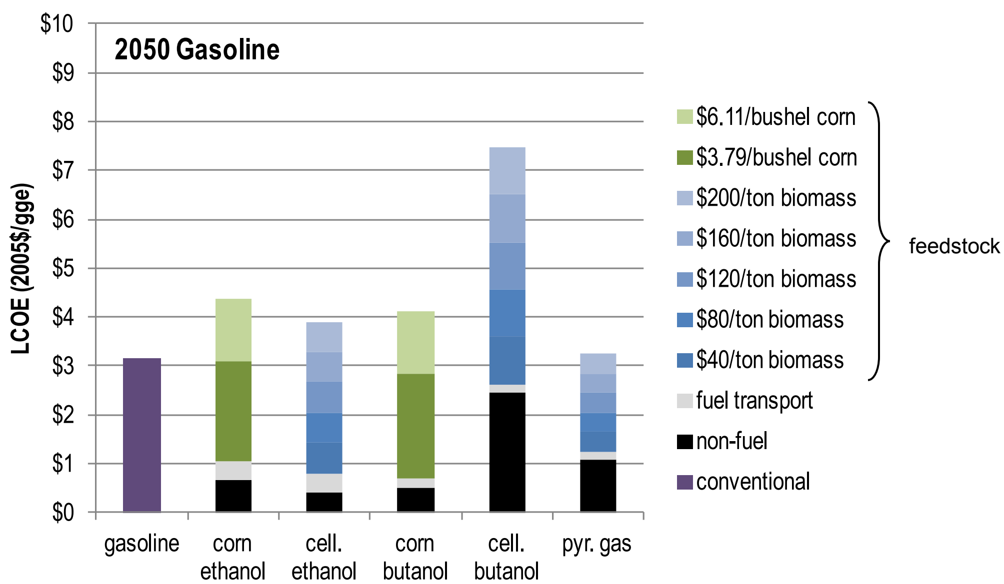


Figure 4.2. LCOE breakdown for gasoline-market fuels in 2050
(Sources: Humbird et al. 2011, Jones et al. 2009, Swanson et al. 2010, Tao and Aden 2009, Davis et al. 2011, Tao and Aden 2011, DOE 2011a, DOE 2011b)

The liquid biofuels competing against diesel, bunker fuel, and jet fuel include PO-based diesel, algal diesel, FT diesel, and soy-based biodiesel. LCOEs for those fuels are shown in Figure 4.3 (2020), and Figure 4.4 (2050), on a gde basis. Similar to the gasoline market, the PO-based diesel is less expensive than diesel and jet fuel in 2020 at low feedstock prices, and slightly more expensive at higher feedstock prices. FT diesel is much more costly in 2020, but becomes competitive in 2050, because of assumed technology improvements. Algal fuels are projected to be more expensive in both 2020 and 2050, although the difference between the LCOE for algal fuels and other biofuel options is much smaller in 2050.

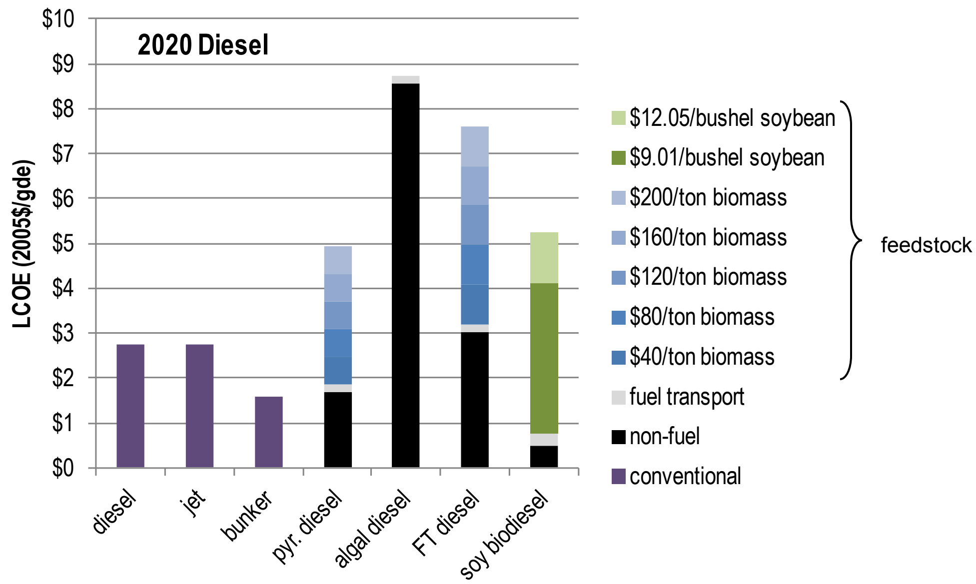


Figure 4.3. LCOE breakdown for diesel, jet, and bunker-market fuels in 2020
(Sources: Humbird et al. 2011, Jones et al. 2009, Swanson et al. 2010, Tao and Aden 2009, Davis et al. 2011, Tao and Aden 2011, DOE 2011a, DOE 2011b)

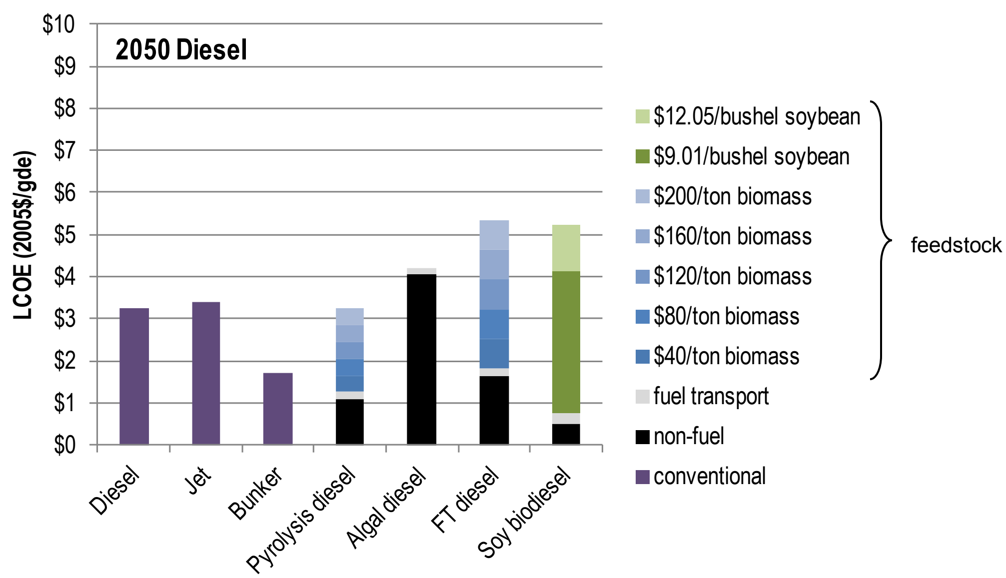


Figure 4.4. LCOE breakdown for diesel, jet, and bunker-market fuels in 2050
(Sources: Humbird et al. 2011, Jones et al. 2009, Swanson et al. 2010, Tao and Aden 2009, Davis et al. 2011, Tao and Aden 2011, DOE 2011a, DOE 2011b)

LCOEs for electricity are shown in Figures 4.5 and 4.6. Biopower is reported at several feedstock levels. Likewise, coal and natural-gas-based electricity are shown with multiple feedstock prices. Note that BASE has four load slices and provides different treatments for variable generation, as a result, the competition is not as straight forward as with liquid fuels. All technologies, except “other RE,” are projected to have lower LCOE between 2020 and 2050. Biopower is much more expensive than competing technologies unless the feedstock cost is less than $40/dry short ton. For simplicity, a heat content of 16 10^6Btu/dt is used for all biomass feedstocks in these figures. In reality, heat content depends upon feedstock and ranges from 14-18 10^6Btu/dt.

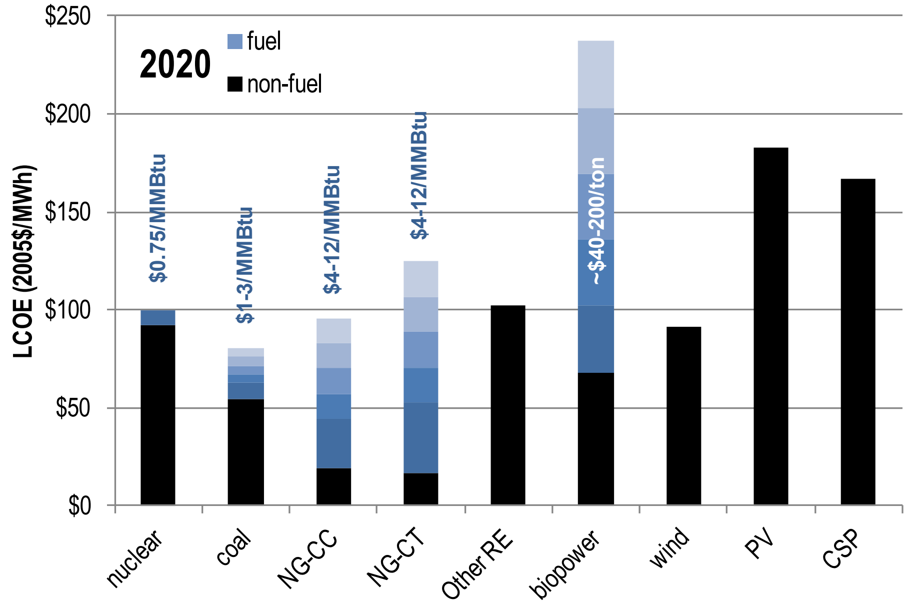


Figure 4.5. LCOE breakdown for electricity in 2020
(Sources: DOE 2011a, Short et al. 2011, Augustine et al. 2010)

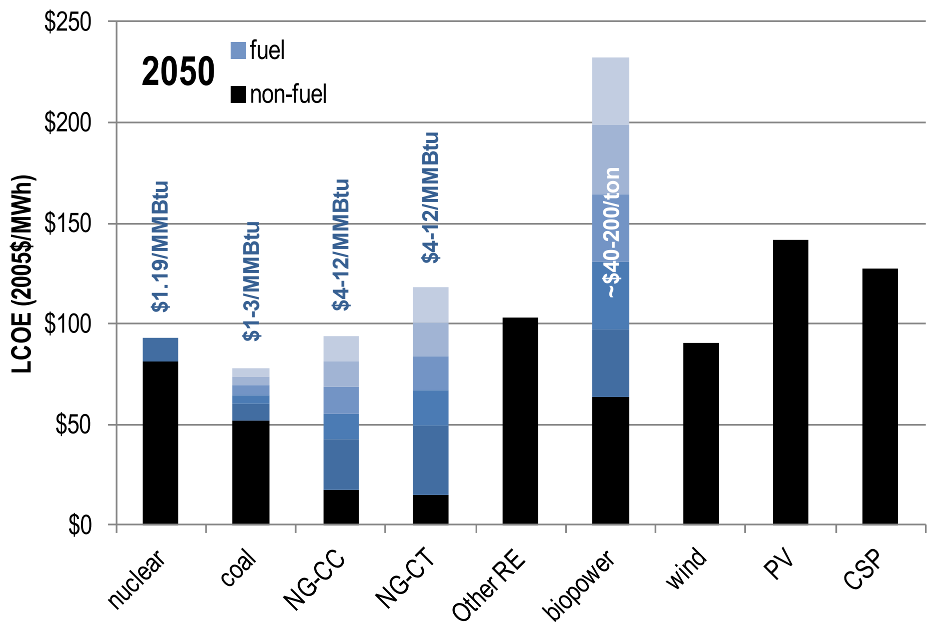


Figure 4.6. LCOE breakdown for electricity in 2050
(Sources: DOE 2011a, Short et al. 2011, Augustine et al. 2010)

4.2 Default Data Scenarios with Carbon Prices

The primary purpose of this analysis and the BASE model is to better understand if biomass might penetrate mature fuel and electricity markets, evaluate how much it could penetrate, and determine how it might be segregated between those markets. The effect of carbon cost on those issues is also considered, because setting carbon cost increases penetration of renewables in many markets and affects market performance.

Results are reported for three scenarios: carbon prices of $0/metric ton CO_2e, $40/metric ton CO_2e, and $80/metric ton CO_2e . The emissions used to calculate costs of carbon are based on full lifecycle (i.e., not just tailpipe) calculated as described in Section 3.11. Different emissions policies (e.g., tailpipe only) could result in different results.

Figure 4.7 shows the biomass-based fuel and electricity penetration in hypothetical mature 2020 markets. (See Table 3.8 for a review of the size of each of the markets.) Based on the LCOE data, biomass-based fuels permeate the fuel markets, especially the jet fuel and gasoline markets. The diesel market has less penetration, because there are fewer biomass options that are cost competitive with the conventional diesel fuel. Bunker fuel has a lower price than diesel, however, this analysis does not differentiate between the LCOE of the two fuel markets. As a result, biomass-based bunker fuel substitutes only reach low penetration in a hypothetical mature 2020 market. Because the LCOE for biopower is higher than most of the alternatives, it has minimal penetration. In all cases, biofuels become more pervasive when cost of carbon is evaluated, mainly because biofuels are less carbon intensive than conventional options. However, it is important to note that much of the biomass feedstock is utilized; if additional feedstock were available, the penetration in each of the markets could be much higher.

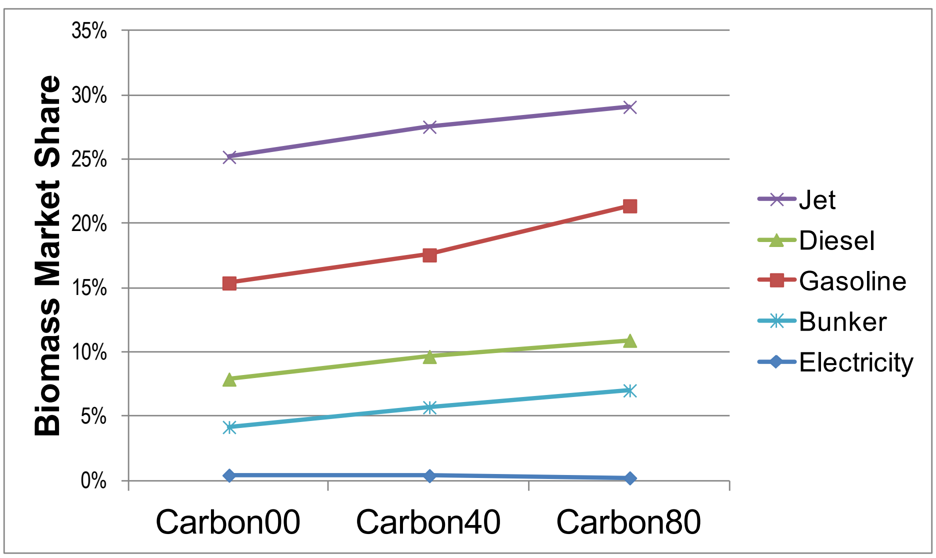


Figure 4.7. Biomass penetration in hypothetical mature 2020 markets with varied costs of carbon

In a mature 2050 market, the penetration of biofuels is more pronounced. Figure 4.8 shows the same penetration curves as in Figure 4.7, but in the later market. Biofuel options in the gasoline market are limited, due to the maximum allowable quantities of corn and increased value for biofuels in other markets; therefore, increasing the cost of carbon has little effect beyond $40/short ton. Biofuels also penetrate the jet and diesel markets more than in 2020, because of expected improvements in biomass technologies and increased diesel costs.

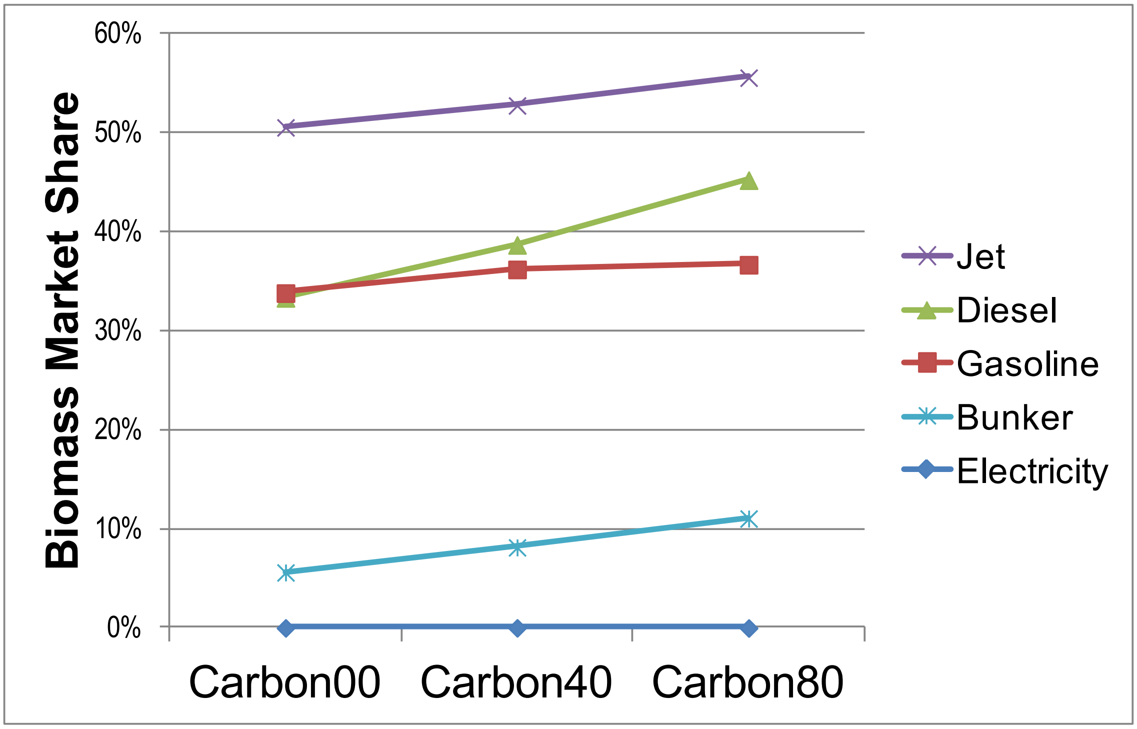


Figure 4.8. Biomass penetration in hypothetical mature 2050 markets with varied costs of carbon

As shown above, biopower is more expensive than other power options. However, biopower produces fewer GHGs than most of the other power options—especially those that can supply baseload. Because of this, one would expect biopower to have greater penetration, especially at high carbon costs. However, because there are more low-carbon power options, biopower has almost no penetration in this area. Figure 4.9 shows the electric sector market shares in the hypothetical mature 2020 market. Note that the market share for coal-based power goes down as the cost of carbon increases. It is replaced by variable renewable electricity options and other RE power.[9] Biopower does not penetrate, because it is too expensive. The 2050 market shares are similar and are shown in Figure 4.10.

[9] The "other RE" category in BASE represents all non-biopower-dispatchable technologies, including geothermal, hydropower, and CSP with storage.

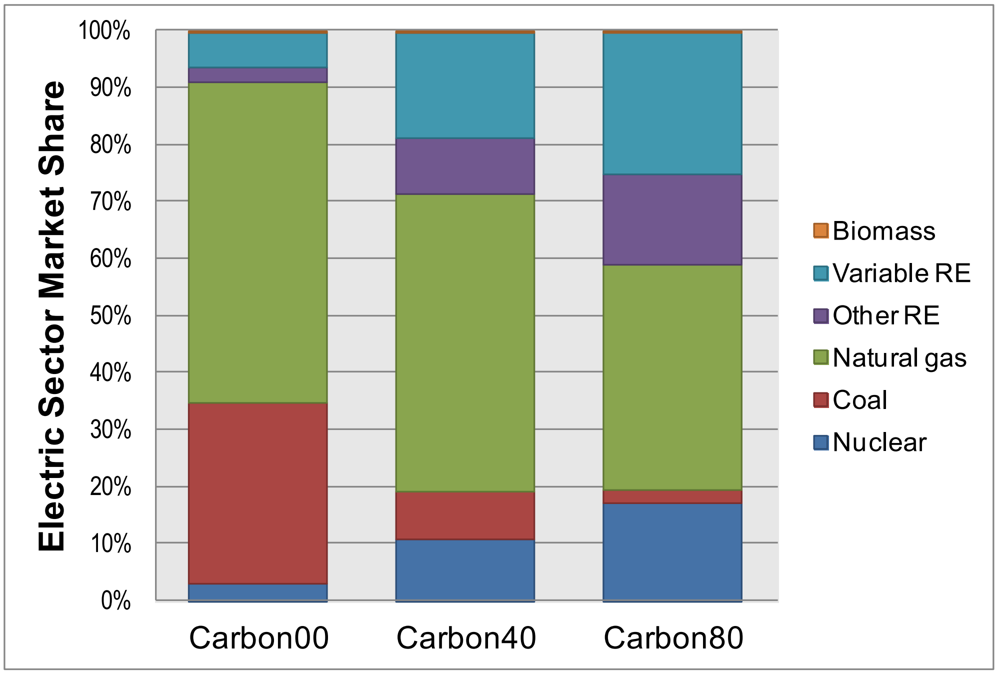


Figure 4.9. Biopower penetration in hypothetical mature 2020 markets with varied costs of carbon

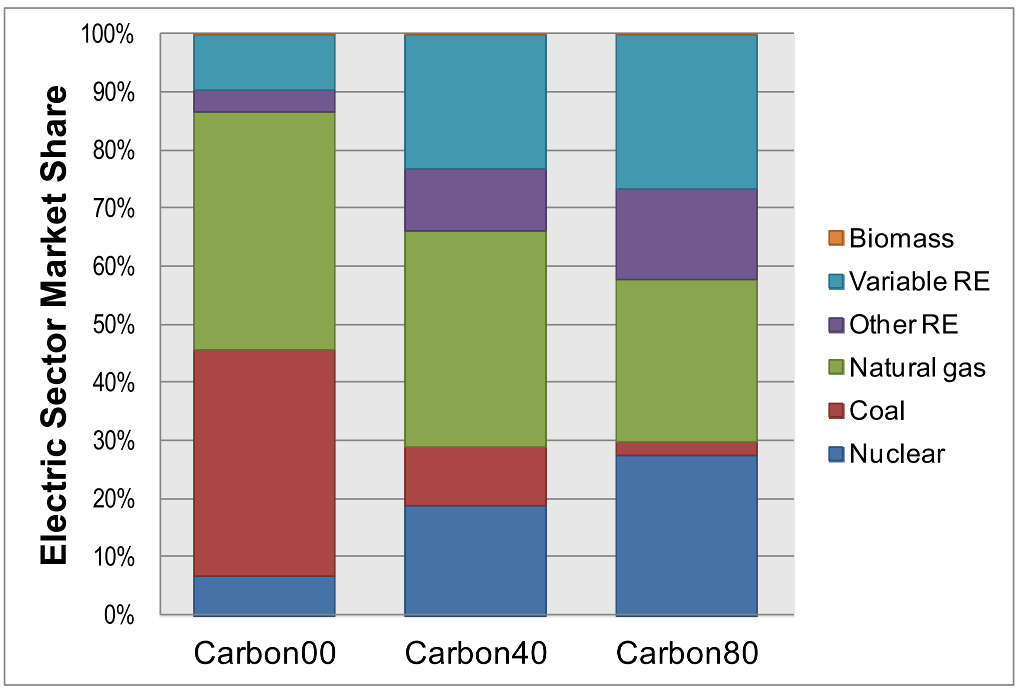


Figure 4.10. Biopower penetration in hypothetical mature 2050 markets with varied costs of carbon

As shown in Figures 4.11 and 4.12, coal and natural gas prices drop with increased costs of carbon. This is due to the reduced consumption of coal and natural gas in the electric sector. Because the fossil-fuel supply curves are derived using a linear regression, the rebound effect or dynamics in buildings/industrial sectors are unlikely to be adequately represented; therefore, actual changes are unlikely to be as dramatic as projected.

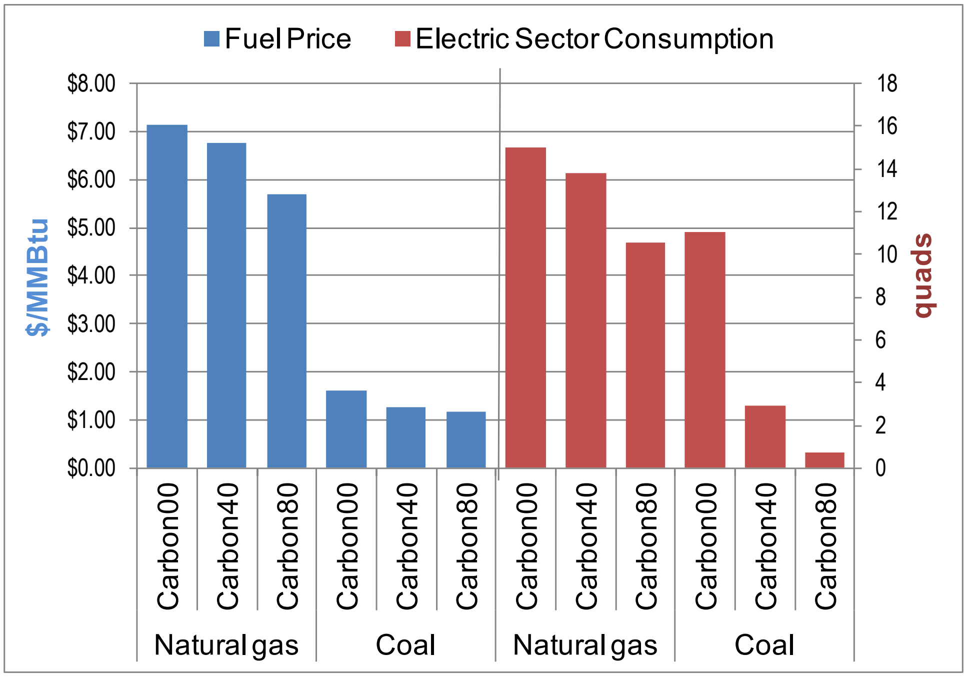


Figure 4.11. Effect of carbon cost on coal and natural gas prices and electric sector consumption in 2020

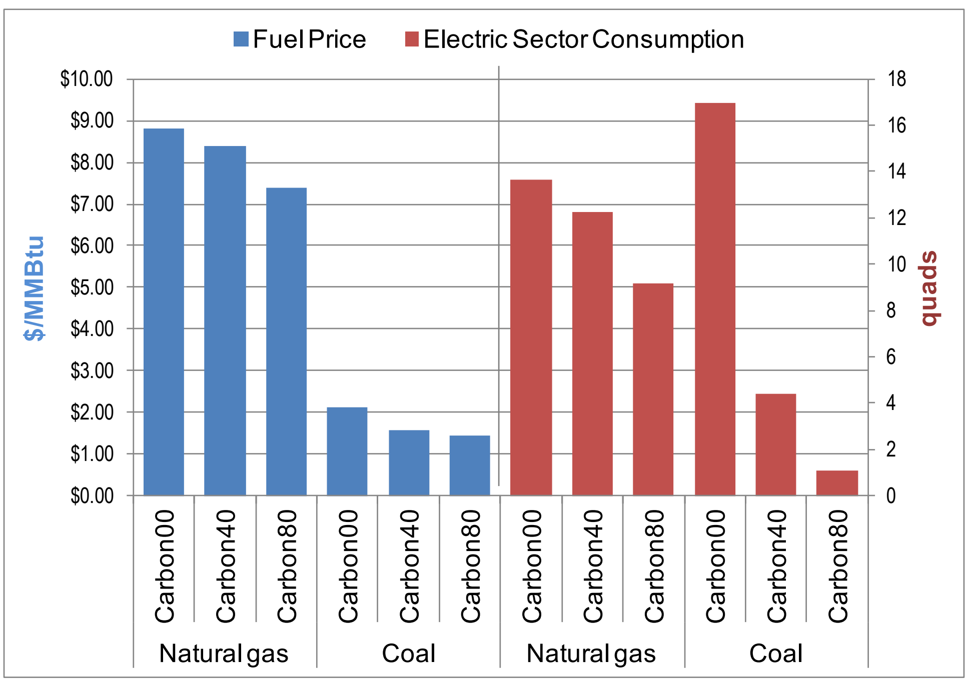


Figure 4.12. Effect of carbon cost on coal and natural gas prices and electric sector consumption in 2050

As expected with the type of logit function estimation used in BASE, multiple biofuels enter into each of the fuels markets. Figure 4.13 shows the penetration of each fuel in gallon gasoline equivalent for the gasoline market and gallon diesel equivalent for the diesel, jet, and bunker markets in the hypothetical mature 2020 markets. Algal diesel is not shown, because its penetration is negligible. Figure 4.14 shows the same data for the hypothetical mature 2050 market. Compared to other biofuels, PO-based gasoline shows the greatest penetration in the gasoline market and PO-based diesel shows the greatest penetration in the diesel and jet fuel markets. The figure also shows that, in 2050, pyrolysis gasoline and diesel are the largest consumers of lignocellulosic biomass, and algal fuels penetrate the diesel market at a noticeable level with high costs of carbon.

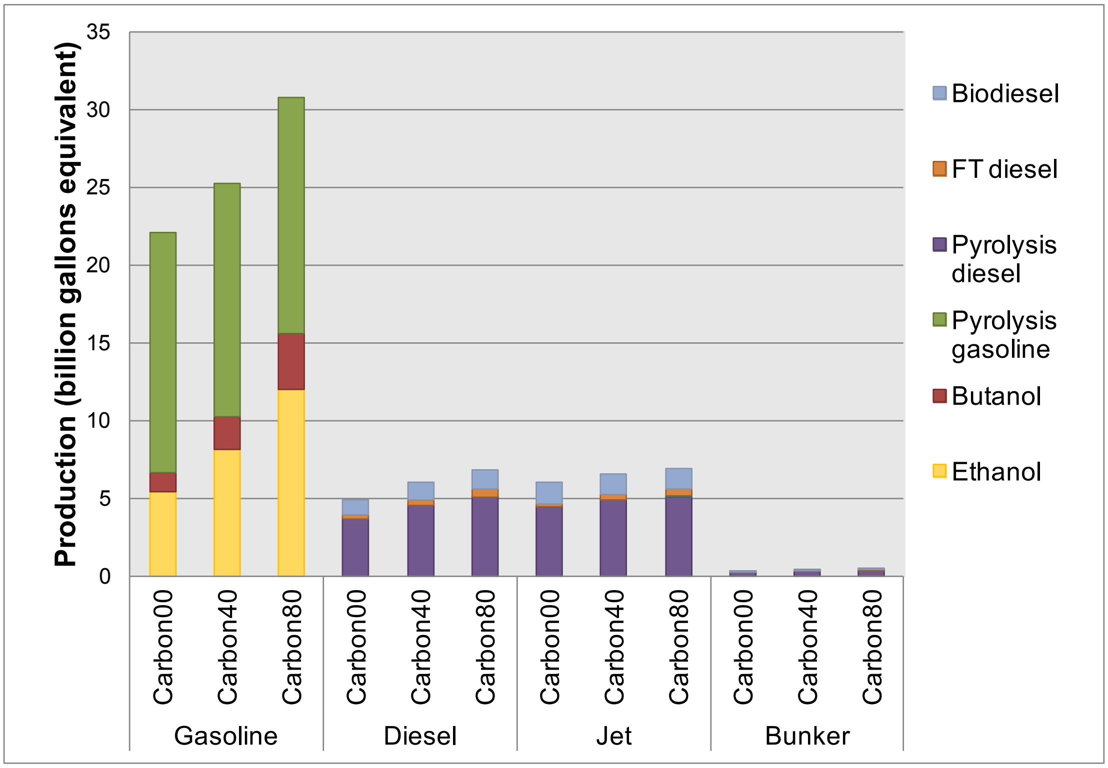


Figure 4.13. Biofuel utilization in each hypothetical mature 2020 fuel market with varied costs of carbon

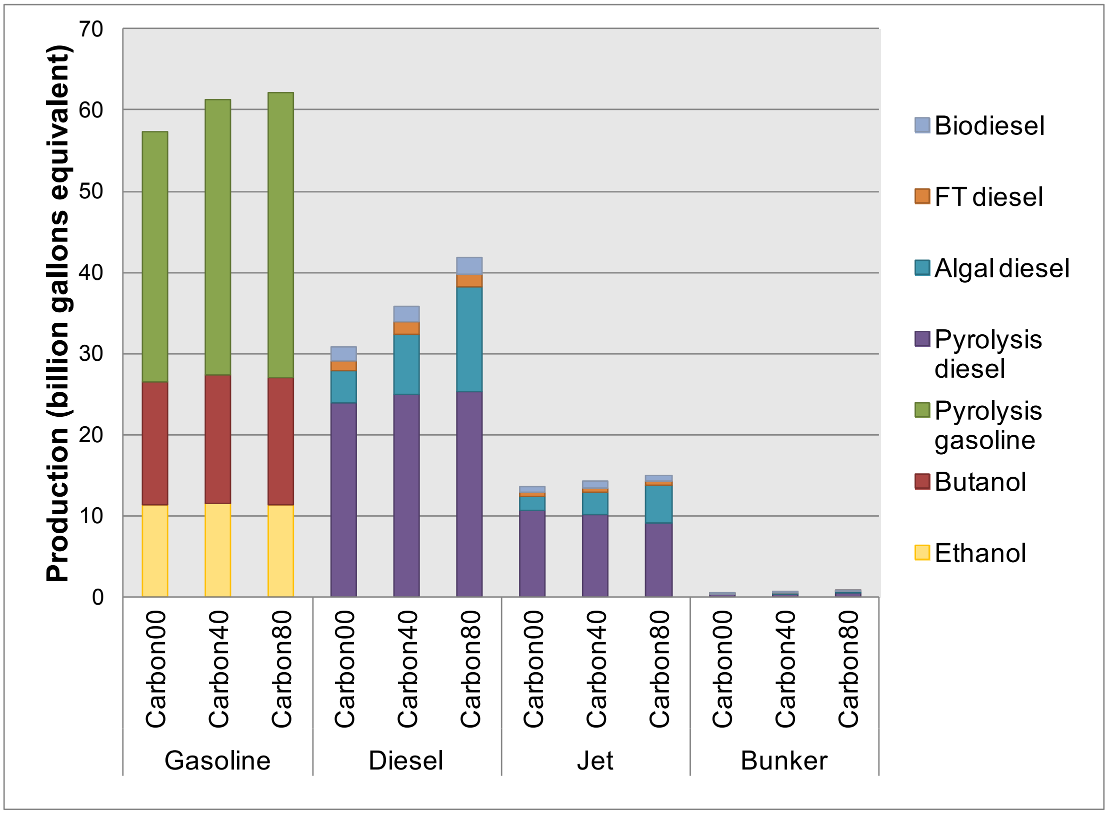


Figure 4.14. Biofuel utilization in each hypothetical mature 2050 fuel market

Another way to look at the same data is to calculate how many dry short tons of biomass (including corn grain and soybeans) are used to produce the biofuels that are consumed in the fuel markets. Figures 4.15 and 4.16 exhibit data for 2020 and 2050, respectively. Note that by summing the bars in Figure 4.15, one can estimate the total biomass use in the hypothetical mature 2020 case with no cost of carbon. That sum is 560 million dry tons. The total biomass use in the hypothetical mature 2050 case with no cost of carbon is 1,090 million dry tons.

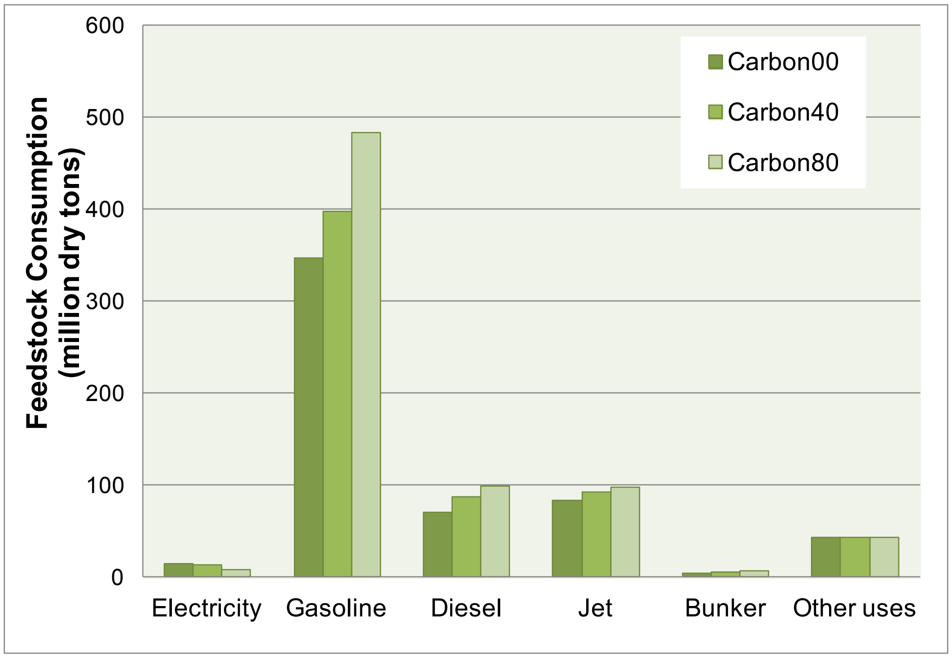


Figure 4.15. Biomass utilization in each hypothetical mature 2020 fuel market with varied costs of carbon

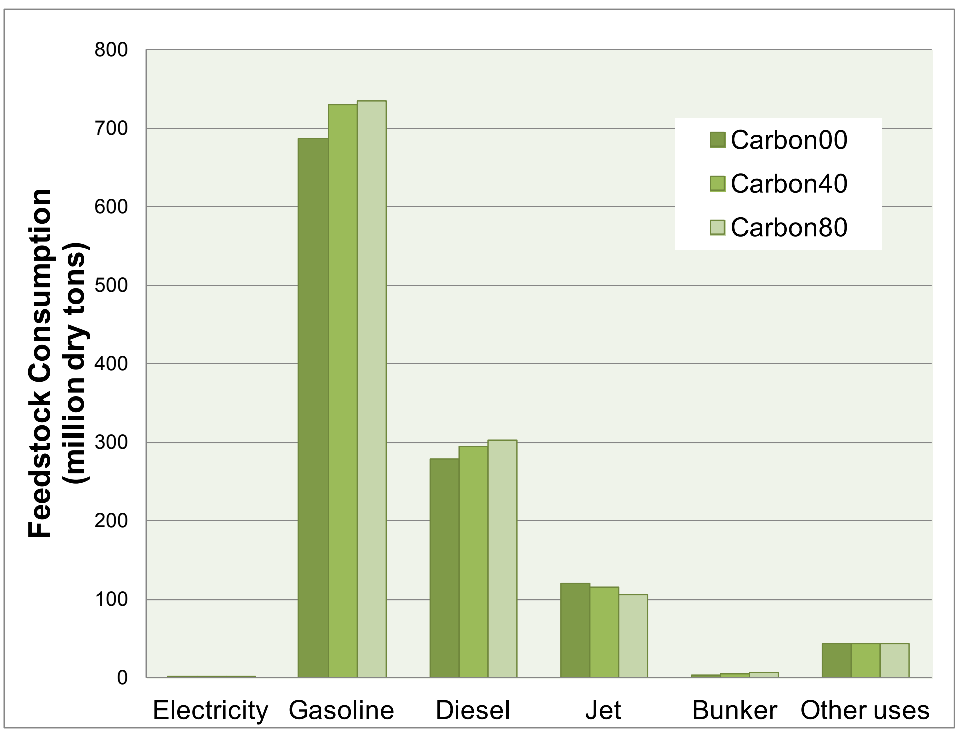


Figure 4.16. Biomass utilization in each hypothetical mature 2050 fuel market with varied costs of carbon

The data in Figures 4.15 and 4.16 are segregated to the fuels provided in each market in Figures 4.17 and 4.18. Ethanol, butanol, and PO-based gasoline compete in the gasoline market. PO-based diesel, FT diesel, and biodiesel compete in the diesel, jet fuel, and bunker fuel markets.

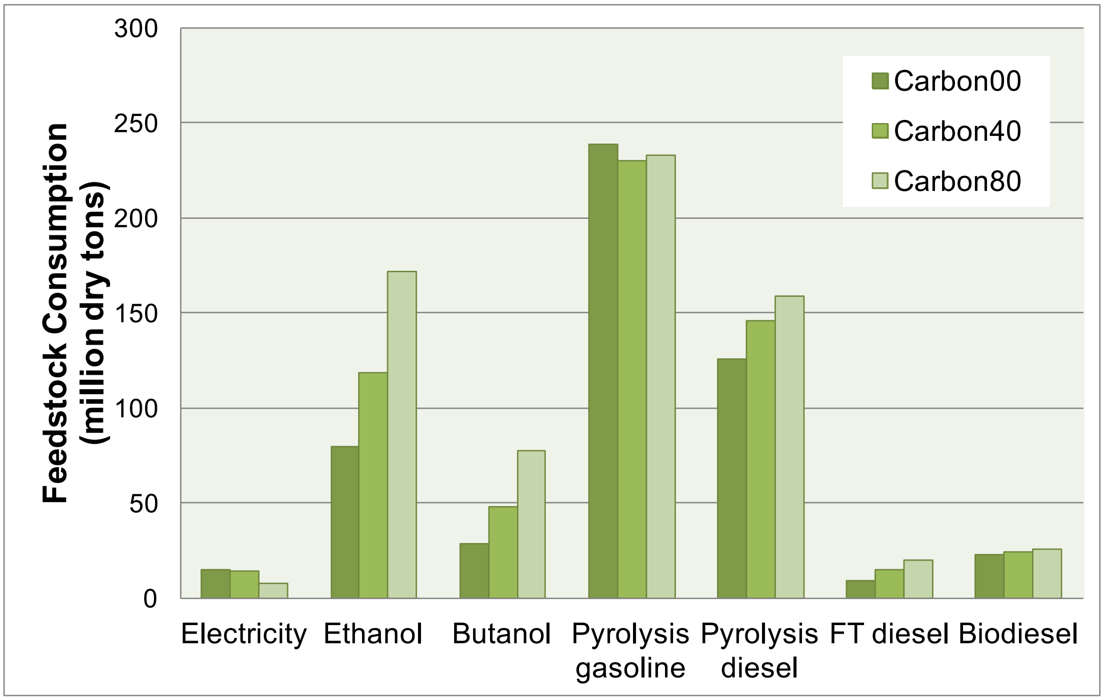


Figure 4.17. Biomass utilization by fuel type in the hypothetical mature 2020 fuel markets with varied costs of carbon

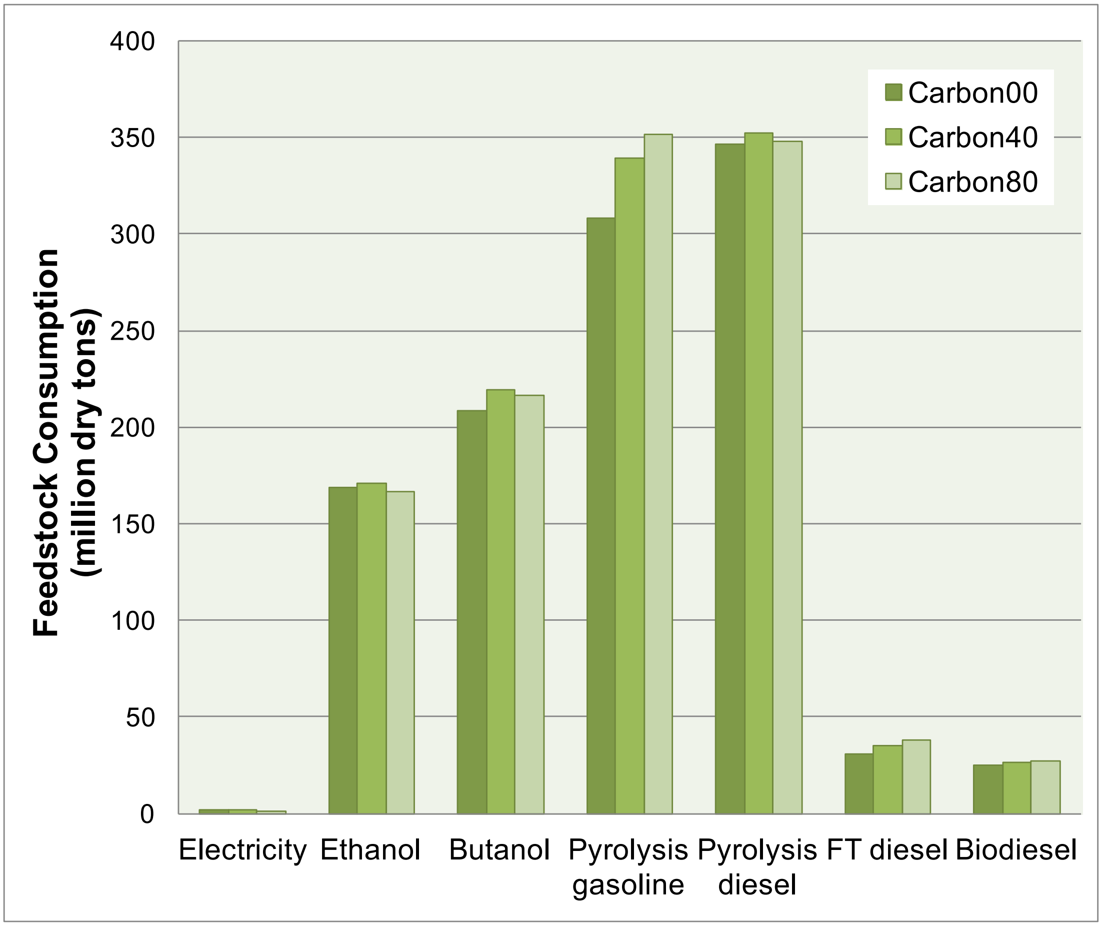


Figure 4.18. Biomass utilization by fuel type in the hypothetical mature 2050 fuel markets with varied costs of carbon

Finally, the data are segregated into feedstocks in Figures 4.19 and 4.20. The total consumption of lignocellulosic biomass in the hypothetical mature 2020 fuel market with no cost of carbon is 470 million dry short tons per year; in 2050 it is 880 million dry short tons per year. Much of the additional fuel generation shown above is also due to increases in corn consumption for ethanol and butanol (used in the gasoline market).

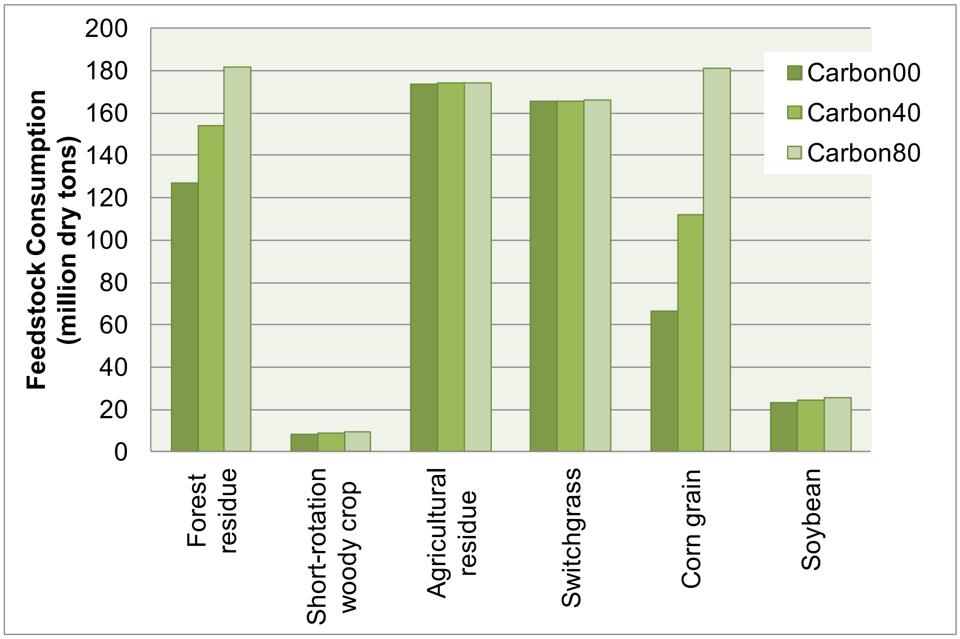


Figure 4.19. Biomass utilization by feedstock type in the hypothetical mature 2020 fuel markets with varied costs of carbon

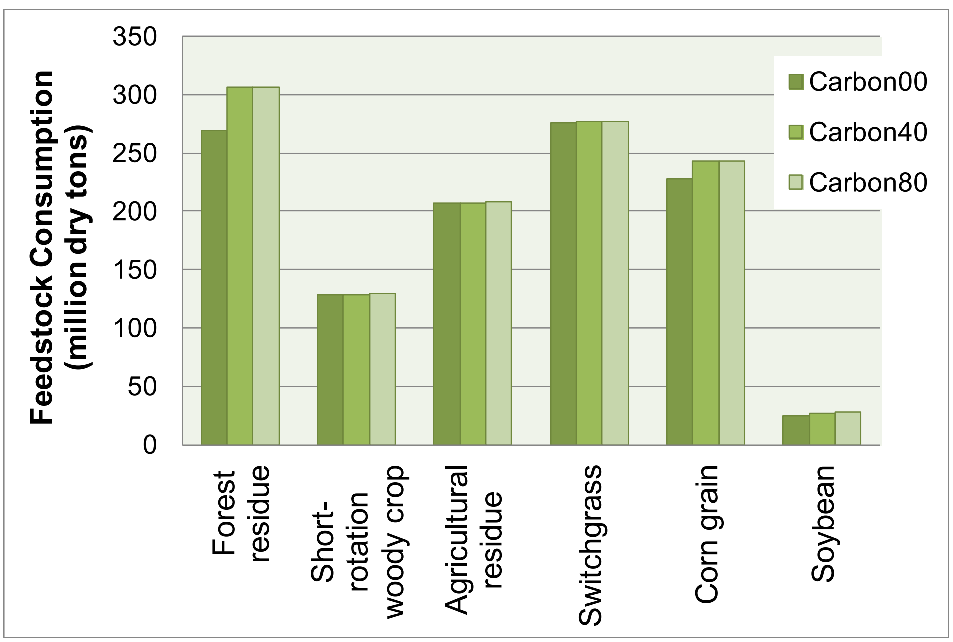


Figure 4.20. Biomass utilization by feedstock type in the hypothetical mature 2050 fuel markets with varied costs of carbon

The amount of SRWC, agricultural residues, and switchgrass utilized in the 2020 case does not increase when a cost of carbon is applied. Likewise, the quantities of all four classes of lignocellulosic feedstocks in the 2050 case are essentially constant. Utilization of those feedstocks does not increase because they cannot – the total supply is being used. Figure 4.21. shows the location on the supply curves for the four classes of lignocellulosic biomass, corn, and soybeans in 2020. The orange shapes indicate the point on the supply curve for each carbon cost case. The one on the lower left is for a cost of carbon of \$0/metric ton CO_2e, the middle is for \$40/metric ton CO_2e, and the one on the right is for \$80/metric ton CO_2e. Points on the dashed line are beyond the limits of the supply curve. In other words, consumers are projected to pay more than necessary to purchase that biomass because the market is likely to handle the higher prices. Ideally, the dashed lines are vertical; however, some slope is necessary for the BASE model to converge on a solution.

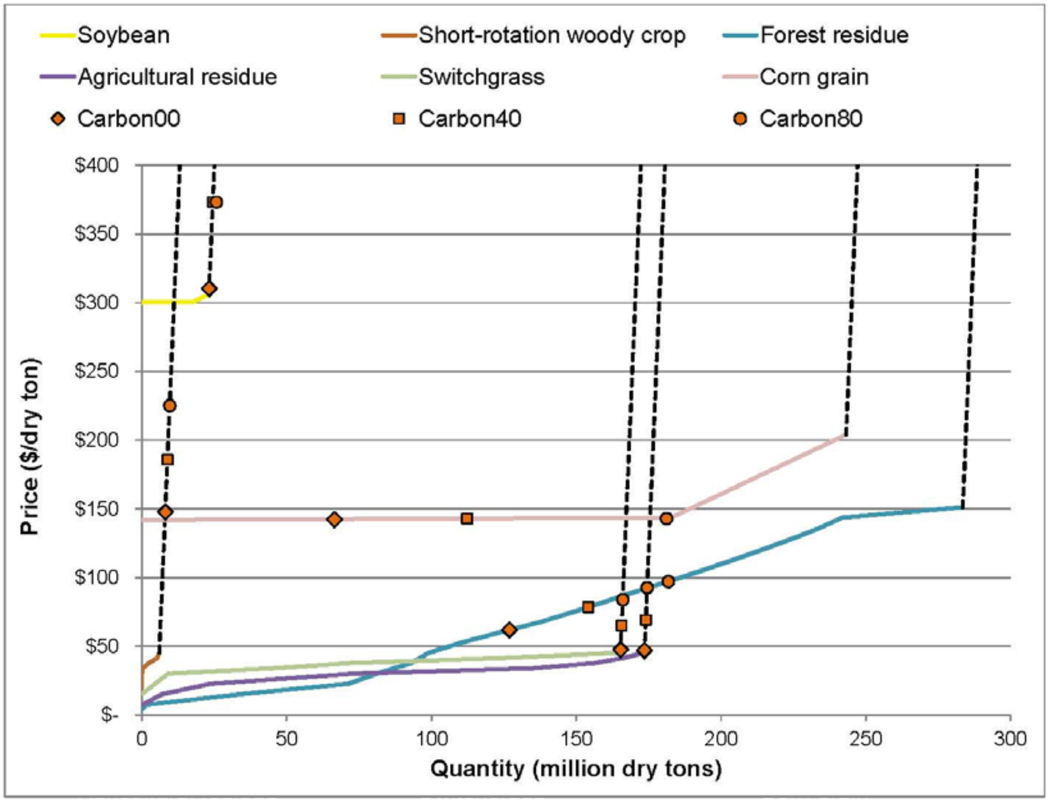


Figure 4.21. Feedstock supply curves in 2020 with indicators showing quantity consumed and price

(No cost of carbon, \$40/metric ton CO_2e cost of carbon, and \$80/metric ton CO_2e cost of carbon. Note that the quantity consumed for soybeans is the same for a \$40/metric ton CO_2e cost of carbon and an \$80/metric ton CO_2e cost of carbon.)

GHG emissions are important considerations. Emissions from each pathway are reported in the discussion of input data above, with the hypothetical fuel and electricity markets shown in Figure 4.22. Emissions from the sum of the gasoline, diesel, jet, and bunker fuel markets are only reduced by 1% with a \$40/metric ton CO_2e cost of carbon and by 3% with an \$80/metric ton CO_2e cost of carbon. The minimal reduction is due to a high penetration of biofuels with low-carbon emissions, and the fact that oil-based fuels have relatively low emissions when compared to coal-based electricity. However, the comparison of fuels markets without a biofuels option and one with biofuels shows that emissions are reduced by 10% when biofuels are available.

GHG emissions in the electric sector are reduced by 41% in the \$40/metric ton CO_2e cost of carbon scenario and by 61% in the \$80/metric ton CO_2e cost of carbon scenario. Those reductions are due to increased market share for nuclear, other RE, and variable renewable energy as reported above. Figure 4.23 shows the hypothetical mature 2020 market emissions due to each generation technology. Emissions from coal and natural gas drop due to decreased use of those technologies, and emissions from nuclear and non-biomass renewable sources increase due to higher utilization of those technologies. There are measurable emissions from nuclear and non-biomass technologies that are generated during manufacturing, construction, and decommissioning, as well as from uranium mining and enrichment.

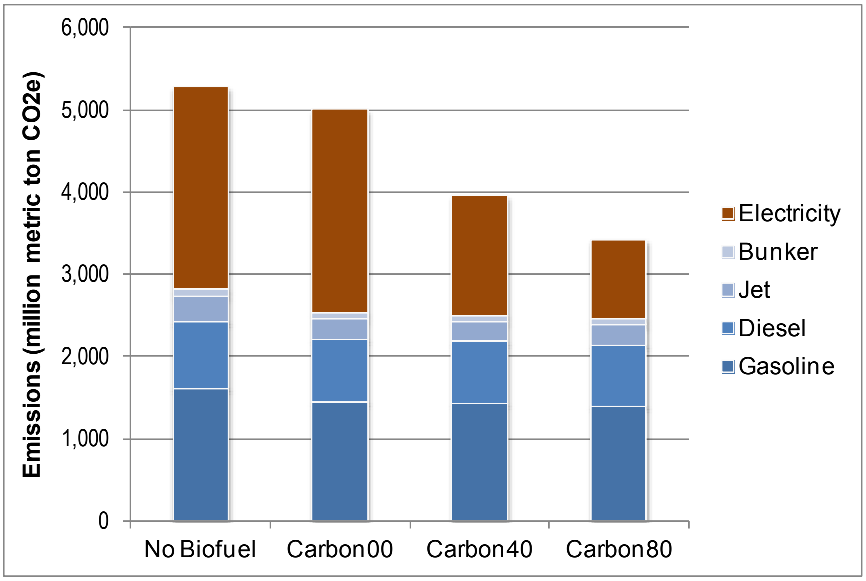


Figure 4.22. Total emissions by sector in hypothetical mature 2020 markets with varied costs of carbon

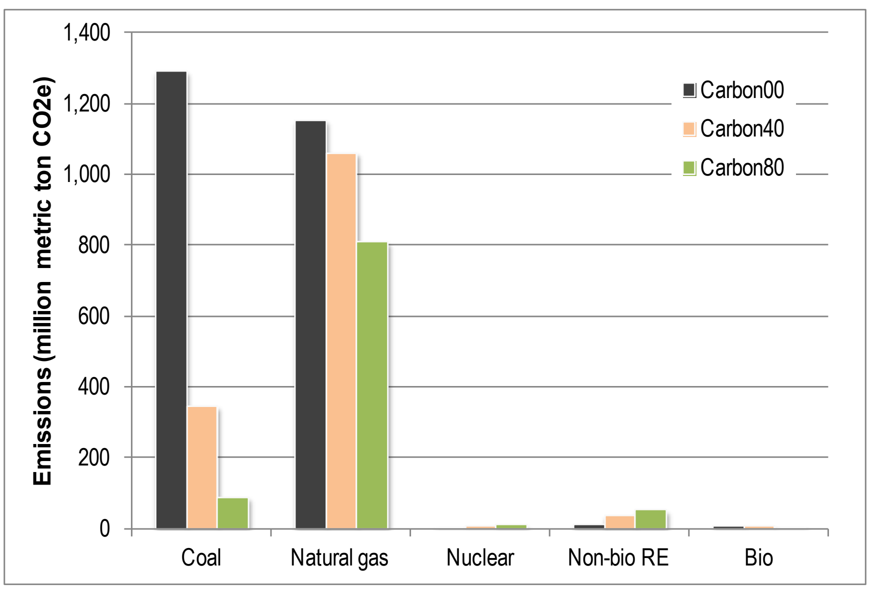


Figure 4.23. Annual electric sector emissions by sector in hypothetical mature 2020 markets with varied costs of carbon

Figures 4.24 and 4.25 report the same information as Figures 4.22 and 4.23, except for the hypothetical mature 2050 market. Emissions in the fuel markets are reduced by 4% with a \$40/metric ton CO_2e cost of carbon and by 8% with an \$80/metric ton CO_2e cost of carbon. Emissions are reduced by 26% in a market where biofuels are available versus where only petroleum-based fuels are offered. The emissions reduction in the 2050 market is greater than that in the 2020 market primarily because of the increased penetration of biofuels in the diesel market. Emissions in the electric sector are reduced by 50% in the \$40/metric ton CO_2e cost of carbon scenario and by 70% in the \$80/metric ton CO_2e cost of carbon scenario.

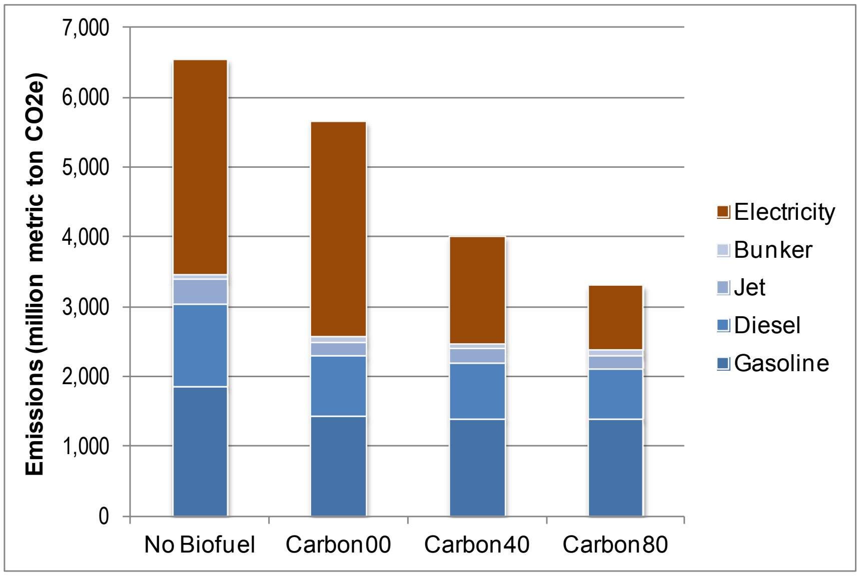


Figure 4.24. Total emissions by sector in hypothetical mature 2050 markets with varied costs of carbon

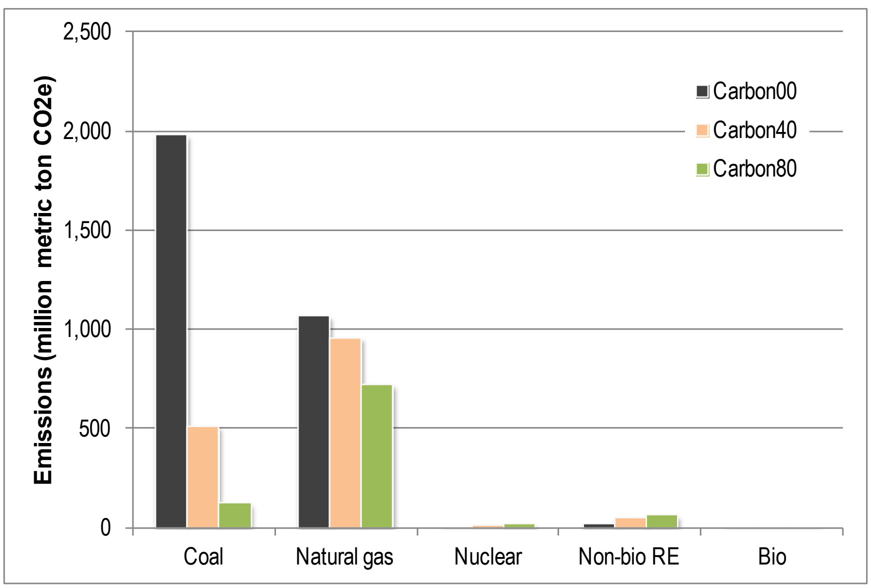


Figure 4.25. Annual electric sector emissions by sector in hypothetical mature 2050 markets with varied costs of carbon

Figures 4.26 and 4.27 display the WTW crude oil use in a hypothetical mature market in 2020. In Figure 4.27, the WTW petroleum consumption for conventional fuels is shown in the lower, darker bar. Reduction of conventional fuel demand (due to replacement with biofuels) reduces the lower, darker bar accordingly. Some petroleum is needed to produce the biofuel (e.g., for planting and harvesting) and that demand is shown by the smaller, lighter bar. As shown in Section 3.11, less petroleum is needed when biofuels provide the same services than when conventional fuel provides those services. Thus, markets with a higher penetration of biofuels use less petroleum.

The availability of biofuels reduces crude oil use by 12%, from a market with conventional fuels only with no cost of carbon because, as shown in Figures 4.13 and 4.14, 33 and 102 gallons of fuel equivalent are replaced with biofuels in the 2020 and 2050 zero cost of carbon cases, respectively. The amount of biofuels in the market is limited by resources so they it increases to 45 and 120 with an $80/metric ton CO_2e cost of carbon. Thus, the 2020 WTW petroleum use reduction with an $80/metric ton CO_2e cost of carbon reduces petroleum use by 16% from the case with no biofuels. That result is only 4% greater than that with no cost of carbon. Compared to increasing the cost of carbon, biofuel availability has the greatest potential for reducing petroleum use. Increasing the cost of carbon has a much smaller effect.

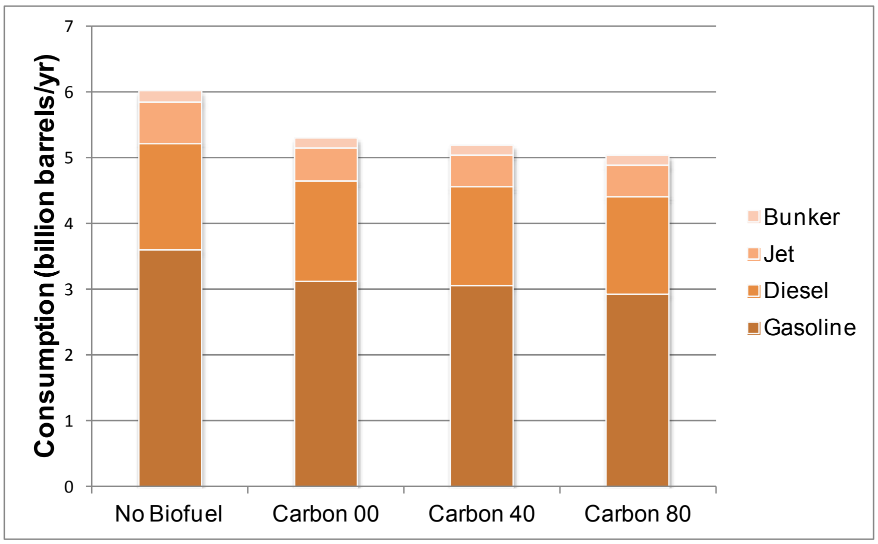


Figure 4.26. Annual WTW petroleum use by market in hypothetical mature 2020 markets with varied costs of carbon

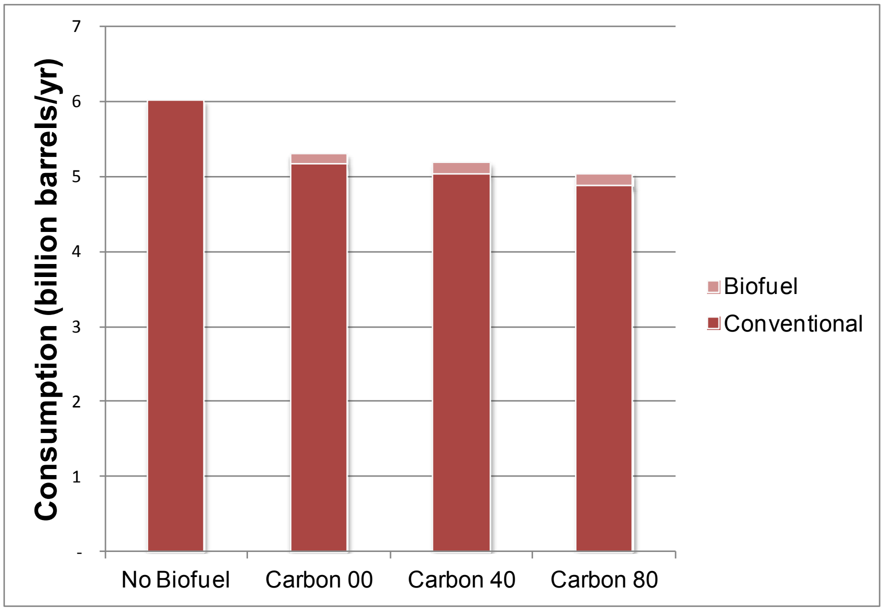


Figure 4.27. Annual WTW petroleum use by fuel genesis in hypothetical mature 2020 markets with varied costs of carbon

Figures 4.28 and 4.29 display the WTW crude oil use in a hypothetical mature market in 2050. The availability of biofuels reduces crude oil use by 30% from a market with conventional fuels only with no cost of carbon and by 35% with an $80/metric ton CO_2e cost of carbon. If conventional fuels were replaced by fuels with no petroleum use on a WTW basis, the reduction would be 35% (zero cost of carbon). Because our life cycle calculations include petroleum fuels for biomass farming and transport, biofuels require some petroleum and the reduction is only 30% (zero cost of carbon).

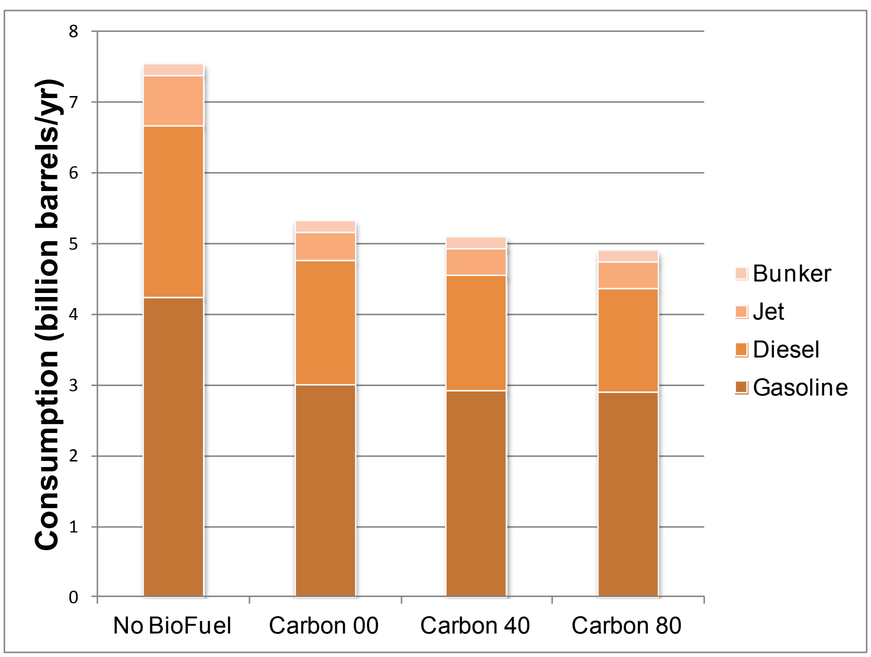


Figure 4.28. Annual WTW petroleum use by market in hypothetical mature 2050 markets with varied costs of carbon

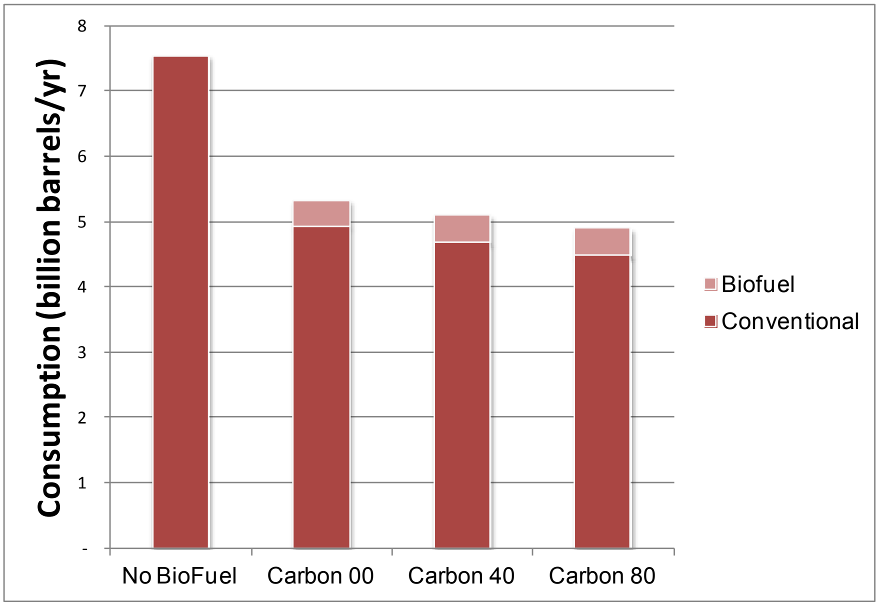


Figure 4.29. Annual WTW petroleum use by fuel genesis in hypothetical mature 2050 markets with varied costs of carbon

5. Sensitivity Results and Implications

In this study, sensitivities were performed by adjusting parameters in the default cases to better understand drivers that affect biomass penetration and segmentation in the fuel and electricity markets. This section describes how the use of these sensitivities can help determine the market appeal of biopower, the effect of failed technology development on biofuels penetration, and the impacts of biomass feedstock and conventional resource pricing.

5.1 Improved Opportunities for Biopower

The BASE model indicates that the most economical use of biomass is for transportation, not power. One potential reason for this is that the default assumptions for biopower are less optimistic than those of biofuels. To test that possibility, several sensitivities were performed. Capital costs could be lower in the near term because, in electricity generation facilities where biomass is co-fired with coal, much of the capital has already been paid off during the early, coal-combusting part of the plant's lifetime. In the long term, co-firing does not reduce capital cost, because capital costs must be annuitized over the biomass portion of the plant as well as the coal portion. As a result, those costs must be included in analyses such as this one and the initial assumptions used for the 2050 case are valid. Thus, a sensitivity involving reducing the overnight capital cost for biopower by 30% was performed only for the hypothetical mature 2020 market.

Figure 5.1 displays the effect that reducing capital costs has on the amount of biomass utilized in each energy market (with \$0, \$40, and \$80/metric ton CO_2e costs of carbon), and Figure 5.2 shows the effect on the hypothetical power markets. Essentially, the same amount of biomass is used; however, there are small increases of use in the power sector with corresponding decreases in the fuels markets. The amount of biomass used for power doubles in the \$0/metric ton CO_2e cost of carbon scenario with smaller increases in the scenarios with carbon costs only. That increase boosts the biopower share of the electricity market from about 0.4%-0.9% in the zero carbon cost case; however, the total share is still negligible. In all scenarios, the amount of biomass used for transportation is reduced by 3% or less.

This sensitivity indicates that either the capital costs for biopower must be more than 30% lower—or costs of competing low-carbon generation must be higher—or the conversion costs from biomass to fuels must be much higher to drive biomass to the power sector. The most likely reason for this is that there are other options available for low-cost and low-carbon electricity, but there are few other options for transportation.

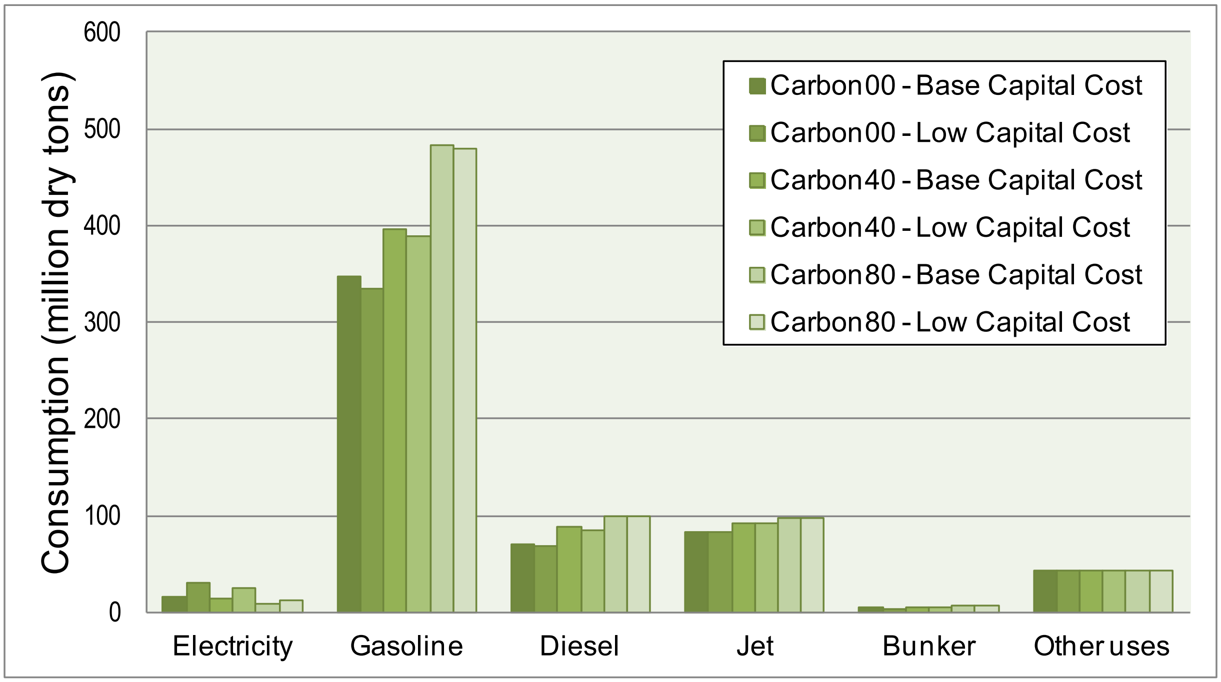


Figure 5.1. Effects of reduced biopower capital costs on biomass utilization in each hypothetical mature 2020 market with varied costs of carbon

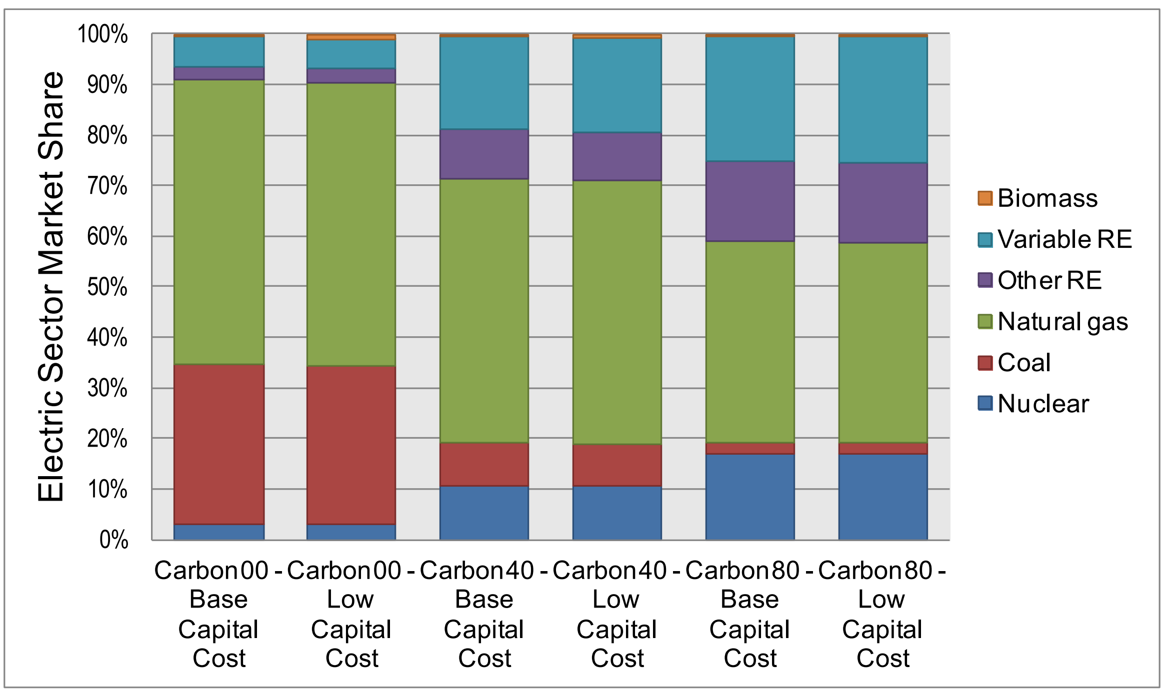


Figure 5.2. Effects of reduced biopower capital costs on biopower penetration in hypothetical mature 2020 markets with varied costs of carbon

Another possible biopower assumption that could be too pessimistic is that the heat rate is too high. In other words, R&D might be able to make the biopower process more efficient, with less biomass needed to generate a given amount of power. To test that possibility, researchers used a reduced biopower heat rate sensitivity. This improvement requires R&D and is most likely to apply in the long term, so, only the 2050 case is reported. To perform the analysis, the biopower heat rate was reduced by 30%.

Figures 5.3 and 5.4 show that, by reducing the heat rate, the use of biomass for power essentially tripled. Still, even with the decreased heat rate, biopower only has a negligible share of the projected electricity market. Note that a smaller fraction of the electricity market is biopower in 2050 than in 2020, due to assumed improvements to other technologies. The amount of biomass projected to be used for power is so small that the increases have a negligible effect on the fuel market.

This sensitivity indicates that, without other drivers, dramatic improvements to the biomass-to-power conversion efficiency are insufficient to pull biomass into the power market. Those potential drivers could include difficulty in achieving projected improvements in the fuel conversion processes or other power-generation technologies, or CCS availability.

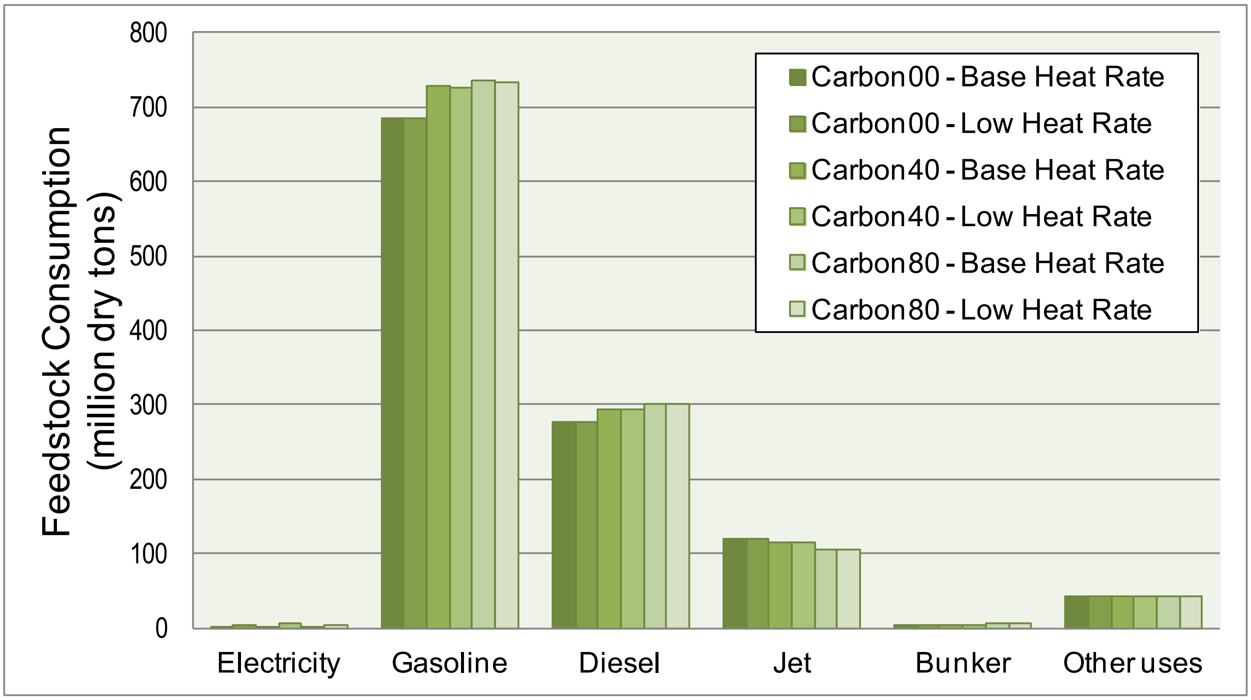


Figure 5.3. Effects of reduced heat rates on biomass utilization in each hypothetical mature 2050 fuel market with varied costs of carbon

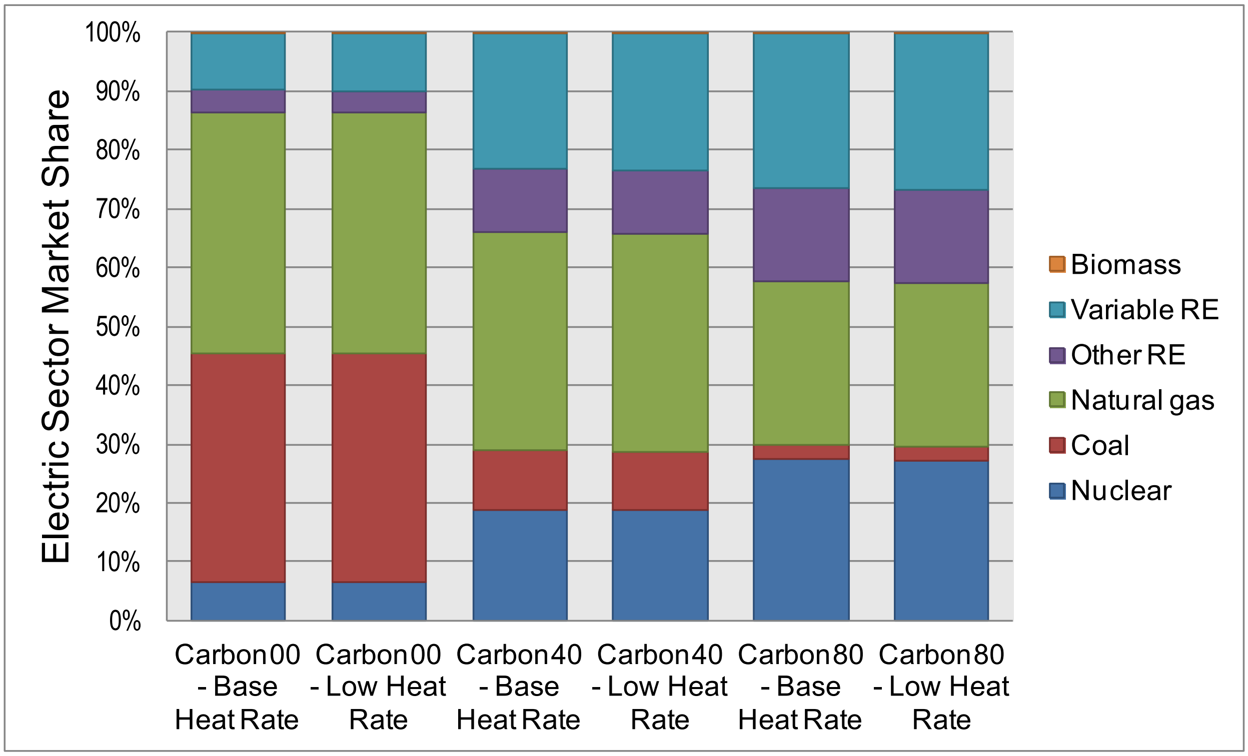


Figure 5.4. Effects of reduced heat rates on biopower penetration in hypothetical mature 2050 markets with varied costs of carbon

A third possible biopower assumption that could be too pessimistic is that CCS is not available. CCS parameters were added to all applicable power generation technologies to test their effects on biomass use. Note that this case only has power production options with CCS. The current version of the BASE model does not allow for competition between power-generation with CCS and power-generation without it, so the CCS sensitivity is included for the entire share of each applicable technology. Because the required technology is unlikely to be widely available by 2020, only the CCS sensitivity for 2050 was analyzed. In addition, it was not included as an option for transportation fuel technologies due to a lack of data. By excluding that option for transportation fuel, the probability of using biomass in the power sector goes up. As a result, this sensitivity can be considered an extreme (i.e., most favorable for biopower).

The effects of CCS on power generation capital, operating costs, and heat rates are shown in Table 5.1. The technology cost and performance data for natural gas combined-cycle CCS (NG-CC-CCS) plants, coal-integrated gasification plants, and coal combined-cycle CCS (coal-IGCC-CCS) plants from *Annual Energy Outlook 2011* were used. Since *Annual Energy Outlook 2011* did not include biopower with CCS (bio-CCS) options, overnight capital costs for bio-CCS were assumed to be increases of the standard biopower capital costs (Table 3.9 by the difference between coal-IGCC-CCS (Table 5.1) and pulverized coal ("Coal" in Table 3.9). Operation and maintenance (O&M) costs and heat rates for bio-CCS were assumed to be the same as those shown in Table 3.9 for biopower. Table 5.1 summarizes the technology cost and performance assumptions for the CCS technologies used in these scenarios.

Emissions data used in BASE are reported in Appendix G. Because GHG emissions from CCS technologies are speculative and have large ranges, values were selected based on best available data.

Table 5.1. 2050 Cost and Performance Data for CCS Generation Technologies (2005$)

(Data sources referenced in text.)

Technology	Capital net commodity index ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (10^6Btu/MWh)
Coal-IGCC-CCS	$3051	$62.47	$8.06	8.307
NG-IGCC-CCS	$1134	$27.27	$5.81	7.493
Bio-CCS	$4111	$90.60	$5.41	13.50

Figure 5.5 shows that biopower's share of the electricity market stays below 1% in the $0/metric ton CO_2e cost of carbon scenario but, due to the availability of CCS, increases to 2% of the electricity market with a $40/metric ton CO_2e cost of carbon and over 13% of the market with an $80/metric ton CO_2e cost of carbon. Figure 5.6 shows the corresponding use of biomass for power. It goes up to 90 short ton/yr of biomass for power in the $40/metric ton CO_2e cost of carbon scenario and to 590 short ton/yr in the $80/metric ton CO_2e cost of carbon scenario because the value proposition in that scenario leads to negative costs for biopower. The figure also shows that, due to resource limitations, using biomass for power generation reduces the amount of feedstock available for transportation fuels. When CCS is used and the cost of carbon is $80/metric ton CO_2e, the amount of biomass available for transportation fuel is reduced to 570 short ton/yr.

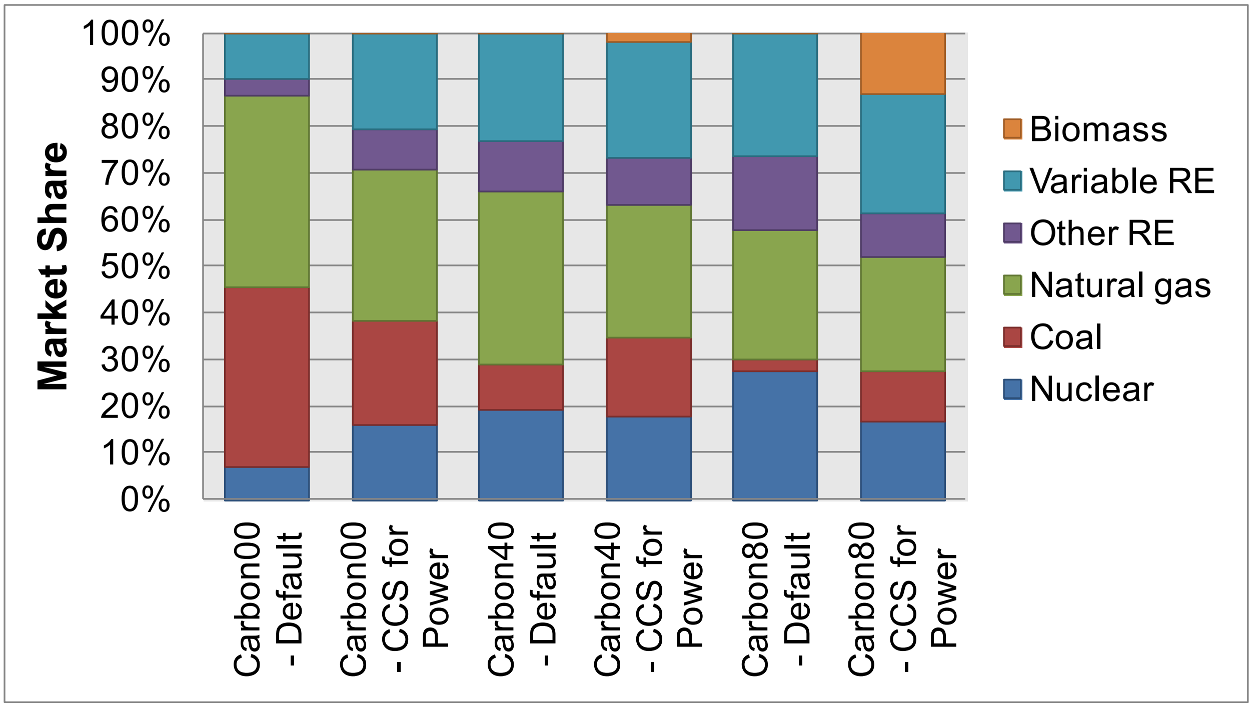


Figure 5.5. Effects of CCS availability on biopower penetration in hypothetical mature 2050 markets with varied costs of carbon

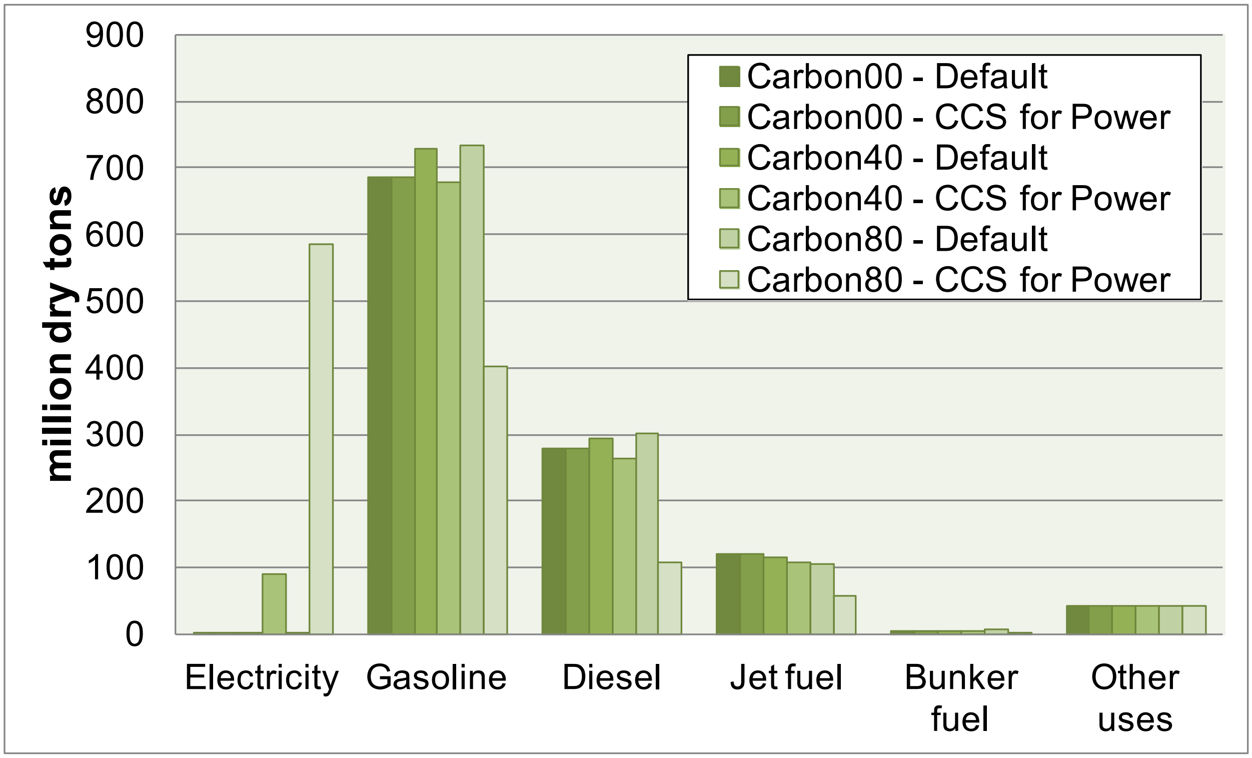


Figure 5.6. Effects of CCS availability on biomass utilization in each hypothetical mature 2050 fuel market with varied costs of carbon

Figure 5.7 shows that pyrolysis gasoline and diesel experience the greatest reductions in scenarios where biomass is used for power. A large fraction of the ethanol and butanol in the gasoline market is based on corn grain, so it is not reduced by other uses of lignocellulosic biomass. Pyrolysis gasoline and diesel have larger market shares than other fuels from the lignocellulosic biomass options so they take the largest hits.

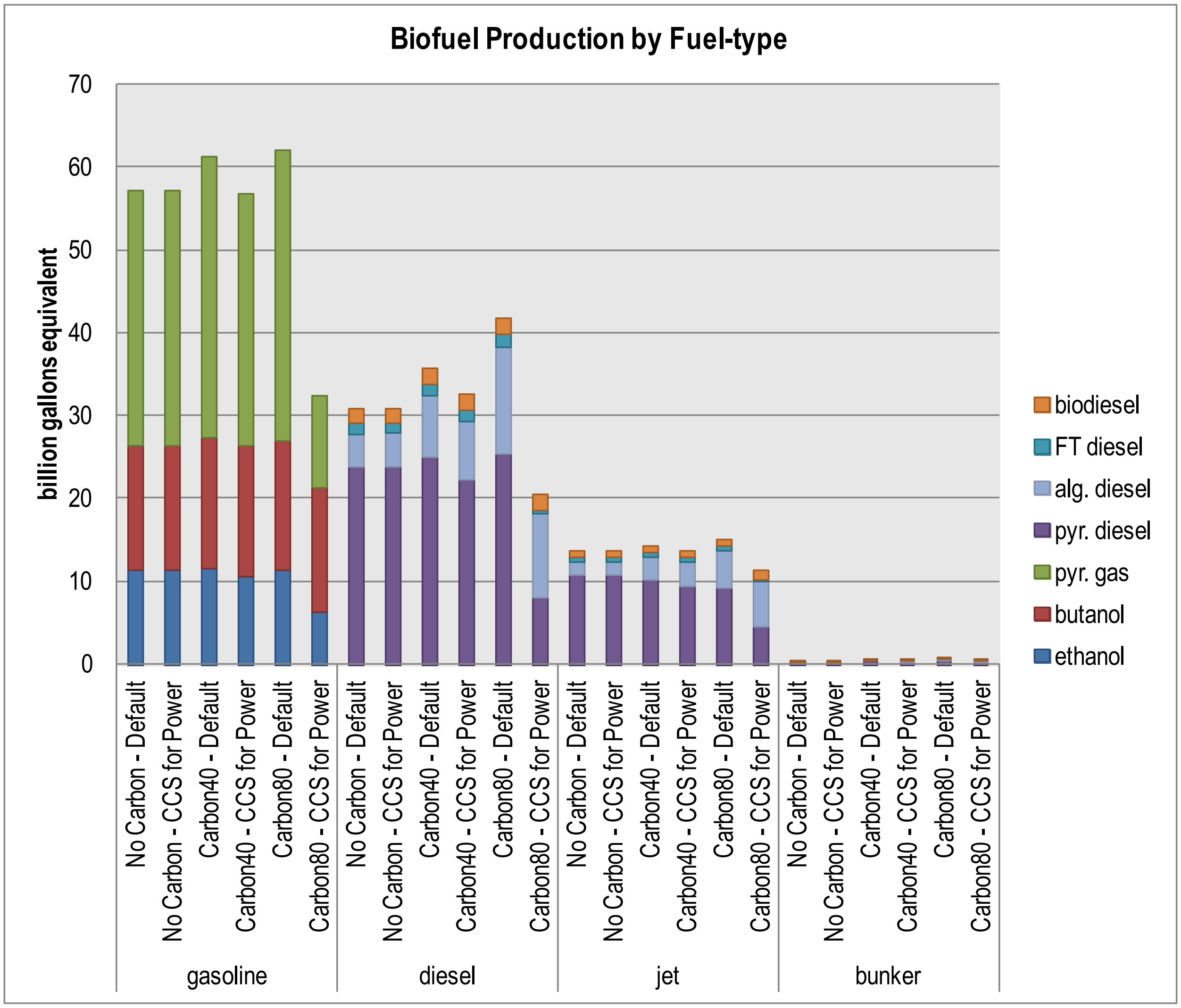


Figure 5.7. Effects of CCS availability on biofuel production by fuel type in hypothetical mature 2050 markets with varied costs of carbon

Figure 5.8 shows the effect on annual GHG emissions when using CCS for power. Converting the power sector from one without CCS to one with CCS (i.e., power production options without CCS were removed and replaced by those with CCS) reduces the electric sector's emissions from over 3 billion metric tons CO_2e annually to about 2 billion metric tons CO_2e/yr even without a cost of carbon. As shown above, having a cost of carbon of $40/metric ton CO_2e increases the use of biopower due to its negative overall GHG emissions when CCS is included. The resulting increase in biopower and its negative emissions result in reduced power sector emissions to less than 1.4 billion metric tons CO_2e/yr.

At $80/metric ton CO_2e cost of carbon, biopower penetrates sufficiently for the power sector to have negative emissions. Overall, the carbon emissions are reduced from over 5.8 billion metric tons CO_2e annually in the default scenario (without CCS and with no cost of carbon) to 2.9 billion metric tons CO_2e emitted annually in the scenario with CCS and an $80/metric ton CO_2e cost of carbon.

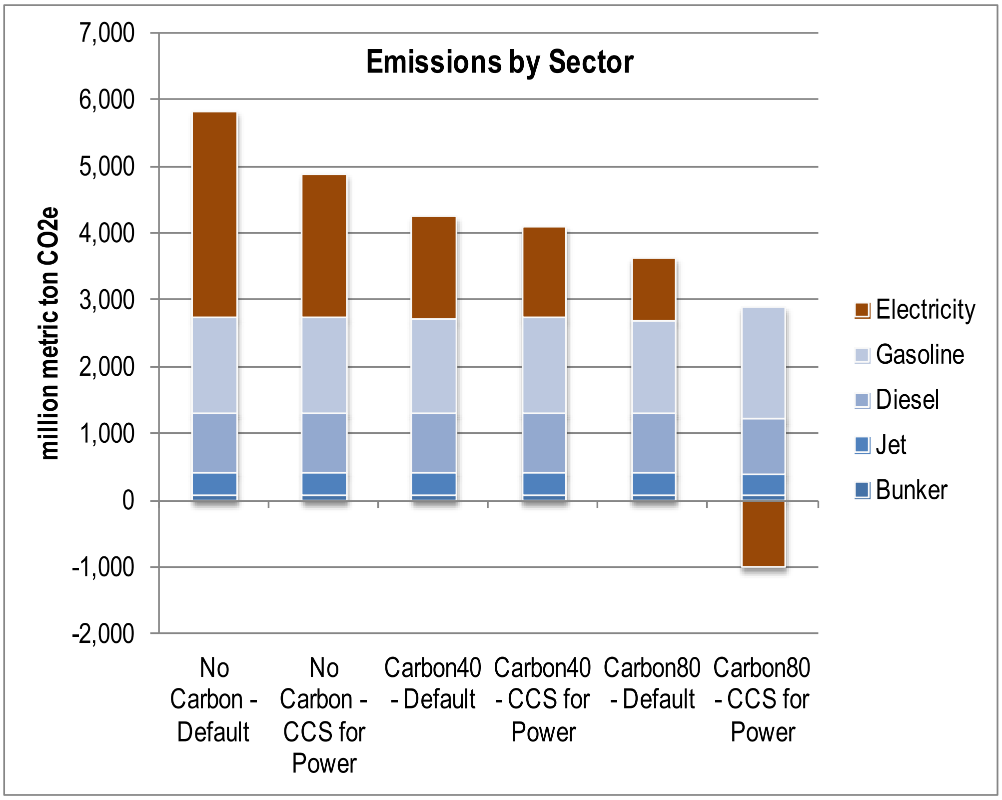


Figure 5.8. Effects of CCS availability on carbon emissions in hypothetical mature 2050 markets with varied costs of carbon

Figure 5.9 shows the effect on annual petroleum use when CCS is employed for power. As expected, using biomass for power increases the consumption of petroleum. If no biofuels are used for transportation, the 2050 projection of petroleum use is 7.5 billion barrels per year. The default scenario without a cost of carbon reduces that demand to 5.3 billion barrels annually with costs of carbon further reducing the use of oil. However, use of large quantities of biomass for power negates that reduction as is shown in the case where CCS is available and the cost of carbon is $80/metric ton CO_2e. Although there is potential for biomass in the power sector, and the ability to reduce GHG emissions by combining it with CCS and high costs of carbon, biopower has limited ability to reduce petroleum use without adjusting the model to allow for additional vehicle electrification. Recall that the market sizes for each fuel and electricity are based on projections with limited vehicle electrification; increasing vehicle electrification will increase the size of the hydrogen and/or electricity markets and reduce petroleum use. Those changes to market size are outside the scope of this analysis.

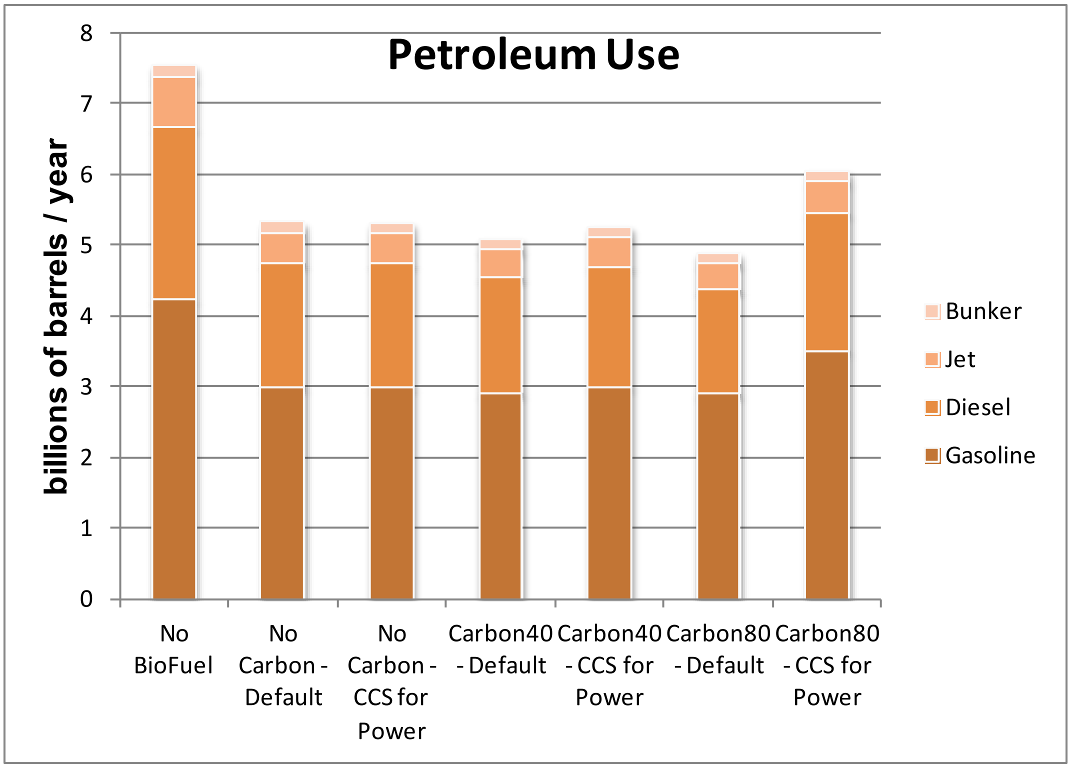


Figure 5.9. Effects of CCS availability on WTW petroleum use in hypothetical mature 2050 markets with varied costs of carbon

5.2 Failure of Conversion Technology Development

This analysis assumes technology improvements based on R&D. As with all R&D, results are not guaranteed. As a result, the default conversion parameters are not known absolutely, and variations will affect market share. Pyrolysis gasoline and diesel/jet fuel/bunker fuel require over 650 million short tons of lignocellulosic biomass to meet market equilibrium in 2050 with the default parameters. That is the majority of the lignocellulosic biomass, so failure of R&D for that technology (eliminating it as a possibility within the BASE model) is likely to have the greatest effect on biomass utilization.

Figure 5.10 shows that, without pyrolysis as a technology option, the utilization of biomass in 2050 is only reduced slightly. With no cost of carbon, the amount of lignocellulosic biomass utilized goes down by 56 million dry short tons/yr from a total use of 880 million dry short tons/yr; therefore, the 655 million dry short tons of biomass that was projected to be used for pyrolysis is being used elsewhere.

Instead of being used to produce pyrolysis gasoline and diesel, the lignocellulosic biomass is used to produce ethanol and butanol for the gasoline market (shown in Figure 5.11). It is not used for Fischer-Tropsch diesel, because ethanol and butanol are more profitable. Due to the fuel selection, the biofuel penetration in the gasoline market increases by almost 12% in the zero cost of carbon scenario. Biofuel penetration drops dramatically in the diesel and jet markets—by 91% in the diesel market and by 61% in the jet fuel market. The loss is greater in the diesel market, because the market price is higher in the jet fuel market, so profits are higher. In addition, the amount of biomass used for electricity almost triples due to increased availability (not shown).

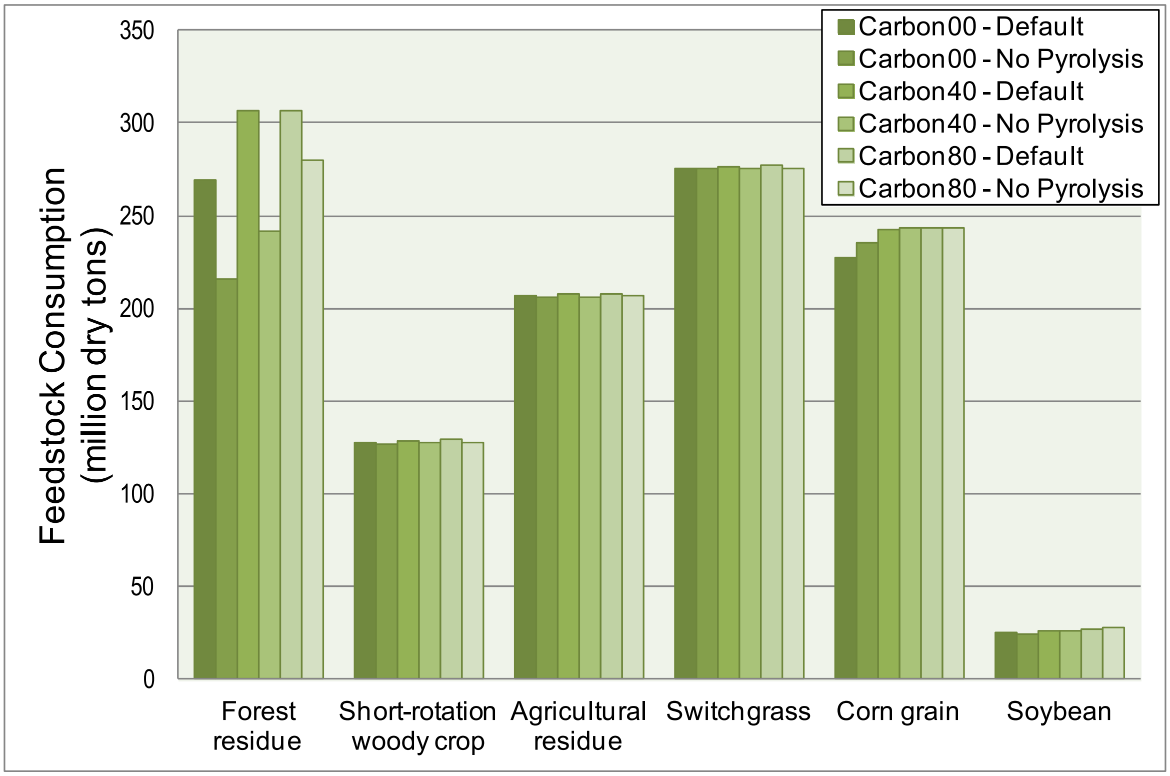


Figure 5.10. Effects of pyrolysis R&D failure on biomass utilization by feedstock type in hypothetical mature 2050 markets with varied costs of carbon

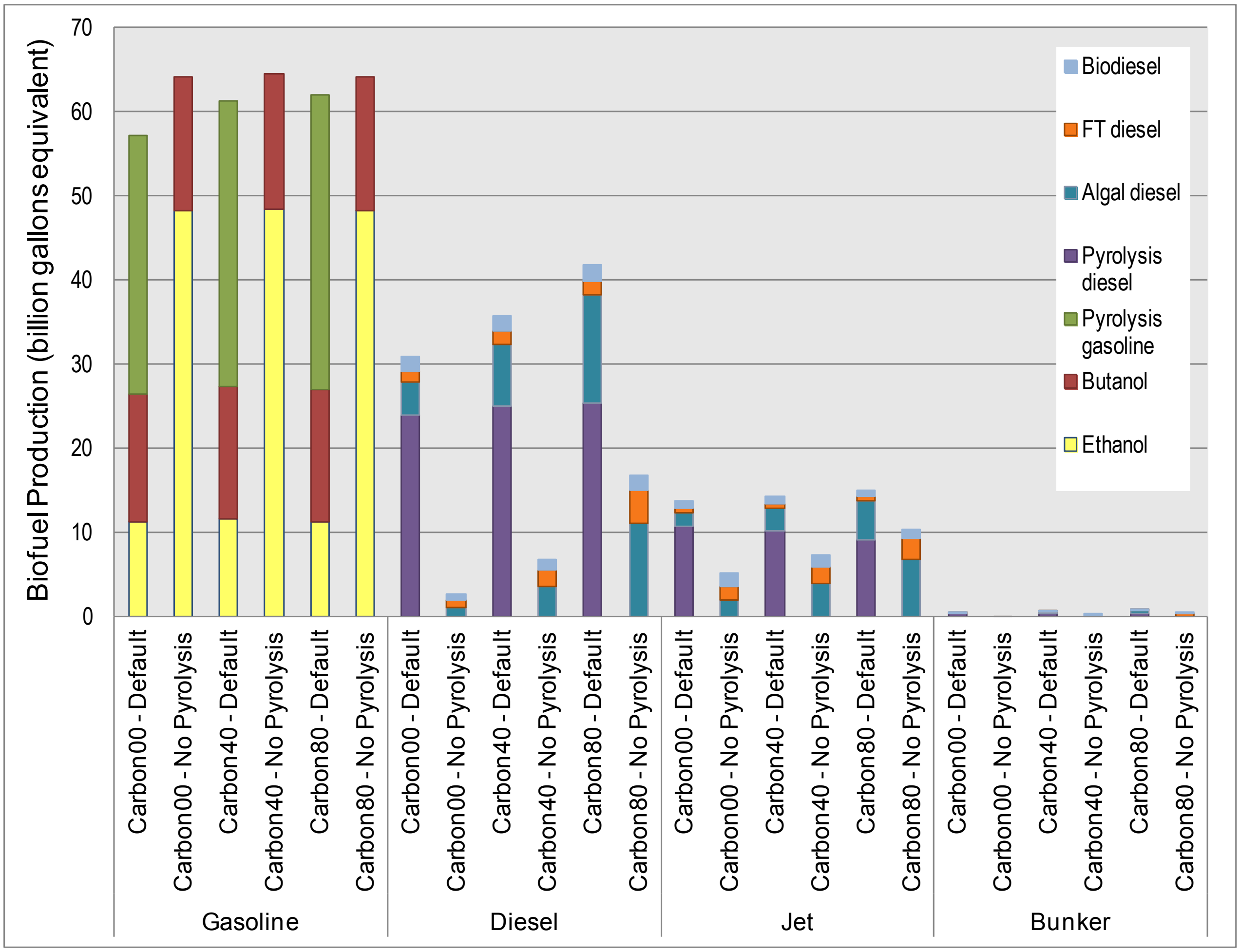


Figure 5.11. Effects of pyrolysis R&D failure on biomass utilization in each hypothetical mature 2050 fuel market by fuel type with varied costs of carbon

Figures 5.12 and 5.13 show how GHG emissions and petroleum use are affected without pyrolysis. In the scenarios with no cost of carbon, the lack of pyrolysis increases both GHG emissions and petroleum use by 12% over the scenario where pyrolysis is available.

Failure in one technology's development redistributes biomass demand to other areas.

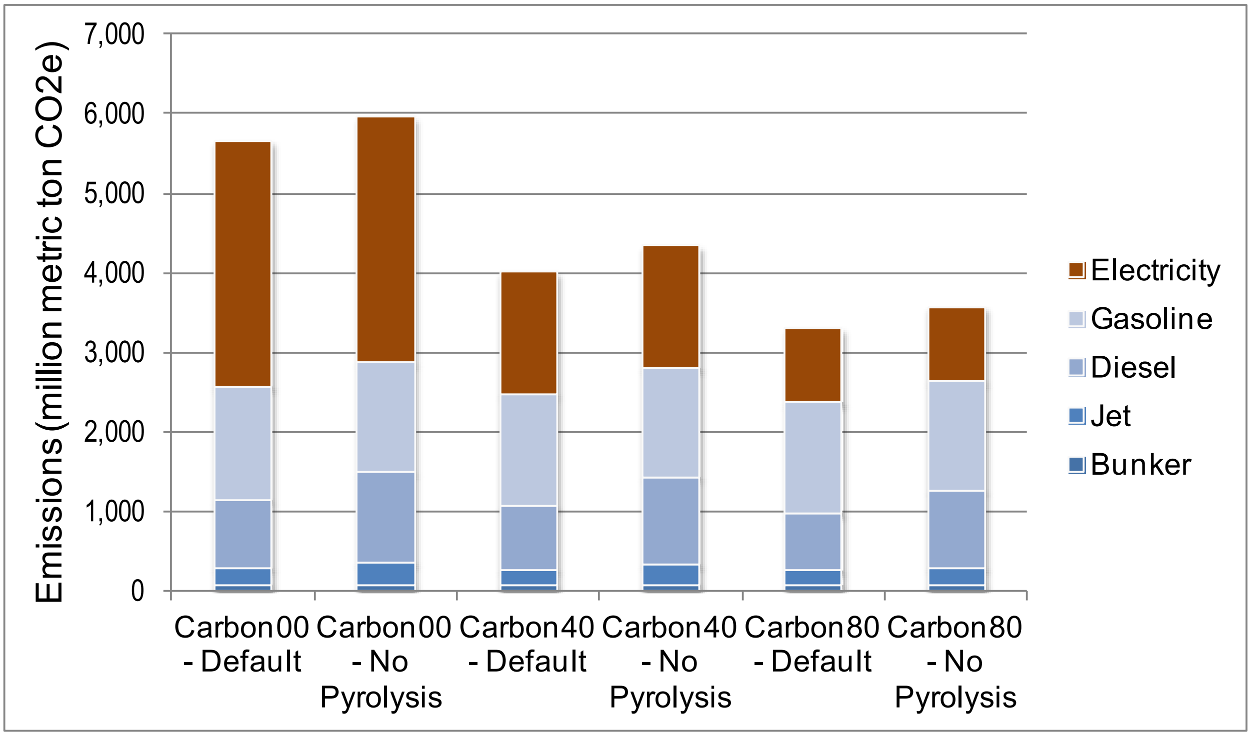


Figure 5.12. Effects of pyrolysis R&D failure on carbon emissions in hypothetical mature 2050 markets with varied costs of carbon

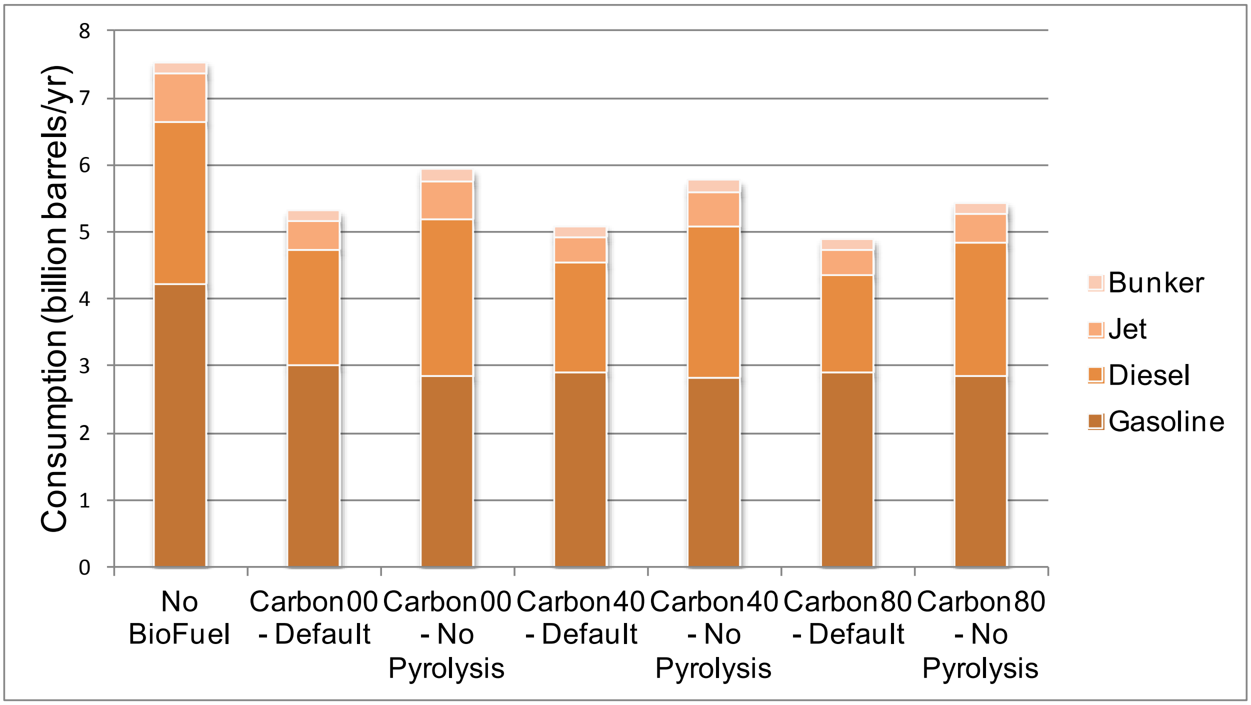


Figure 5.13. Effects of pyrolysis R&D failure on WTW petroleum use in hypothetical mature 2050 markets with varied costs of carbon

5.3 Feedstock Cost Sensitivities

Like technology, market prices are also uncertain and variable. The default price projections used for corn and soybeans in 2020 were based on FAPRI's 2019 price projections of $3.60/bushel (bu) for corn and $8.60/bu for soybeans. Specifically, in Iowa, August 2011 prices were $6.84/bu for corn and $13.50/bu for soybeans (Iowa State University and Iowa Agricultural Statistics 2011). In the sensitivity, the base price for the corn supply curve was increased from $143/dry short ton to $186/dry short ton (2005$), and the base price for the soybeans was increased from $300/dry short ton to $390/dry short ton (2005$).

Figure 5.14 indicates that higher prices reduce the amount of corn and soy used for biofuels. With no cost of carbon, corn utilization is reduced by 45 million short tons per year, or 70%, and soy is reduced by 15 million short tons/yr, or 60%. The amount of SRWC, agricultural residue, and switchgrass did not increase, because those resources were already fully utilized. The amount of forest residue utilized increased slightly, but experienced a greater effect when the cost of carbon was increased. Figure 5.15 shows that biofuel penetration in gasoline, diesel, and jet fuel markets was reduced, because the markets were no longer able to afford as much corn and soybean at the higher prices. Biomass use for electricity was reduced by about 14% at no cost of carbon, because that biomass could be used more economically for liquid fuels. The resulting decrease in biopower market share was from 0.43% to 0.37%. Figures 5.16 and 5.17 show that GHG emissions from liquid fuels increased by 1%, and petroleum use also increased by 1%, due to higher corn and soybean prices at no cost of carbon.

As expected, high corn and soybean prices adversely affect the quantity of fuels from market competitive feedstocks. Because most of the lignocellulosic feedstocks are already fully utilized in the hypothetical mature markets, only small increases in their utilization are possible. This seems to indicate that other markets for corn and soybeans, including food, feed, and products, are likely to use corn and soybeans, and that the difference will need to come from conventional fuels.

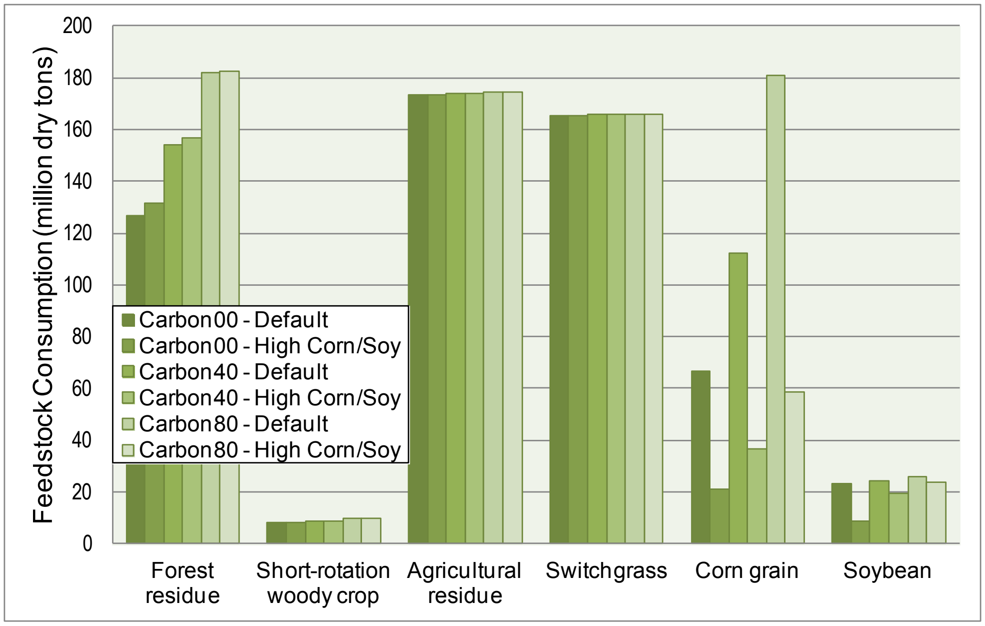


Figure 5.14. Effects of high prices for corn and soybeans on biomass utilization by feedstock type in hypothetical mature 2020 markets with varied costs of carbon

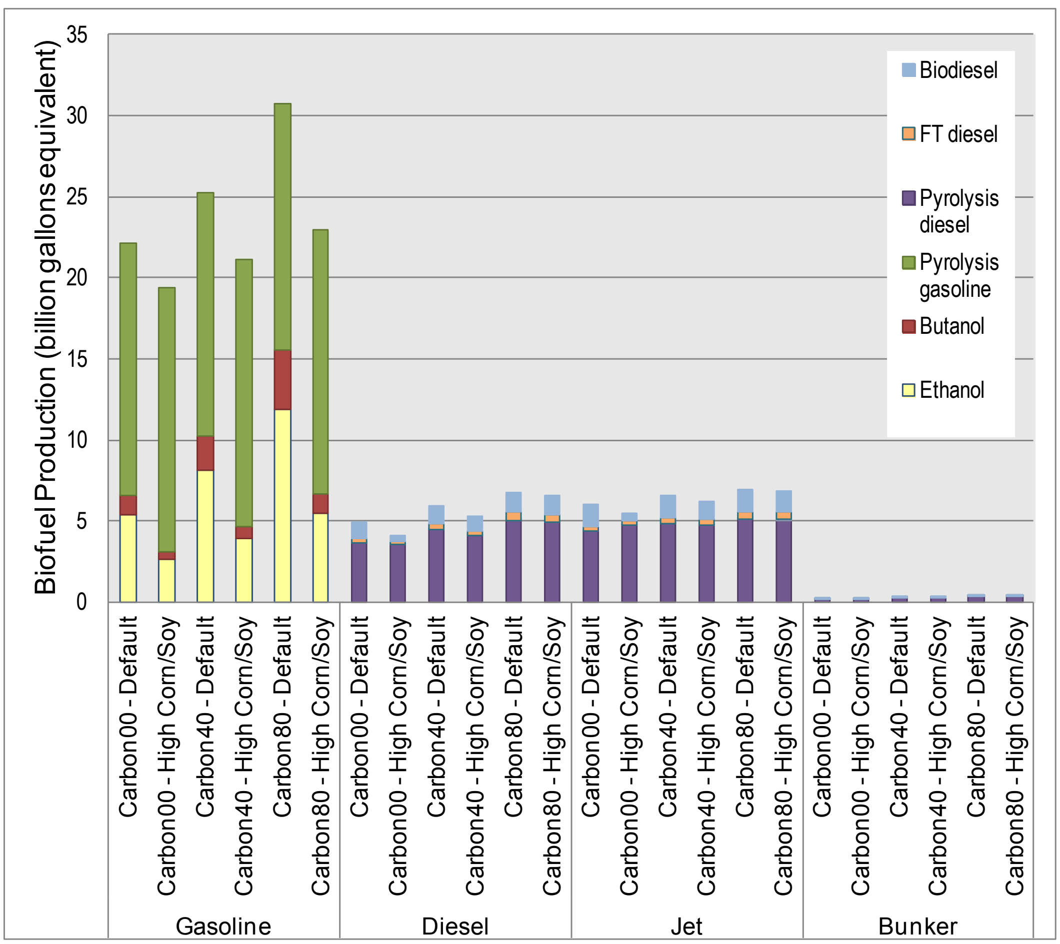


Figure 5.15. Effects of high prices for corn and soybeans on biomass utilization in each hypothetical mature 2020 fuel market with varied costs of carbon by fuel type

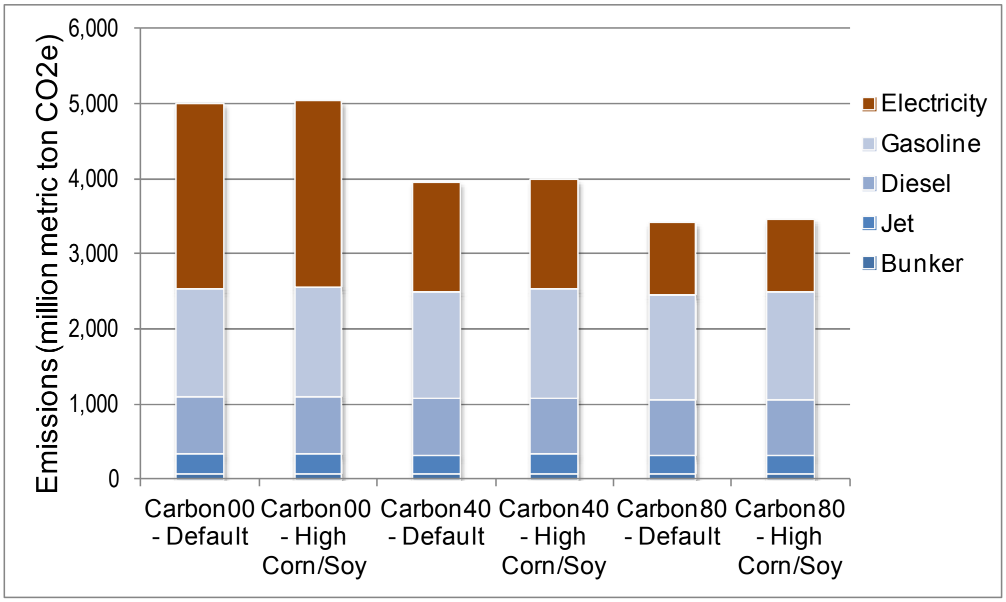


Figure 5.16. Effects of high prices for corn and soybeans on carbon emissions in hypothetical mature 2020 markets with varied costs of carbon

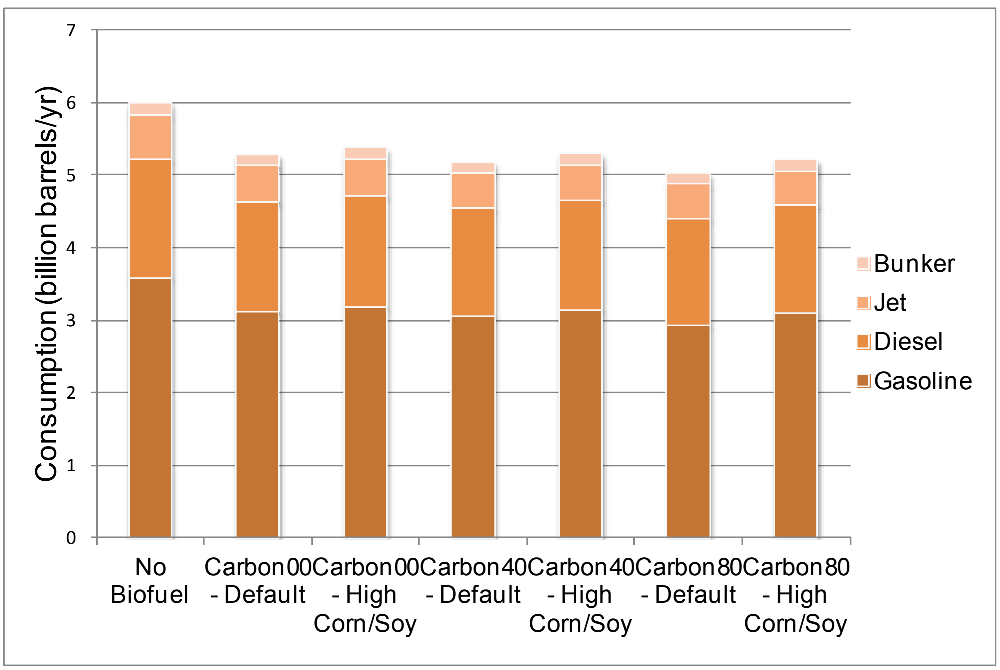


Figure 5.17. Effects of high prices for corn and soybeans on WTW petroleum use in hypothetical mature 2020 markets with varied costs of carbon

In addition to low default corn and soybean prices, projections for lignocellulosic biomass could be low, as well. Therefore, a sensitivity was run with higher prices for all the lignocellulosic feedstocks as well as the prices for corn and soybeans. The forest residue, SRWC, agricultural residue, and switchgrass prices for 2020 were all increased by 30% above the default across the whole of their supply curves. Corn and soybean prices were also increased, as described in the sensitivity above.

As shown in Figure 5.18, increasing the prices of lignocellulosic biomass reduces the biomass utilization at no cost of carbon. SRWC has the lowest price and therefore the least reduction [180,000 short ton/yr (2%)]. Agricultural residues had a greater reduction, at 12 million short ton/yr (7%), and forest residue still greater, at 14 million short tons/yr (11%). The greatest percent reduction was to switchgrass, at 28 million short tons/yr (17%). Figure 5.19 shows the effects of higher biomass prices on the fuel markets. Reductions to ethanol and butanol prices are beyond those seen with high corn and soybean prices only. As seen in the scenario with high corn and soybean prices, GHG emissions and petroleum use increase slightly, as well.

As feedstock prices rise, feedstock utilization declines, requiring conventional fuels to make up the difference.

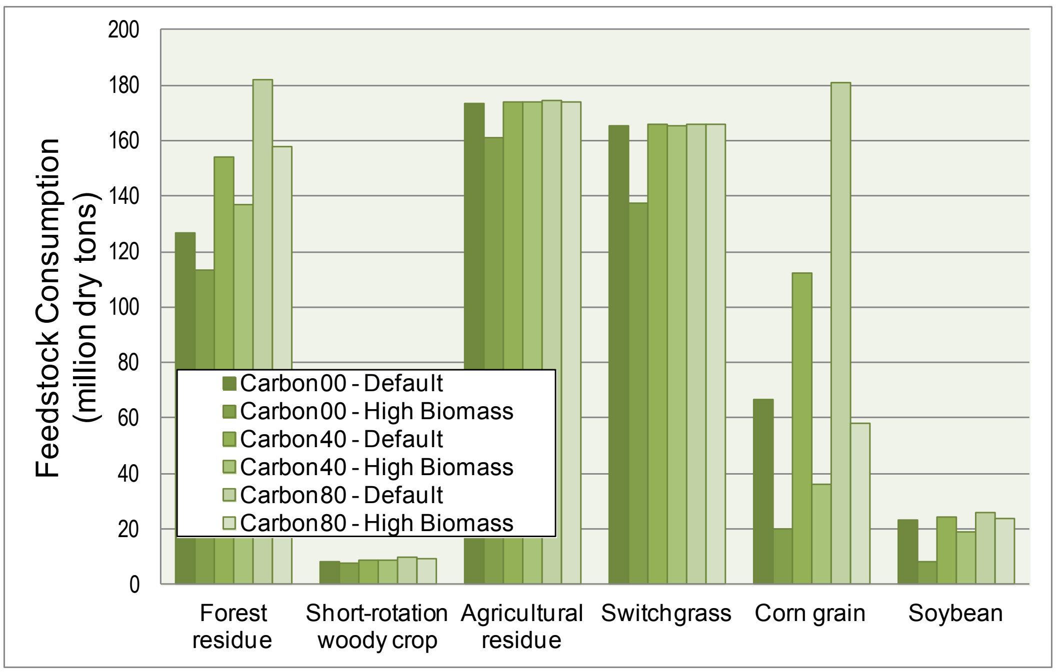


Figure 5.18. Effects of high lignocellulosic biomass prices on biomass utilization by feedstock type in hypothetical mature 2020 markets with varied costs of carbon

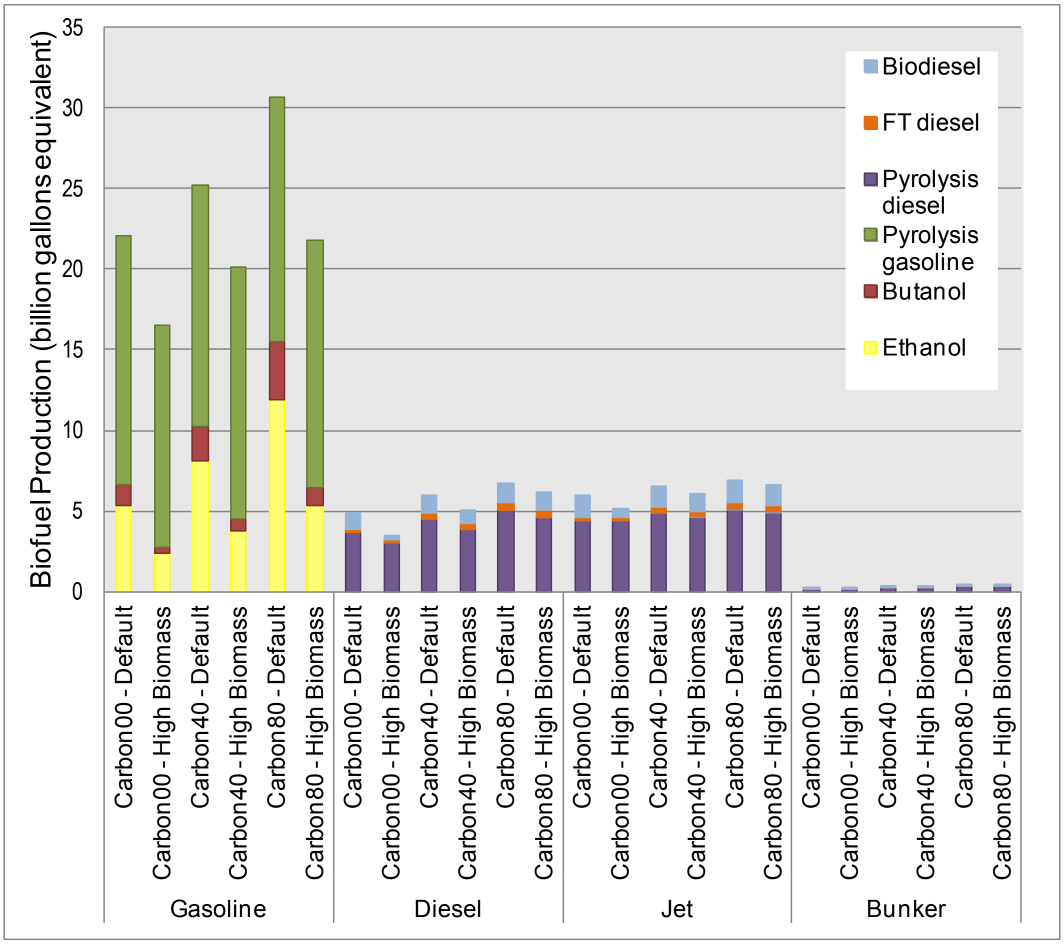


Figure 5.19. Effects of high lignocellulosic biomass prices on biomass utilization in each hypothetical mature 2020 fuel market by fuel type with varied costs of carbon

One might expect that by increasing the prices of only some biomass feedstocks, there will be an increase in the market penetration of other types of feedstocks. To test that hypothesis, the prices of switchgrass and agricultural residues were increased. These feedstocks were chosen because their maximum supply is utilized in the default parameter case with no cost of carbon. Like the sensitivity discussed above, agricultural residue and switchgrass prices were increased by 30% relative to the default supply curve.

Figure 5.20 shows the resulting effect on consumption of all the feedstocks. The higher price reduced the use of agricultural residue and switchgrass in the zero cost of carbon case. It did not increase the utilization of forest residue or other feedstocks. The price of the fuel did not increase by enough for forest residue to penetrate more fully, due to a lack of elasticity of the conventional fuels' prices (i.e., the share of conventional fuels increased but their price did not).

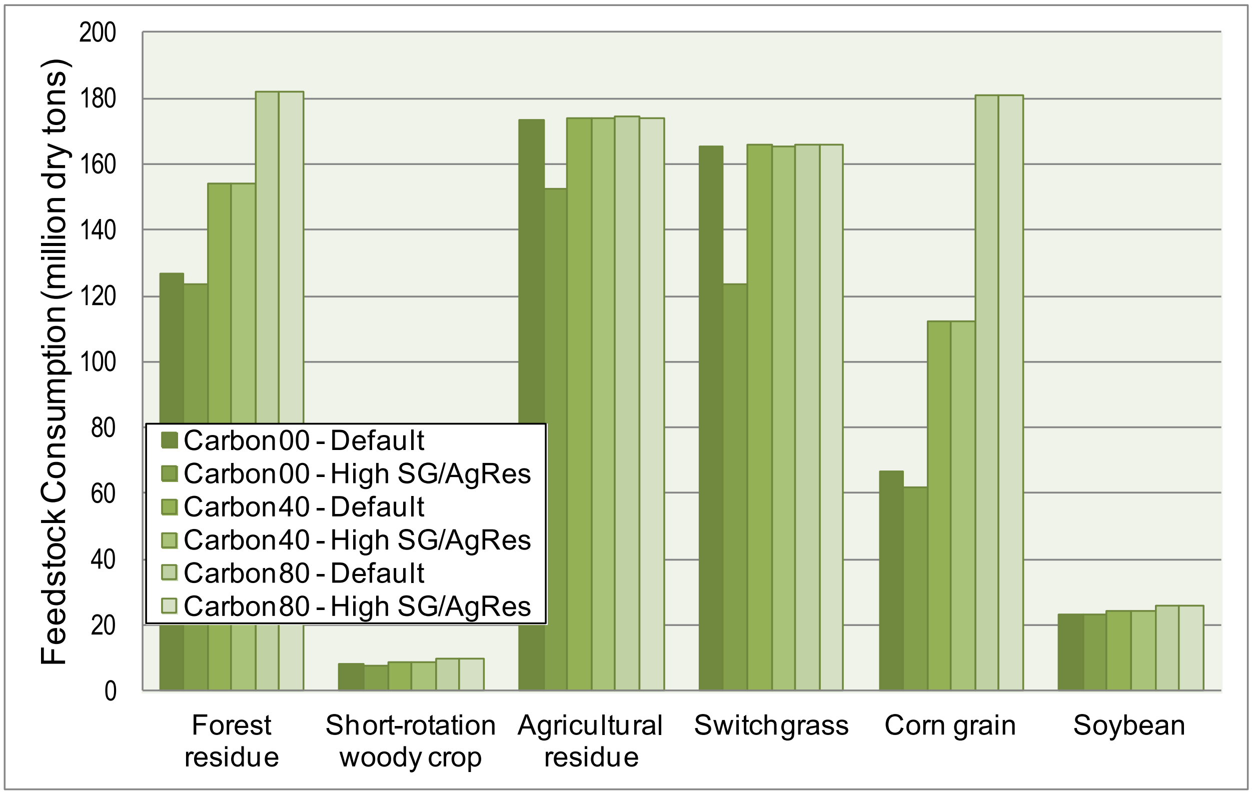


Figure 5.20. Effects of high prices for agricultural residue and switchgrass on biomass utilization in hypothetical mature 2020 markets with varied costs of carbon, by feedstock type

5.4 Different Cost Assumptions for Competing Resources: High Natural Gas Prices; Low Oil Prices

Natural gas and petroleum prices are uncertain as well. Current projections of natural gas prices are lower than most of the projections made over the last decade, due to shale gas technology improvements that increased the available reserves. If environmental or other issues reduce the available reserves or increase the price of extraction, natural gas prices are likely to be higher than projected.

Natural gas prices for the power sector in 2020 were increased by 30% over the default prices to determine if that change would result in additional biopower production. Reduced natural gas prices were not considered because they would likely reduce the biopower penetration further. Since penetration is low already, further reductions are not considered interesting. Due to the simplicity of the BASE model, the effects of increased natural gas prices on conventional fuel prices (due to natural gas used for refining) and biofuel prices (due to natural gas used for fertilizer) could not be included.

As shown in Figure 5.21, in hypothetical mature 2020 markets with no cost of carbon, the natural gas (NG) share in the 2020 power sector goes down from 56% to 52% and is replaced primarily by coal and variable RE. The biopower share only increases from 0.43% to 0.48%, and the total quantity of biomass used for power only increases from 15 million short tons to 17 million short tons annually. Because so little additional biomass is used by the power sector, the effects on the amount of biomass used for fuels is minimal, as shown in Figure 5.22. Figure 5.23 shows the effect on GHG emissions. Emissions in the electricity sector increase by 0.5% over the default case.

NG prices would have to be much higher than 30% over the default projections for the hypothetical mature markets to utilize large quantities of biomass for power.

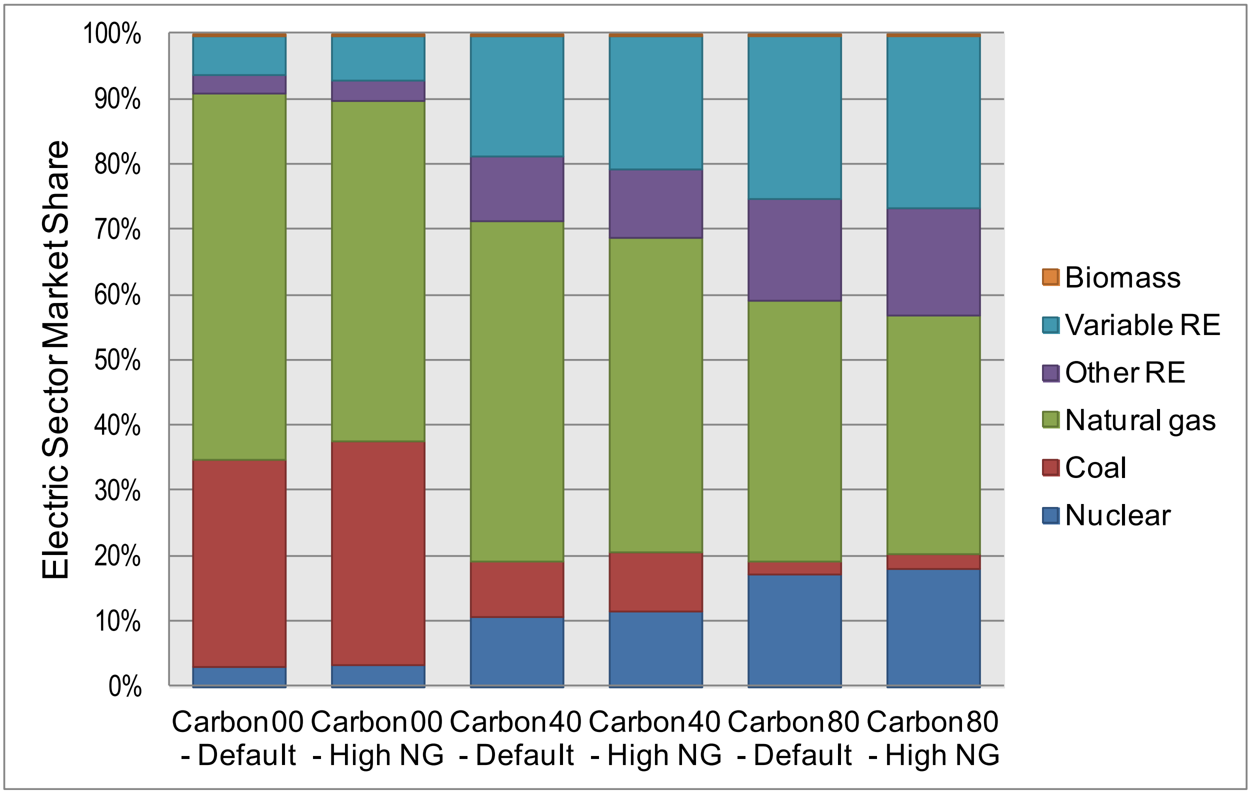


Figure 5.21. Effects of high NG prices on biopower penetration in hypothetical mature 2020 markets with varied costs of carbon

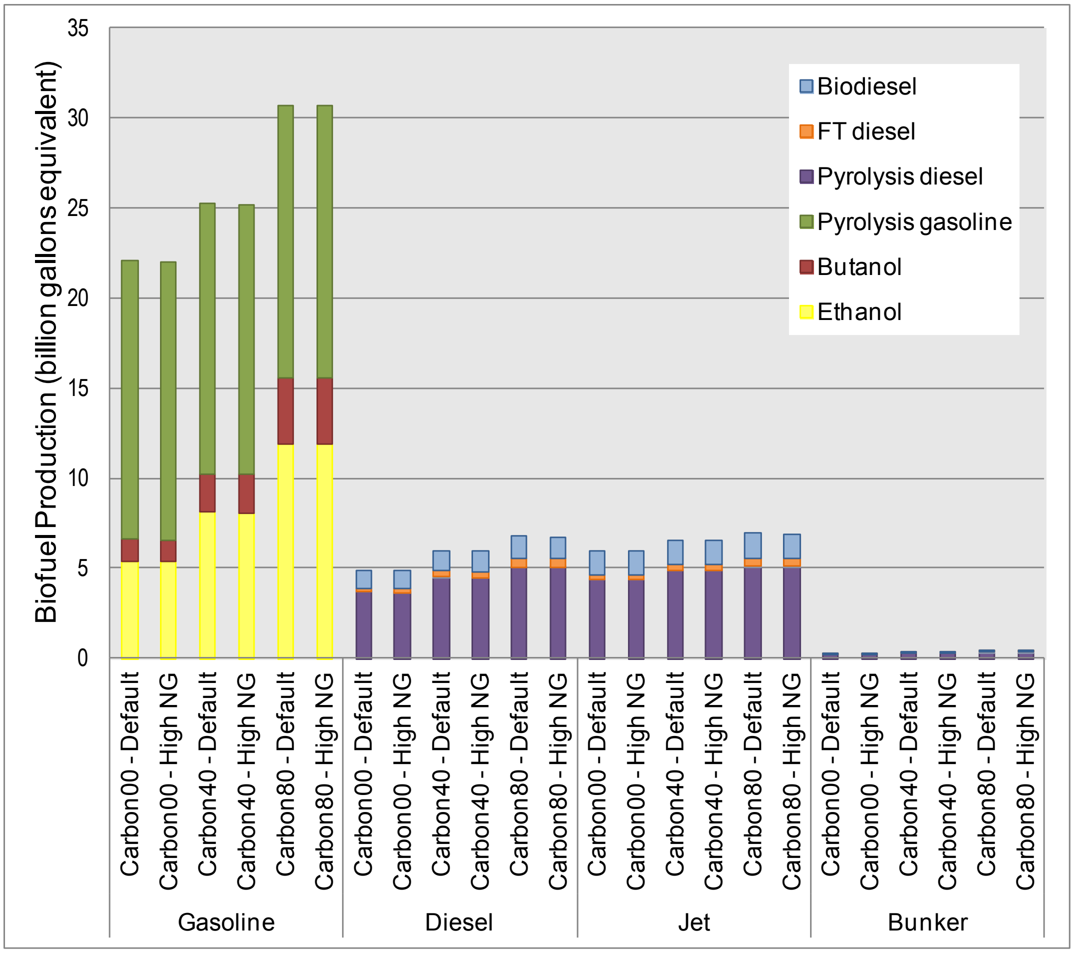


Figure 5.22. Effects of high NG prices on biomass utilization in each hypothetical mature 2020 fuel market with varied costs of carbon by fuel type

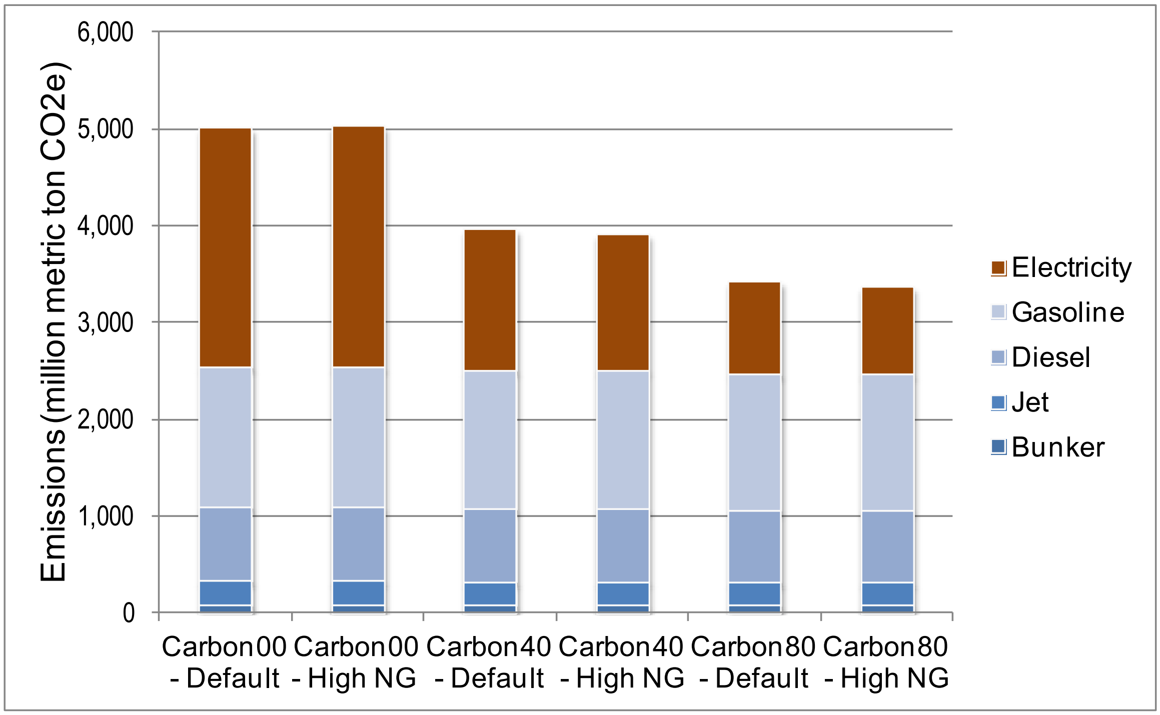


Figure 5.23. Effects of high NG prices on GHG emissions in hypothetical mature 2020 markets with varied costs of carbon

Volatile and potentially lower-than-projected oil prices could affect the market penetration of biofuels because lower oil prices would reduce the penetration of biofuels. Higher oil prices could increase penetration of biofuels if feedstock were available; however, most types of biomass feedstocks are fully utilized in the base case so additional fuel production is not possible. In general, reduced oil prices can affect the size of liquid fuel market (i.e., lower prices result in larger markets). Therefore, researchers used *Annual Energy Outlook* data on reduced pricing and increased market sizes to generate the default cases (see Appendix L).

Figure 5.24 shows the effects of low oil prices on biomass utilization in the hypothetical mature 2020 market. The amount of biomass used for fuels dropped by 96% in the $0/metric ton CO_2e cost of carbon scenario, by 81% in the $40/metric ton CO_2e cost of carbon scenario, and by 56% in the $80/metric ton CO_2e cost of carbon scenario. With less of a demand for biomass for fuel, the amount of biomass used for power increases; as shown in Figure 5.25. The resulting biomass market share is still small, but increases to over 1% at all costs of carbon (shown in Figure 5.26). In Figures 5.27 and 5.28, GHG emissions and petroleum use increased in the low oil price scenarios, although the emissions from the electricity sector are unchanged from the default oil price scenario to the low oil price scenario.

Oil prices have a larger effect on biofuels penetration than almost any other driver, with the possible exception being the effect of R&D on biomass conversion.

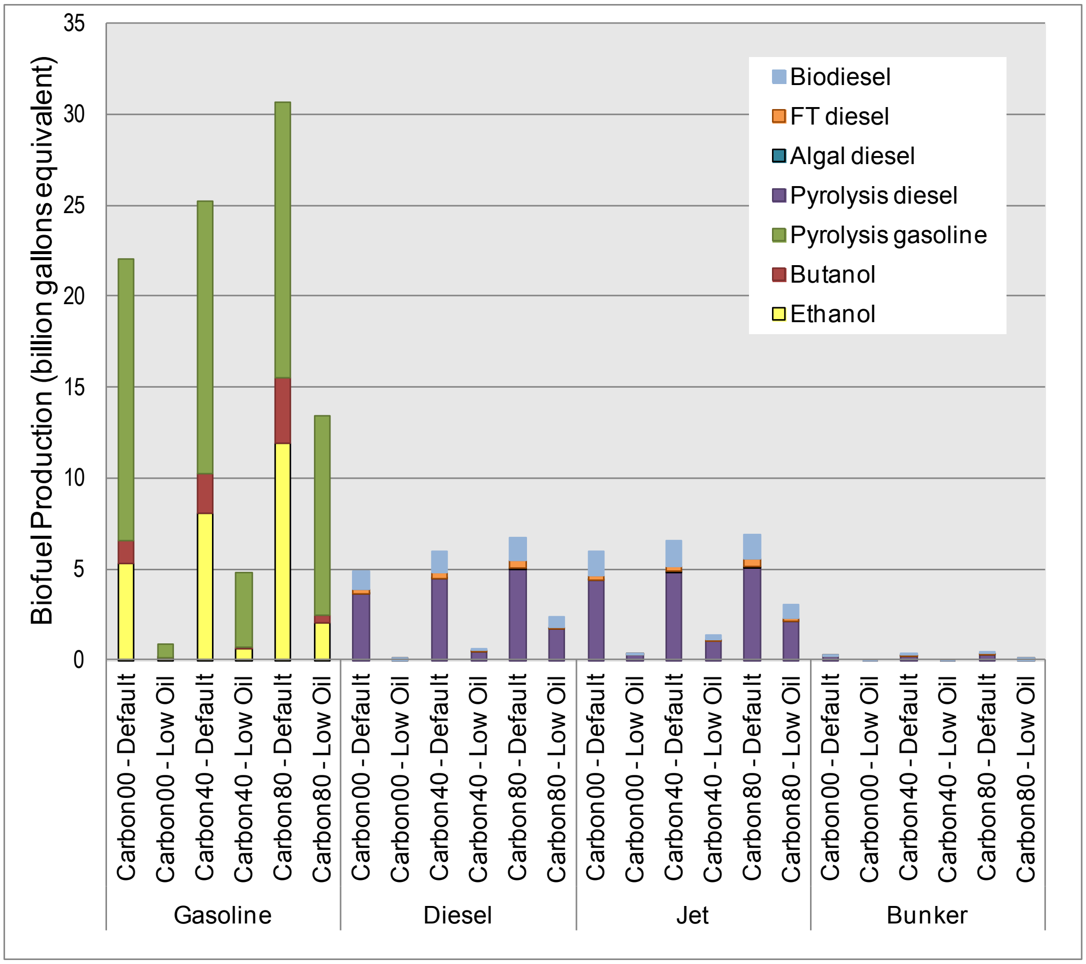


Figure 5.24. Effects of low oil prices on biomass utilization in each hypothetical mature 2020 fuel market with varied costs of carbon by fuel type

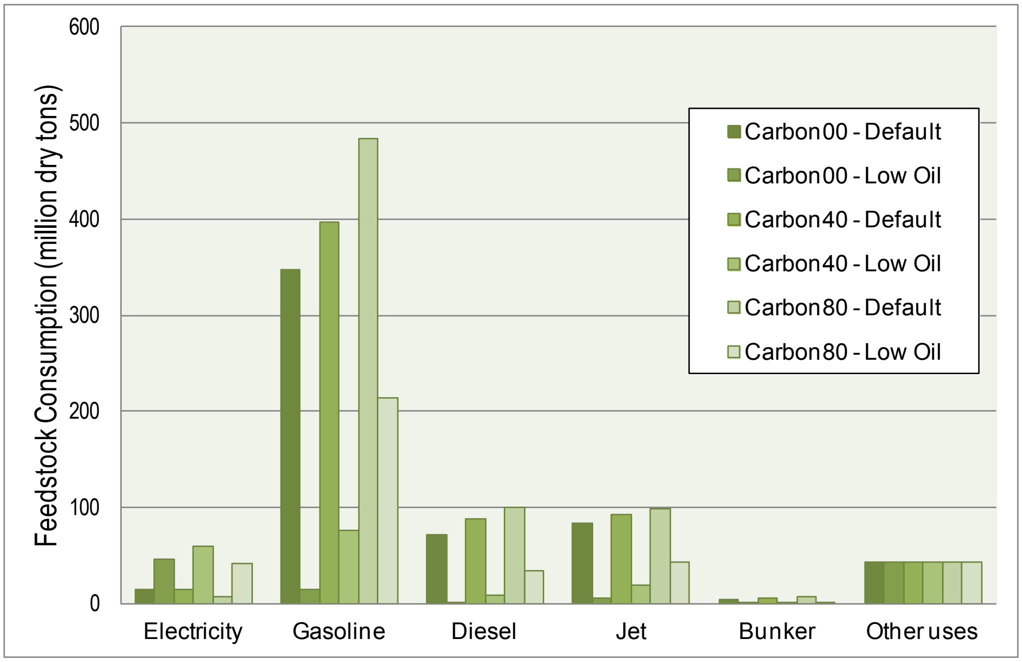


Figure 5.25. Effects of low oil prices on biomass utilization in each hypothetical mature 2020 fuel market

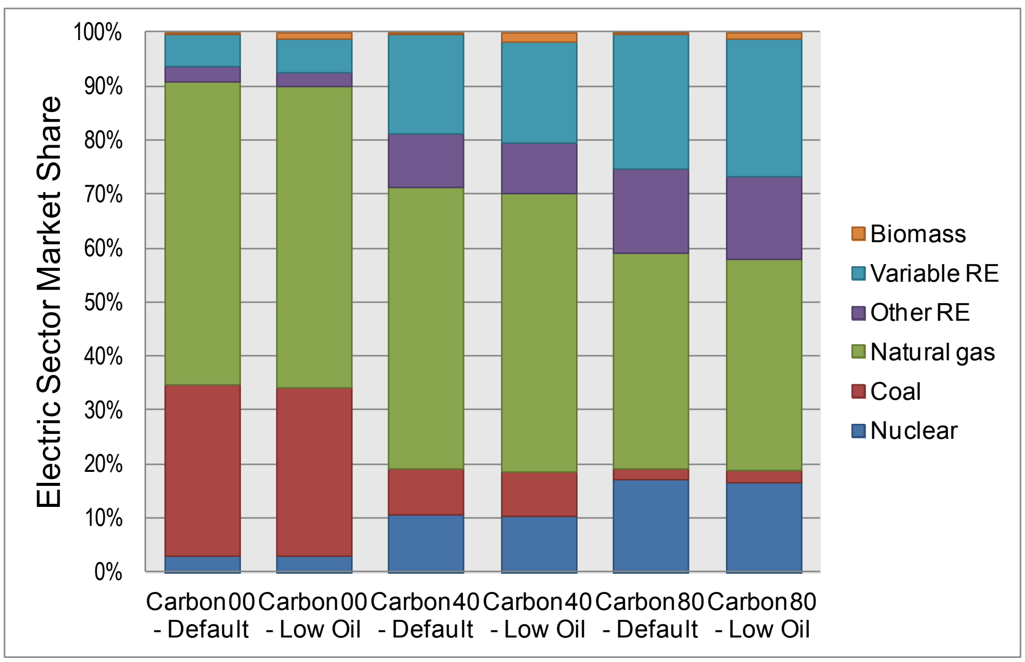


Figure 5.26. Effects of low oil prices on biopower penetration in hypothetical mature 2020 markets with varied costs of carbon

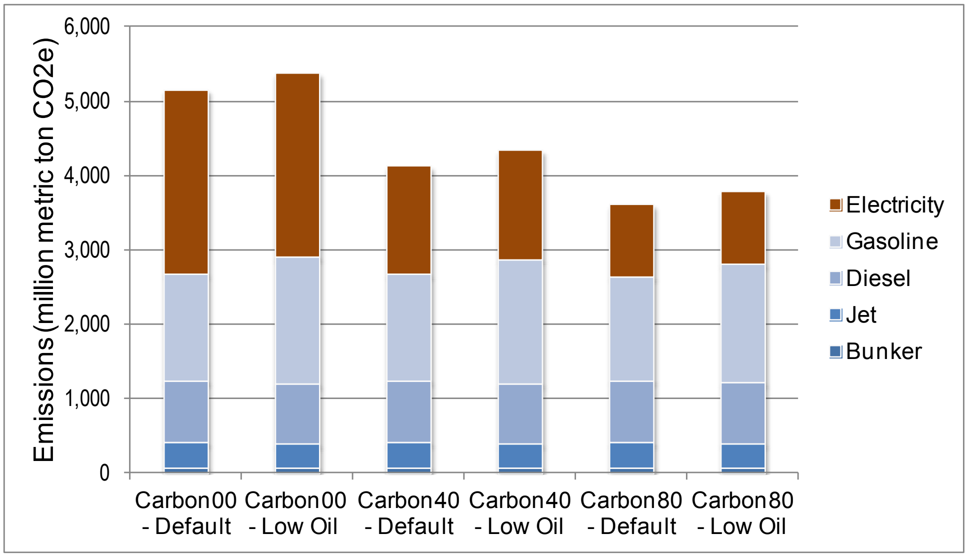


Figure 5.27. Effects of low oil prices on carbon emissions in hypothetical mature 2020 markets with varied costs of carbon

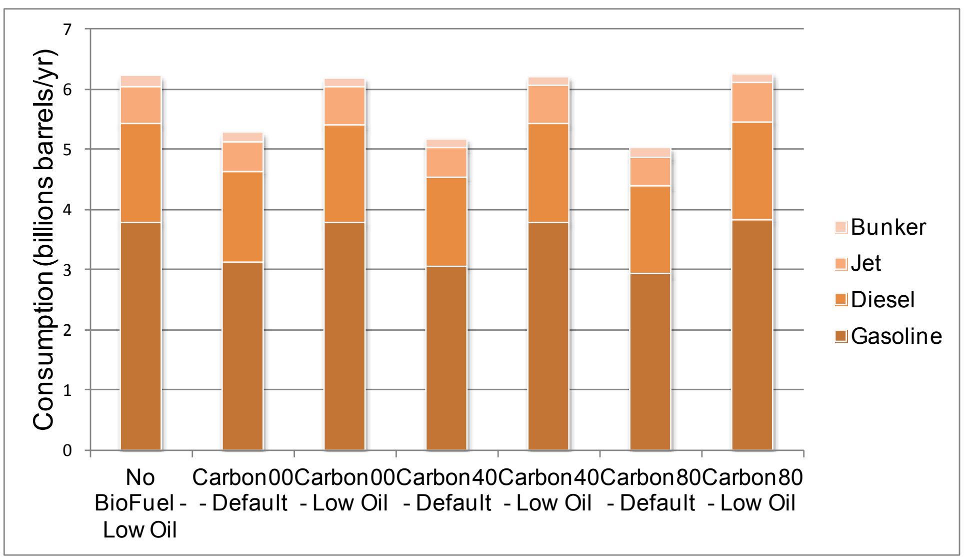


Figure 5.28. Effects of low oil prices on WTW petroleum use in hypothetical mature 2020 markets with varied costs of carbon

6. Proposed Additional Biomass Analysis Work, Sensitivities, and Model Improvements

Many issues that affect biomass and its utilization for energy were not included in this analysis effort due to resource limitations. Further analysis of those issues will affect not only this model and project but other efforts to model the bioenergy system. Some high priority issues that should be considered follow (in no particular order):

- **Import and exports**. Biomass pellets are a growing export market to Europe and Brazilian ethanol is a growing import market. Characterizing supply and demand curves for imports and exports is necessary to improve most biomass market models.
- **Additional utilization of biomass for non-energy products**. Many consider biomass an ideal feedstock for materials and chemicals. For example, Natureworks sells a polylactide polymer that is fermented from sugars today but could be produced from lignocellulosic biomass in the future (Vink et al. 2004). Others are pursuing butanol, ethyl acetate, and other commodity chemicals. The assumptions used in this study for other products from biomass are described in Section 3.4 and may be conservative.
- **Develop elasticities of conventional fuel prices on varying demands**. These values should be developed and added to models such as BASE, so that the potential negative rebound effects on biofuel penetration (i.e., reduced prices of conventional fuels in scenarios where the market volumes of those fuels are lower) can be included. Elasticities are already factored into the power market in BASE, because supply curves for natural gas and coal are included.
- **Develop elasticities for market sizes.** Elasticities for market sizes (e.g., the amount market size grows due to reductions in fuel prices) should be developed and included in models such as BASE. These types of elasticities will help characterize the markets where biofuels penetrate, because they reduce the overall cost of fuel.
- **Transition studies**. Other models have been developed to improve understanding of how biomass markets may evolve. Results of those studies are necessary to identify barriers and issues.
- **Regional Data Sets**. National averages for resources and demands, as used, are unlikely to be realistic across multiple regions. Improving characterization of individual regions (e.g., the Southeast, which has a large biomass resource, but limited other renewable resources) could lead to specific solutions in those regions. Development of a multi-region model with transport across regional boundaries should be considered. However, both collection of the data necessary for such development and model improvements are likely to require a large amount of work. Since the results are unlikely to provide many insights beyond those gained by running region-specific sensitivities, developing a multi-region model is considered a low priority.

Additional sensitivities could be explored with BASE but were not due to space and resource limitations. One example is effects of uncertainty of key variables on the results. Each of the input parameters should be reviewed to identify the uncertainty of the value selected. Different values should then be entered into the BASE model to determine the impact on the calculated market equilibrium. Values that have significant effects on the calculated market equilibrium require additional investigation to determine if an alternate value should be used in the primary data set. Examples of values that need to be revisited include (in no specific order):

- **Costs of biomass-based jet fuel upgrading from diesel fuels**. The primary data set has no cost increase for biomass-based jet fuels over diesel.

- **Conversion costs and efficiencies between feedstock classes**. Each feedstock class has its own energy content and carbohydrate fraction, which result in specific yields. Therefore, the values used for each feedstock class should reflect this. Likewise, processing conditions for each class are likely to vary, which can also affect costs.
- **The level of optimism between biofuels and biopower**. The potential effects of making the assumptions consistent between these values should be investigated. In addition, other sources of conversion costs and efficiencies are available and should be considered. For example, the System Advisor Model provides biopower options, and the parameters it reports could be used for a sensitivity in BASE.
- **CCS costs for biopower**. The primary data set uses costs that are proportional to those used for coal, which are likely to be inaccurate due to the differences in coal and biopower processes and exhaust streams. However, reducing costs by 30% was shown to have little effect on biopower penetration, so improved values may not affect the equilibrium.
- **Cost estimates of biofuel delivery and dispensing costs for drop-in and non-drop-in fuels**. These values were estimated without extensive study so an initial set of results could be generated and the necessity of improving the values could be tested. Improving the cost estimates will require better analysis of delivery and dispensing costs as well as spatial analysis to determine distances traveled. While drop-in fuels can use the petroleum distribution system, biorefineries may not be located in the same places as current petro-refineries.
- **Feedstock supply curves**. In the BT2 study case, these values are cut off at the maximum projected cost. In reality, additional feedstock may be available at higher costs. Studies of the effects of modified supply curves could help identify the potential of additional biofuels. In addition, potential changes to agricultural practices (such as double-cropping) could reduce the supply costs. Finally, post-processing analysis could be used to estimate the effects of additional land use for biomass production on food production.

Other sensitivities could be performed not to understand how to improve the BASE model (as proposed above) but rather to compare results from this model to other models and better understand the potential use for biomass. A list of other sensitivities follows (in no specific order):

- **The parameters used in the GCAM**. These parameters, including efficiencies, costs, and costs of carbon, could be entered in the BASE model to compare results from the two models. The carbon costs used in the BASE analysis were lower than the costs calculated in the GCAM analysis.
- **Market sizes of power, gasoline, diesel, jet fuel, and bunker fuel**. These values, as estimated by TEF fuel infrastructure research, can be used in the BASE model to provide market fractions of each fuel type.
- **The current state of technology for converting biomass to fuels and power**. Entering these values could provide a baseline of where the technology currently stands if it is commercialized. Understanding that state and performing additional sensitivities to determine conversion parameters that lead to high levels of penetration will help identify the necessary targets for conversion R&D.
- **Logit share parameters**. These values could be compared to those used in other studies. Sensitivities of those parameters will help identify the uncertainty of market shares at equilibrium.
- **Other feedstock supply curves**. For example, the aggressive feedstock development case in the BT2 will allow for higher penetration of biomass.

- **Algal diesel costs**. Reduced values should be tested to determine the costs necessary to achieve high levels of market penetration.
- **Renewable production tax credit**. These incentives could change results for the allocation of biomass between power and fuels.
- **Levels of biomass for non-energy products (e.g., plastics)**. Consideration of greater use of biomass for non-energy products could dramatically impact fuel and power market equilibrium.
- **Other policy options, such as a renewable portfolio standard for fuels and/or power**. These values should be studied to understand their effects and costs for hypothetical markets at equilibrium. Many policies are put into place recognizing the near-term costs. Having estimates of long-term equilibrium costs and effects of those policies could improve decisions.
- **Parameters for uniform format biomass.** Feedstock supply is likely to be more expensive in this scenario, but conversion costs could be lower due to economies of scale. As a result, the penetration of biofuels may change.

The model structure can be improved in many ways as well. Enhancements to the model's structure are, for the most part, a lower priority than improving sensitivities and data within the model. Possible model improvements include the following (in order of priority):

- **Limit ratios of pyrolysis gasoline to diesel.** These values should be limited to realistic fuel production ranges to be consistent with design. At this time, the ratios are not fixed within the BASE model and each product is optimized to best meet market demands. Most current process designs for pyrolysis-based fuels have limited ability to distinguish between the gasoline and diesel markets.
- **Add Monte Carlo analysis capability to the BASE model**. A relatively easy process, a Monte Carlo analysis can assist in understanding how the logit function's values perform, and possibly improve the selection of those values by increasing the logit value and varying input parameters. In addition, Monte Carlo analysis allows for estimation of ranges of results, instead of single parameters without confidence intervals.
- **Use POLYSIS inputs in BASE instead of results**. Biomass supply data for this project is derived from the BT2's POLYSIS results study. Instead of results, original POLYSIS inputs could be used to populate the BASE model. However, it is important to understand that using inputs could lead to supply curves that are not truncated.
- **Add CCS to fuel production processes**. In this analysis, CCS was considered for power production, but not for fuels. For some of the fuel options (e.g., ethanol), a resulting carbon dioxide stream could be sequestered at a lower cost than for many of the power options. Therefore, CCS should be added to fuel production processes to better understand if CCS and a cost of carbon still drive the biomass resource to power production.
- **Compete CCS and non-CCS options**. In this analysis, CCS is either not allowed (in the default case), or included only as an option for biopower. No studies of the economic competitiveness of CCS versus non-CCS options were considered. Results may differ if CCS and non-CCS options compete, but this would require a substantial modification to the BASE model.
- **Consider additional fuel options**. Methanol, di-methyl ether, hydrogenated biodiesel, and gasoline produced from biomass via the methanol-to-gasoline process could be examined as possible fuel options. Hydrogen for fuel cell electric vehicles should also be considered. Many other viable biofuel options are being explored by the industry and should be added to the BASE model.

7. Conclusions

Biomass is a limited resource with many competing uses. Its allocation for fuel, power, and products depends upon characteristics of each of these markets, their interactions, and policies affecting these markets. Federal policy and activities have supported both biofuels and biopower with the sometimes contradictory goals of reducing petroleum use and reducing emissions of GHGs. Allocation of resource between biopower and biofuels, as well as across different fuels markets, is of keen interest in understanding how this energy resource might contribute to the national goals of reduced petroleum use and GHG emissions.

Most models only consider biomass in either the power or fuels market. If one looks at the results of such models, the biomass availability and utilization could easily be double-counted because competition from the other sector is not considered. Double-counting could lead to unwarranted conclusions and decisions; thus studies that include multiple sectors are needed.

Conclusions Contingent upon Model Structure, Assumptions, and Limitations

This study was performed and the BASE model developed to improve understanding of how biomass might be most economically allocated across sectors in hypothetical mature markets. The BASE model is a market equilibrium model so it is does not consider market evolution issues. It is also currently a national model and thus is not capable of differentiating either potential within or issues specific to regions. Input data for the BASE model were collected from publicly available sources and includes projections of biomass supply cost curves, biomass harvesting and transport costs, biomass conversion costs, electricity costs from other sources, fuel transport and dispensing costs, and well-to-wheel greenhouse gas emissions and petroleum use. Levelized costs for each fuel and electricity are calculated based on the inputs and include a cost of carbon for some scenarios.

The 2050 levelized cost projections of cellulosic biofuels indicate that they are cost-competitive with gasoline at feedstock costs of up to $160/dry ton. On the other hand, 2050 levelized cost projections of biopower indicate that it is not cost competitive with feedstock costs of over $40/dry ton.

Biofuels Can Attain Considerable Market Share

Under mature market conditions with default biomass feedstock, transport, and conversion assumptions and business-as-usual projections for market sizes and conventional fuel prices, biomass is capable of gaining transportation sector market share (particularly in the diesel and jet fuel markets). At no cost of carbon in a hypothetical 2020 market, biofuels can exceed 25% of the jet fuel market, 15% of the gasoline market, and 8% of the diesel market. In a scenario where the cost of carbon is high ($80/metric ton CO_2e), biofuels penetration is higher because biofuels are less carbon intensive than conventional fuels. Biofuel penetration is about 30% of the jet fuel market, 20% of the gasoline market, and 10% of the diesel market in a hypothetical, mature 2020 market.

Biofuel Penetration Constrained by Biomass Resource Size

Biomass could attain an even larger market share in the hypothetical markets if it was not resource limited. In the default scenario, the feedstock supply curves were completely depleted for some lignocellulosic feedstocks (i.e., SRWC, agricultural residues, and switchgrass) even in the zero cost of carbon scenario. Complete depletion of feedstocks indicates that wider deployment of biofuels is warranted by the market and suggests that both feedstock and conversion cost projections are optimistic. Consequently, there are other non-economic constraints or non-equilibrium factors that are slowing deployment.

Biopower Requires Both CCS and High Cost of Carbon to Compete

Biopower does not achieve much market share (<1%) even with a price of carbon of \$80/metric ton CO_2e, unless CCS is available. The primary reason biopower does not penetrate is that it is more expensive than other low-carbon electricity options, which compete successfully with conventional generation, especially in scenarios with higher costs of carbon. Optimistic assumptions of biopower capital costs and efficiency do not considerably increase its market share. Decreasing capital cost by 30% only increases biopower market share in a hypothetical mature 2020 market from 0.2%-0.5% to 0.4%-0.9%. Likewise, decreasing the heat rate by 30% or increasing the cost of natural gas by 30% only has a minor effect on biopower market share. On the other hand, availability of CCS increases biopower penetration from essentially nothing to 2% of the power market with a \$40/metric ton cost of carbon and 13% of the market with an \$80/metric ton cost of carbon in a hypothetical mature 2050 market.

Pyrolysis-Based Fuels are Projected to be More Competitive

Among the different types of biofuels considered in this study, pyrolysis fuels (gasoline and diesel) are more competitive with conventional fuels than other biofuels and have the greatest potential for market penetration. In a scenario where the R&D on pyrolysis-based fuels failed and the fuels were not available in 2050, biofuel penetration dropped dramatically in the diesel and jet markets—by 90% in the diesel market and by 65% in the jet fuel market. The share of biofuels in the gasoline market increased slightly, and most of the biomass was still utilized to make fuels that compete in the gasoline market (e.g., ethanol and butanol).

High Costs of Carbon Drive Up Demand for Biomass for Fuels

While costs of carbon have a greater decarbonizing effect on the electricity sector compared to the fuel sector, markets with a carbon cost drive up demand for biomass in the transportation sector. Therefore, the presence of carbon costs drives up the cost of biomass and makes biopower less competitive with other power-generation options. The result is different if CCS is available for the electric sector and an \$80/metric ton CO_2e cost of carbon is considered. Under those conditions, biopower with CCS yields negative emissions (net sequestration of GHG), making biopower competitive. A hypothetically mature 2050 market with CCS available and an \$80/metric ton CO_2e cost of carbon results in a 50% reduction in biomass utilization for fuel.

Biofuel Availability Reduces Petroleum Use

A hypothetical 2020 market with biofuels has a well-to-wheels petroleum use that is 88% of one without biofuels when there is no cost of carbon. Petroleum use is further reduced to 84% of a non-biofuel market when a cost of carbon of \$80/metric ton CO_2e is considered. Increased costs of carbon only have minor effects on reductions in petroleum use, because most of the biomass supply is utilized for fuel at no cost of carbon, making only small increases possible.

Sensitivity to Supply Prices

Corn ethanol, corn butanol, and biodiesel from soybean deployment are highly sensitive to the prices of those commodities. Increasing corn and soybean prices by 30% decreases of corn and soy utilization for fuels. Corn utilization drops from 66 million short tons to 21 million short tons and soy drops from 23 million short tons to 9 million short tons in a hypothetical mature 2020 market with no cost of carbon. Lignocellulosic biomass utilization does not increase at high corn and soybean prices; instead the market need is met primarily with conventional fuels.

Effects of Pricing from Other Sectors

If petroleum product prices are low, biomass penetration in hypothetical mature markets drops considerably. For example, in the hypothetical mature 2020 market using the *Annual Energy Outlook* low oil price case projections for conventional fuels, the amount of biomass utilized for fuels drops by 95% in the \$0/metric ton CO_2e cost of carbon scenario, by 82% in the \$40/metric ton CO_2e cost of carbon scenario, and by 57% in the \$80/metric ton CO_2e cost of carbon scenario. The use of petroleum and GHG emissions are both projected to increase when using low oil price projections.

Increased natural gas prices had a minor effect on utilization of biomass for power; however, the increase in biopower penetration was minimal because the electricity market shifted slightly from natural gas to coal and other renewables. Because the change of biomass use for the power sector was small, there was no effect on the fuels sector.

Algal diesel with its default parameters has a small penetration of the market in 2050. Its market share increases with a cost of carbon but is still below 14% of the diesel market and 17% of the jet fuel market (at \$80/metric ton CO_2e).

Bottom Line

We found that biofuels are likely to be able to compete successfully with petroleum-based fuels and use a large share of the potential resource if R&D is successful and petroleum product prices are as high as the EIA projects. Policies and market evolution may affect how biofuel and biopower markets develop and their ultimate equilibrium state; however, biofuels have a large potential and can reduce petroleum use within the United States.

Appendix A: Summary of Other Analyses

1. Cowie, A.L.; Gardner, W.D. (2007). "Competition for the Biomass Resource: Greenhouse Impacts and Implications for Renewable Energy Incentive Schemes." *Biomass and BioEnergy*, 31, 601 (Cowie and David Gardner 2007).

   This study compares greenhouse gas (GHG) mitigation impacts in Australia for using sawmill residues for (a) particle board manufacturing, (b) generation of electricity, or (c) no use—power produced via coal and particle board produced using fresh plantation biomass. All cases are analyzed assuming 400 hectares of mature radiate pine plantation (100 kilotons dry matter per year of mill residue). GHG reduction emissions are determined for the bioenergy projects relative to the reference fossil-fuel case. If the residues are used for bioenergy, the net emissions reduction is 167 kt carbon dioxide equivalent (CO_2e), whereas if the residues are used for particle board manufacturing, the net emissions reduction is 201 CO_2e.

2. Ignaciuk , A.; Vohringer, F.; Ruijs, A.; van Ireland, E.C. (2006). "Competition Between Biomass and Food Production in the Presence of Energy Policies: A Partial Equilibrium Analysis." *Energy Policy*, 34, 1127 (Ignaciuk et al. 2006).

   This study uses a partial equilibrium model to investigate the effect of taxing conventional electricity production in combination with subsidizing biomass or bioelectricity production on the production of biomass and agricultural commodities and on the share of biopower in total electricity generation in Poland. The model includes land, capital/labor, and oil/coal/gas factors, and agriculture, biomass, bioelectricity, and conventional electricity sectors. The model allows for limited international trade. The main aim of the work is to investigate the effect of energy policies on GHG emissions, land use, and production, and the prices of biomass and agricultural commodities. The study concentrates on two energy policies: (1) tax on conventional electricity consumption, and (2) carbon tax on fossil fuel. "Results show that combining a conventional electricity tax of 10% with a 25% subsidy on bioelectricity production increases the share of bioelectricity to 7.5%. Under this policy regime, biomass as well as agricultural production increase. A carbon tax that gives equal net tax yields, has better environmental results, however, at higher welfare costs and resulting in 1% to 4% reduction of agricultural production."

3. Sun J.C.; Li, P.X.; Hou, L.N. (2011). "Game Equilibrium of Agricultural Biomass Material Competition –Its Assumptions, Conditions and Probability." *Energy Procedia*, 5, 1163 (Sun, Li, and Hou 2011).

   The purpose of this study was to investigate the mechanism of agricultural biomass material competition between the power generation and straw pulp industries in China. A two-stage game model (based on biomass distribution and structure of collection costs) was used to analyze the parameters of equilibrium (i.e., unit transportation cost, and profit space). "The results show that raw material competition will hardly bring about the sustainable development of the two industries based on agricultural residues in the assumed circular collection area."

4. Berndes, G.; Hoogwijk, M.; van den Broek, R. (2003). "The Contribution of Biomass in the Future Global Energy Supply: A Review of 17 Studies." *Biomass and Bioenergy*, 25, 1 (Berndes, Hoogwijk, and van den Broek 2003).

   This report is a review article that is based on 17 earlier studies on biomass in the future global energy supply. The studies in the review reached very different conclusions about the possible contribution of biomass in the future global energy supply, ranging from <100 Exajoule (EJ)/year (yr) to >400 EJ/yr predicted for 2050. The major reasons for differences are associated with different assumptions for land availability and yield levels in energy crop production.

5. Grahn, M.; Azar, C.; Lindgren, K.; Berndes, G.; Gielen, D. (2007). "Biomass for Heat or as Transportation Fuel? A Comparison between Two Model-Based Studies." *Biomass and Bioenergy*, 31, 747 (Grahn et al. 2007).

   This study compared the results obtained with the Biomass Environmental Assessment Program (BEAP) model by (Gielen et al. 2003; Gielen et al. 2002) to those obtained using the Global Energy Transition (GET 1.0) model (Azar, Lindgren, and Andersson 2003). Both models are energy economy models of the global energy system.

   "The BEAP model is a mixed integer programming model, and simulates an ideal market based on an algorithm that maximizes the sum of the consumers' and producers' surplus. The GET model is a linear programming model that is set up to meet exogenously given energy demand levels at the lowest energy system cost. Both models exhibit so-called 'perfect foresight,' which means that all features of the model (future costs of technologies, future emission constraints, availability of fuels, etc.) about the future are known at all times."

   The BEAP model includes gasoline/diesel (including from biomass via Hydrothermal Upgrading oil), methanol, ethanol, FT diesel, and hydrogen (fossil-fuels based) transportation fuels, whereas the GET model includes gasoline/diesel, methanol, hydrogen, and natural gas transportation fuels. Both models consider transportation fuel competition with power and heat, oil, coal, natural gas, nuclear, biomass, solar, hydro, and wind energy sources.

   The CO_2 emission trajectories predicted by each model and the "WRE" trajectory (average of the 350 and 450 ppm trajectories) are displayed in Figure A.1. Figure A.2 shows the time evolution of biomass usage and the break out of transportation fuels predicted by the two models.

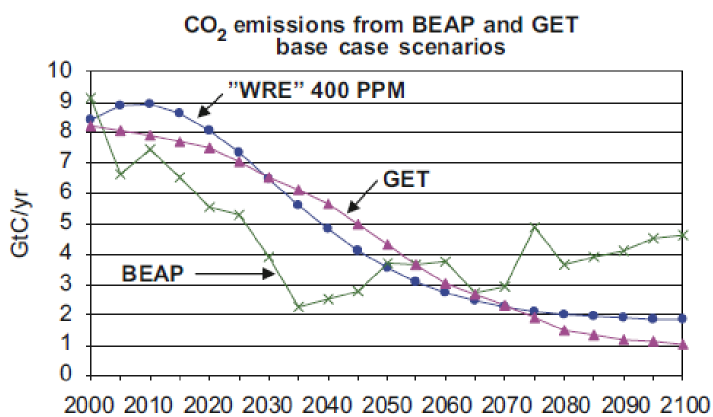


Figure A.1. CO_2 emissions from BEAP and GET base case scenarios

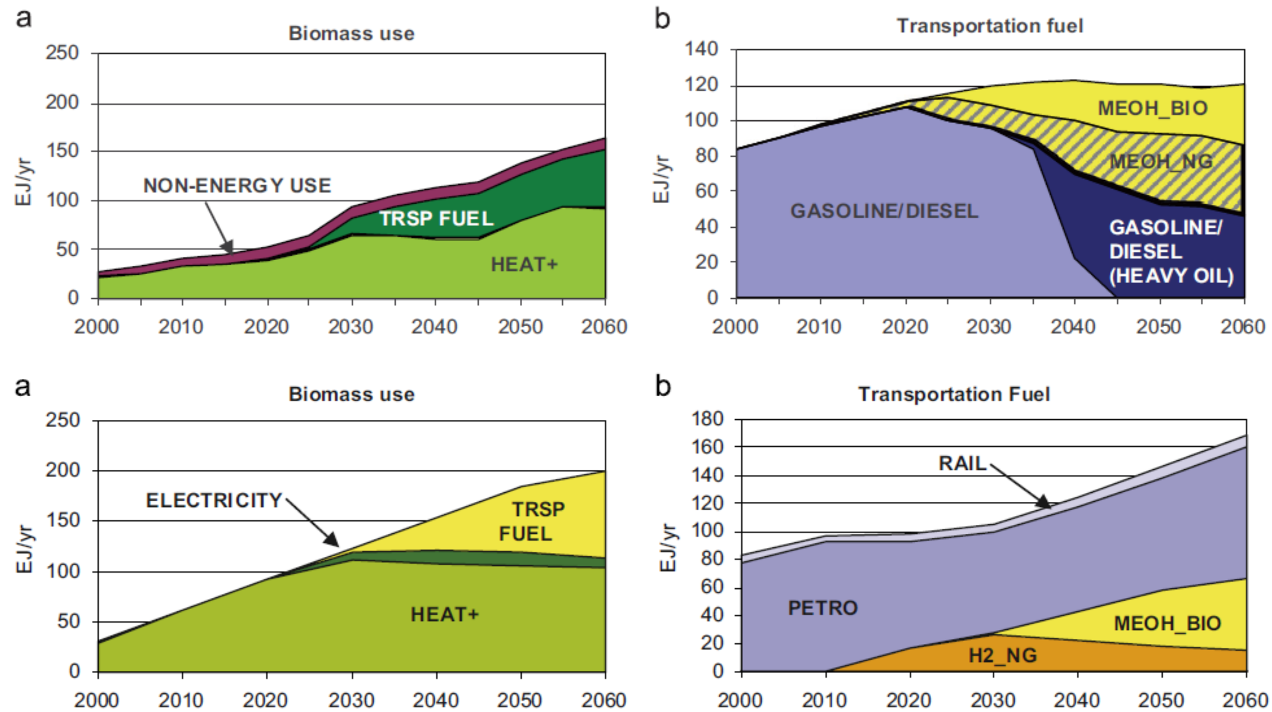


Figure A.2. Time evolution of biomass usage and break out of transportation fuels predicted by the two models

6. Khanna, M.; Chen, X.; Huang, H.; Onal, H. (2010). "Supply of Cellulosic Biofuel Feedstocks and Regional Production Patterns." Agricultural & Applied Economics Association's 2010 AAEA, CAES & WAEA Joint Annual Meeting, Denver, CO, July 25-27, 2010 (Khanna et al. 2010).

   This study uses a dynamic, multi-market, nonlinear model Biofuel and Environmental Policy Analysis Model to examine the economically viable supply of agricultural biomass at various biomass prices, and the mix of feedstocks that will be produced at these prices. The model also examines the regional pattern of production of various cellulosic feedstocks and the spatial mix of the feedstock production. The study concludes that 617-923 million metric tons per year (million T/yr) of biomass can be produced at a price of $140/MT in 2030. The results depend on residue collection technology, cost of producing bioenergy crops and their yields, and land availability. At this feedstock price, the model predicts that it would lead to the use of ~18 million ha of idle cropland/cropland pasture for perennial grasses. Additionally, the study considers the following scenarios: (1) low cost of production, (2) 50% higher switchgrass yield, (3) high rates of residue collection, (4) exclusion of conservation reserve program land, (5) high cost of production, and (6) high cost of Miscanthus and low cost of other feedstocks.

7. Kalt, G. (May 2011). "An Assessment of the Implications, Costs and Benefits of Bioenergy Use Based on Techno-economic Approaches." Dissertation, Institut fur Energiesysteme Elektrische Antriebe (E370) (Kalt 2011).

   Part III of the thesis uses the simulation model SimBioSys to investigate how future developments (up until 2030) of the bioenergy sector might occur for Austria, based on techno-economic approaches. The model is based on profitability analysis of different biomass utilization pathways, including influencing parameters such as subsidies, fossil-fuel prices, and biomass supply curves. The following scenarios were investigated and reported on:

- No policy scenarios: no subsidies or tax incentives for bioenergy
- Current policy scenarios: current subsidies and tax incentives
- Specific support scenarios: increasing levels of financial incentives for certain utilization paths.

The model includes bioenergy technologies for heat, electricity, and transportation fuels (i.e., cellulose bioethanol, gasification/FT synthesis, cane ethanol, starch ethanol, centralized biodiesel, and decentralized biodiesel).

"The main characteristics and features of the model are:

- It is a myopic bottom-up simulation model for the bioenergy sector.
- Based on continuous supply curves for biomass resources, the deployment of bioenergy plants is simulated by determining the biomass demand where the energy production costs of bioenergy technologies and the respective reference technologies are in equilibrium.
- The model allows for the simulation of four different support schemes for bioenergy: investment subsidies, quotas, premia, and feed-in tariffs.
- The simulation results are evaluated by numerous criteria, providing insight into the costs and benefits of bioenergy in the resulting scenario.
- The model is implemented in the numerical computing environment MATLAB."

8. Morrow, W.R.; Balash, P. (2008). "Comparing Alternative Uses of Scarce Biomass Energy Resources through Estimations of Future Biomass Use for Liquid Fuels and Electricity." DOE/NETL-2008/1302, November 1, 2008 (Morrow and Balash 2008).

   The model in this study considers two technology pathways for biomass energy: cellulosic ethanol production and biopower (co-firing), and calculated CO_2 emission reduction. Linear programs forecast demands for biomass resources in the transportation and electricity sectors through 2020. The model investigates different market conditions and policy choices in which biomass will be demanded by each sector. The study concludes that biomass allocation depends on future oil prices, future progress in cellulosic ethanol production technology, and society's desire to mitigate CO_2 emissions from existing coal-fired power plants.

9. Davis, R.; Tan, E.; Kinchin, C.; Kelly, C. (2011). "*Comparison of Biomass Pathways for Vehicle Use.*" NREL Milestone Report, June 30, 2011 (Davis and Tan 2011).

   This analysis considers the following biomass usage pathways: traditional boilers (biopower), integrated gasification and combined cycle (IGCC) biopower, ethanol via biochemical and thermochemical-gasification pathways, diesel via gasification/FT synthesis, and gasoline via gasification, methanol synthesis, and methane-to-gasoline (MTG). The analysis also considers wood (farmed trees), corn stover, and switchgrass feedstocks. A comparison of feedstocks and conversion technologies is included in terms of miles driven/dry short ton in plug-in electrical vehicles powered by biomass-derived electricity and internal combustion vehicles powered by biofuels. The study estimates technology improvements using process targets with operation in 2015 as well as reports WTW GHG emissions, water use, energy return on investment, and estimated cost to consumer (cents/mile). The ranking of the conversion technologies for the miles/dry short ton of biomass metric are: IGCC power > boiler power > MTG gasoline, thermochemical conversion ethanol, FT diesel. The ranking of technologies for the total WTW GHG emissions per mile driven metric are: IGCC power < boiler power << FT diesel < biochemical conversion ethanol < thermochemical conversion ethanol. For this metric, generally wood << switchgrass < corn stover.

10. Ohlrogge, J.; Allen, D.; Berguson, B.; DellaPenna, D.; Shachar-Hill, Y.; Stymne, S. (2009). “Driving on Biomass.” *Science*, 324, 1019 (Ohlrogge et al. 2009).

    This study focuses on the chemical energy efficiency of using biomass for power compared to biomass for ethanol. In the ethanol case, an internal combustion engine is assumed, whereas in the power case, an electric car is assumed. The authors conclude that, for transportation, biomass-to-ethanol is 10% efficient, whereas biomass-to-power is 20%-23% efficient (energy used to move the vehicle divided by energy available in the biomass).

11. Wahlund, B.; Yan, J.; Westermark, M. (2004). “Increasing Biomass Utilisation in Energy Systems: A Comparative Study of CO_2 Reduction and Cost for Different Bioenergy Processing Options.” *Biomass and Bioenergy*, 26, 531 (Wahlund, Yan, and Westermark 2004).

    This study focuses on investigating CO_2-reduction technologies for application in Sweden, quantifying the CO_2-reduction rate and calculating the specific cost of reduction. The study includes the following biomass uses/pathways: drying/pelletization (for heat), combined heat and power, methanol and DME for transportation fuel, ethanol via dilute acid hydrolysis for transportation fuel, and ethanol via enzymatic hydrolysis for transportation fuel. The study concludes that: (1) the largest and most long-term sustainable CO_2 reduction would be achieved by converting the woody biomass into pellets for coal substitution, and (2) conversion to transportation fuels provides only half of the CO_2 reduction at a higher cost.

12. Campbell, J.E.; Lobell, D.B.; Field, C.B. (2009). “Greater Transportation Energy and GHG Offsets from Bioelectricity than Ethanol.” *Science*, 324, 1055 (Campbell, Lobell, and Field 2009).

    This study considers the use of biomass for: (1) conversion into ethanol for use in an internal combustion engine, and (2) conversion to power for use in an electric vehicle. The study concludes that bioelectricity outperforms ethanol across a range of feedstocks, conversion technologies, and vehicle classes. In addition, bioelectricity produces an average of 81% more transportation kilometers and 108% more emission offsets per unit area of cropland than cellulosic ethanol.

13. Institute for Energy and Environmental Research and Verband der Chemischen Industrie. (October 2007). “Biomass as a Resource for the Chemical Industry”, Frankfurt Germany (Institute for Energy and Environmental Research (IFEU) 2007).

    This study focuses on: (1) investigating the effect of using biomass in the chemical industry on GHG reduction, (2) comparing biomass use for energy generation, generation of transportation fuels, and use as raw material in the chemical industry, and (3) identifying advisable biomass use strategies for the chemical industry. The study concludes that the direct combustion of dry biomass to generate power shows the biggest potential GHG savings, and biopower is commercially ready, whereas biomass use in the fuel sector or chemical industry with high potential GHG savings is still in the development stage.

14. Black & Veatch. (2008). “Renewable Energy Options” report. April 16, 2008 (Black & Veatch 2008).

    This study compares the LCOE for biopower (dedicated and co-fired) to the LCOE for electricity generated via land fill gas, solar thermal, solar photovoltaic, hydroelectric, wind, geothermal, marine current, and wave technologies.

15. Walker, T.; Cardellichio, P.; Colnes, A.; Gunn, J.; Kittler, B.; Perschel, B.; Recchia, C.; Saah, D. (June 2010). “Chapter 2: Biomass Sustainability and Carbon Policy Study.” Manomet Center for Conservation Sciences, NCI-2010-03 (Walker et al. 2010).

This study looks at power generation with a variety of different technology options, including biopower and co-firing options. The study reports CO_2 emissions inputs and outputs and maximum affordable cost of biomass for biomass options for present-day power production in Massachusetts. The study includes some analyses for biochemical ethanol production, pyrolysis, and other emerging technologies in transportation fuel; however, there is insufficient information provided to discern any reliable conclusions.

16. Alfonso, D.; Perpina, C.; Perez-Navarro, A.; Penalvo, E.; Vargas, C.; Cardenas, R. (2009). "Methodology for Optimization of Distributed Biomass Resources Evaluation, Management, and Final Energy Use." *Biomass and Bioenergy*, 33, 1070 (Alfonso et al. 2009).

    This study considers different technology options for biopower and quantifies the efficiencies. The study also investigates biomass logistics in some detail.

17. Kalt, G.; Kranzl, L.; Haas, R. (2010). "Long-term Strategies for an Efficient Use of Domestic Biomass Resources in Austria." *Biomass and Bioenergy*, 34, 449 (Kalt, Kranzl, and Haas 2010).

    This study looks at the long-term possibility of converting biomass to heat, power, and transport fuel in Australia under different scenarios. GHG mitigation estimates and the costs associated with GHG reduction are also provided. The study used the simulation model Green-XBA to simulate future developments of the Australian bioenergy sector up until 2050. The model uses dynamic supply curves; technology data for different biomass heating systems, biomass combined heat and power, and heating/biofuels production plants; cost data of reference systems (fossil-fuelled); and the Australian energy demand structure/development. "Based on the input data, the model simulates future investments in bioenergy systems." Biodiesel, bioethanol (biochemical and thermochemical), and gasification-FTS transportation-fuel conversion technologies are represented in the "biofuels" portion of the model, including factors for technological learning over time. A transport scenario, balanced scenario, heat-and-power scenario, and no-policy scenario are included. The study concludes that, from a GHG reduction and economic efficiency standpoint, bioenergy policies should focus on the promotion of biomass to heat, and to some extent biomass combined heat and power. Additionally, the study concludes that focusing on liquid transportation fuels has adverse effects on the bioenergy sector development due to increased competition for limited biomass resources.

18. Campbell, J.E.; Block, E. (2010). "Land-Use and alternative Bioenergy Pathways for Waste Biomass." *Environ. Sci. Technol.*, 44, 8665 (Campbell and Block 2010).

    This study considers the effects of converting sugar cane production lignocellulose waste into ethanol. Cellulosic ethanol production for export from developing countries to developed nations is compared to local heat and power production. For the same amount of waste biomass, the authors concluded that biopower offsetting natural gas achieves 58% greater GHG reduction than cellulosic ethanol offsetting gasoline. Similar offsets are anticipated if cellulosic ethanol is used to offset additional sugar cane ethanol production.

19. Trink, T; Schmid, C.; Schinko, T.; Steininger, K.W.; Loibnegger, T.; Kettner, C.; Pack, A.; Toglhofer, C. (2010). "Regional Economic Impacts of Biomass Based Energy Service Use: A Comparison Across Crops and Technologies for East Styria, Austria." *Energy Policy*, 38, 5912 (Trink et al. 2010).

    This study uses a "…two-plus-ten-region energy-focused computable general equilibrium model that acknowledges land competition in analyzing the sub-state local-regional (East Styria and rest of Styria) economic implications of such a strategy, embedded within a global context." The model is based on a full cost analysis of selected biomass conversion technologies (biodiesel) for a range of agricultural and forestry crops, as well as for insulation. The study focuses on short-term and long-term impacts on welfare, regional gross domestic product (GDP), and employment by technology and region as well as examines a couple of different compulsory blending levels of biodiesel in the diesel pool.

20. Brookhaven National Laboratory (BNL). (Multiple personal communications 2004-2010). MARKAL. Chip Friley (2010).

    The MARKAL model identifies the least-cost pattern of resource use and technology deployment over time. It quantifies the sources of emissions from the associated energy system and calculates the system-wide effects of changes in resource supply, technology availability, and energy and environmental policies. MARKAL provides a framework for exploring and evaluating alternative futures and for understanding the role of various technology and policy options. It is a bottom-up, energy technology environmental systems model that finds a least-cost set of technologies to satisfy end-use energy service demands and user-specified constraints. MARKAL also calculates resulting environmental emissions and allows for integration across various energy supply-and-demand sectors, but it is not flexible enough to account for the wide variety of deployment activities that are currently undertaken by the DOE EERE (OpenEI).

21. Newes, E.; Inman, D.; Bush, B. (2011). "Chapter 19 – Understanding the Developing Cellulosic Biofuels Industry through Dynamic Modeling." In progress (Newes, Inman, and Bush 2011).

    The Biomass Scenario Model (NREL 2011) is a systems dynamic model used to study the influence of policies on the development of the renewable fuels energy sector. In BSM 2.0, starch ethanol and cellulosic ethanol via biochemical and thermochemical conversion technologies are considered. Additionally, the BSM includes dynamic feedstock supply curves (POLYSYS estimates), feedstock supply logistics, and downstream distribution and use modules. In BSM 3.0, fungible fuels (algae to diesel/jet via hydrodeoxygenation, sugar fermentation to butanol and to gasoline/diesel/jet, pyrolysis/upgrading to gasoline/diesel/jet, natural oil hydrotreating, gasification/FT synthesis to diesel/jet, and gasification/methanol synthesis/MTG to gasoline) will be added to the conversion module.

Appendix B: Description of the Biomass Allocation and Supply Equilibrium (BASE) Model

B.1. Introduction to the BASE Model

To understand the role that biomass may play in a wide range of future scenarios, numerous models have been developed to project future biomass utilization, with each model having its own system boundary and scope. Energy-economic models with large geographic and sectoral scope are used to provide an overall perspective across many sectors of the world or national economy, however, they typically do not have a great deal of technological, resource, and regional detail. Models with rich technological and regional detail have been developed, but they are normally devoted to a single sector and are often not designed to address the issue of biomass allocation between sectors. Examples include the Biomass Scenario Model (BSM), which simulates biomass resource production and biofuel demand and consumption in the United States and the Regional Energy Deployment System (ReEDS) model, which is a U.S. electric sector capacity expansion model. In these models, the entire biomass resource is typically available for the sector of focus (e.g., for biofuels or biopower), or the biomass supply is statically reduced to represent biomass demand from other sectors. Models that directly address biomass allocation across sectors do exist but often do not address the multiple pathways that are being considered to convert biomass to biofuels, or they often do not explicitly represent different types of biomass feedstock. It is important to note that all of the classes of models described above were designed and tuned to answer particular questions, and, as such, the omissions described above are appropriate given the scope of those questions.

This section describes the purpose, methodology, and necessary inputs for the equilibrium model for biomass allocation and utilization developed for this analysis. The model is referred to as the BASE model and is intended to estimate biomass market equilibrium scenarios to test the effects of potential technology and policy changes. The market allocations projected by BASE may not occur due to regulation, access to capital, market evolution, and many other temporal reasons (e.g., retirement rates of and/or replacement of existing stock, conservative business decisions, uncertain and changing policies, and lack of achievement of n^{th} plant projections due to lack of learning). It also does not provide snapshots of future scenarios or the incremental changes to fuel and power markets. As such, the BASE model is not intended to be a replacement or improvement of the aforementioned classes of models, which start from today's system and project new additions to and retirements of existing stock. Instead, it is designed to help the analysis community identify whether the proposed goals are possible in a mature market scenario. The BASE model will also give an estimate as to whether liquid fuels can compete with other potential uses of biomass on a price basis and estimate the price of feedstock paid under these circumstances (which has implications for the viability of feedstock production by farmers).

The BASE model finds an equilibrium state of the U.S. transportation and electricity sector, and based on this equilibrium state, finds the consumption and price of biomass feedstocks. The market equilibrium state is found iteratively and relies on detailed input data of full life-cycle costs. The market shares for biomass and the allocation between the different fuels and markets are determined based on levelized costs of energy (fuel or electricity), which account for many of the costs and losses that incur from the farm or field to the end user. These costs include feedstock costs, biomass transport and logistics costs, conversion costs, fuel transport costs, and any assumed prices to GHG emissions. The following sections describe the BASE model methodology, structure, and data inputs.

B.2. General Description

As described previously, the BASE model estimates market equilibrium scenarios under assumed mature market conditions and input data provided to the model. The equilibrium scenarios are found through an iterative process, which is represented by the flow diagram in Figure B.1. The BASE model is a MatLab scripting program with data input and output from Microsoft Excel. In addition, the BASE model was designed for short runtimes to enable users to evaluate many scenarios and explore large regions in parameter space, given the large uncertainty with the input parameters and future market conditions. Multiple technologies in the electricity and transportation sectors are represented in the BASE model, which includes detailed representation of biomass technologies and resources.

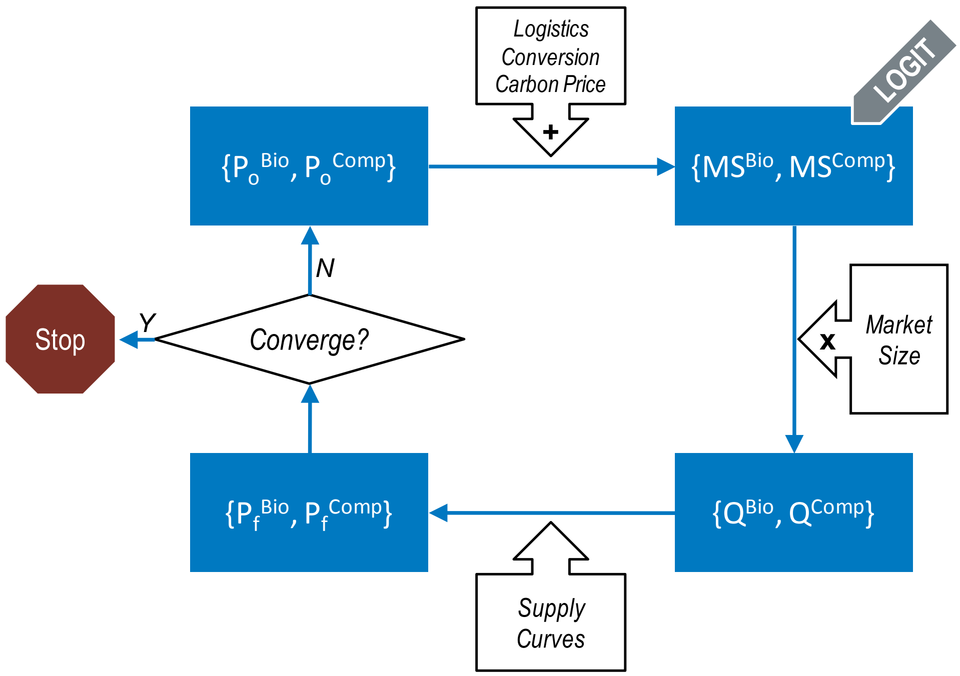


Figure B.1. BASE model structure

Figure B.1 summarizes the BASE model structure and iterative flow, which begins with the upper left box, where initial "guess" prices of biomass (P_o^{Bio}) and competing energy sources (P_o^{Comp}) are established. Next, market shares for biomass (MS^{Bio}) and the competing energy sources (MS^{Comp}) are determined based on the initial "guess" prices. For biomass, the prices (P_o^{Bio}) represent the feedstock prices only, and costs associated with biomass logistics and transport, fuel conversion, and fuel transport are added before the market share algorithm. Carbon prices can also be factored in the market share algorithm for both biomass and competing sources. It is important to note that the BASE finds equilibrium solutions between supply and demand for biomass markets, but not for the electricity and fuel markets. In the electricity and fuel markets, market sizes are exogenously defined and used in the model. In other words, the total quantity of energy sources [sum of biomass (Q^{Bio}) and competing energy sources (Q^{Comp})] are exogenously defined. The market shares, and therefore the amount of biomass consumed, are determined through the results from the market share algorithm based on the exogenously defined fuel and electricity market sizes. Based on these quantities established by the previously determined market shares and the supply curves used for biomass and other energy sources, final prices (P_f^{Bio} and P_f^{Comp}) are found and compared with the initial "guess" prices (P_o^{Bio} and P_o^{Comp}). The equilibrium solution is found when all convergence criteria are met for all biomass feedstocks and competing energy sources simultaneously. If convergence is not achieved, the iterative process is repeated with new "guess" prices based on the previously determined final prices.

B.3. Issues Outside of the Scope of BASE

The BASE model is a simple representation of mature markets and, as such, does not incorporate many issues that affect real markets. Those issues include:

- The competitive advantage of existing stock and infrastructure. One example is co-firing biomass in coal electricity-generation plants. Because the capital costs have already been paid, biomass-generated electricity has a cost advantage in those situations. That advantage is not included in this analysis.
- Regional effects. National averages are used throughout this analysis, so regional opportunities (e.g., where biomass is plentiful) are not included.
- Demand quantities are set for electricity and the fuel markets; as a result, response to price effects and rebound effects are not included in the BASE model. In addition, other technologies that could affect the market size such as plug-in hybrid electric vehicles (PHEVs), liquefied natural gas (LNG) vehicles, compressed natural gas (CNG) vehicles, and hydrogen fuel cell electric vehicles (FCEVs) are not included in the model.
- Other non-price drivers (e.g., marketing as a green fuel, oxygen content requirements, availability of capital for the investment, and the effect of uncertainty on investment).

B.4. Biomass Resources, Fuels, and Markets

A wide variety of biomass feedstocks, fuels, and markets are represented in the BASE model. As a result, the scenario results from BASE provide detailed and specific deployment projections for each feedstock, fuel, and market.[10] Table B.1 shows a matrix of feedstocks and their possible contributions to different fuels and markets.

Table B.1. The Biomass Feedstocks, Fuels, and Markets Represented in the BASE Model

Note: An "X" identifies the feedstocks that can be used for each fuel and market.

Market	**Electricity**	**Gasoline**			**Diesel/Jet Fuel/Bunker Fuel**			
Fuel	Biopower	Ethanol	Butanol	Pyrolysis Gasoline	Pyrolysis Diesel	FT Diesel	Biodiesel	Algal Diesel
Forest Residue	X	X	X	X	X	X		
Short-rotation woody crop (SRWC)	X	X	X	X	X	X		
Agricultural Residue	X	X	X	X	X	X		
Switchgrass	X	X	X	X	X	X		
Corn		X	X					
Soybean							X	
Algae								X

[10] All deployment scenarios represent assumed equilibrium or mature market conditions.

The biomass feedstocks represented in the BASE model include forest residues, short-rotation woody crops (SRWC), agricultural residues[11], switchgrass[12], corn, soybean, and algae. These feedstocks can be converted to biofuels or electricity. Separate end-use markets are treated in the BASE model, namely the electricity, gasoline, diesel, jet fuel, and bunker fuel markets. For biofuels, the BASE model distinguishes between a variety of feedstock/fuel combinations. Fuels include ethanol, butanol, and pyrolysis gasoline that are competed in the gasoline market and pyrolysis diesel, FT diesel, and biodiesel that are competed in the diesel, jet fuel, and bunker fuel markets. Table B.1 shows feedstocks that can be used in each conversion pathway, where an "X" in a matrix element denotes the conversion possibility represented in the model.

B.5. BASE Model Inputs

As in any model used for scenario analysis, the input data plays an important role in determining the outcome scenarios from the BASE model. One of the unique features of BASE is its consideration and representation of detailed biomass data that nearly encompasses the full life cycle of the end-use fuel.[13] Where applicable and available, this data is distinct for each matrix element shown in Table B.1; through its data inputs, the BASE model distinguishes the differences between the different feedstocks and their conversion to end-use fuels at every step of this conversion pathway. The biomass specific data required of the BASE model (and the units) include:

- Feedstock supply curves[14] ($/dry ton (dt) vs. dt)
- Feedstock demand (dt) from other sectors outside of the power or fuel sectors
- Biomass transport and logistics costs ($/dt)
- Feedstock yield [gallon (gal)/dt for biofuels or million British thermal units (10^6Btu)/dt for biopower]
- Conversion costs [$/gal for biofuels or $/megawatt-hour (MWh) for biopower]
- Heat content (Btu/gal)
- Fuel transport costs ($/gal)
- WTW CO_2e emission factors [gCO_2e/Megajoule (MJ)] and petroleum use factors (MJ_{input}/MJ_{fuel}).

It is important to note that many of these data inputs are feedstock- *and* fuel-specific to enable detailed comparison of costs across the different feedstocks and pathways.

The non-biomass competing technologies are not represented in the BASE model with the same level of detail. In general, the levelized costs of the competing fuels are input into the model and used in the market share allocation of BASE. For the transportation sector, the costs of biofuels are compared with the costs of "default" conventional petroleum-based fuels. In particular, the levelized costs of conventional petroleum-based gasoline, diesel, jet fuel, and bunker fuel are input to the model. The BASE model currently does not adjust the prices of these conventional fuels based on variations in demand due

[11] Agriculture residues are composed predominantly of corn stover, therefore, the data used in the BASE model for agriculture residue are commonly based on corn stover data.
[12] Switchgrass is used in the BASE model to represent all herbaceous energy crops.
[13] "Fuel" in this sense refers to liquid biofuels as well as electricity from biopower generators.
[14] Corn and soybean feedstocks are not represented with supply curves due to the complicated interactions with the agriculture sector. Instead, corn and soybean costs are fixed and a range of sensitivity scenarios are evaluated. The "feedstock" costs for algal technologies are included in the conversion costs, therefore no explicit feedstock supply curves or biomass transport and logistics costs were included for algae.

to the lack of available data and complicated global markets for oil.[15] However, the short runtime of the BASE models allows for multiple sensitivities to be evaluated and encompass a range of possible fuel prices. The heat content for the conventional fuels is also input to the BASE model to enable comparison of costs on equivalent gallon bases between the biofuels and conventional fuels. Lastly, the WTW CO_2e emission factors for conventional fuels are input to the BASE model for evaluations of different carbon scenarios.

A greater number of non-biomass competing energy sources are represented in the electricity sector than is represented for the transportation sector. Electricity-generation technologies represented in the BASE model include nuclear, coal, natural gas combined cycle (NGCC), natural gas combustion turbines (NGCT), other renewable energy (RE),[16] and variable renewable technologies, which include wind, photovoltaics (PV), and concentrating solar power (CSP). The electricity sector representation in BASE was largely based on the representation from the NREL's SEDS model (*Stochastic Energy Deployment Systems (SEDS)*, NREL). Appendix J describes the BASE/SEDS electricity sector representation in detail, including the separate load slices and treatment of variable generation. In general, the input data for electricity-generating technologies include costs and performance, which are used to calculate separate fixed and operating costs, including fuel and levelized costs for each of the load slices. Full life-cycle GHG emission factors are also included and used when carbon policies are considered.

Although no price response to demand was included for competing conventional fuels in the transportation sector, the price of natural gas and coal for electricity generation is endogenously adjusted in the BASE model to account for supply and demand pressures. In other words, the BASE model finds equilibrium electric sector consumption and prices for natural gas and coal in a similar manner as for biomass feedstocks. The effective natural gas and coal "supply curves" was based on a linear regression of the reference, high-economic, and low-economic scenarios from EIA's *Annual Energy Outlook 2011*(EIA, 2011a). The methodology used to develop these supply curves were developed and used in NREL's ReEDS model and described in the documentation (Short et al. 2011). The methodology accounts for natural gas demand in the non-electricity (e.g., buildings) sectors.

It is important to note that the BASE model finds the equilibrium state between resource allocation and supply and *not* between supply and demand. In other words, for the different markets represented in BASE, the overall demand for electricity (in megawatt-hours) is exogenously defined *a priori*, as is the demand in gallons for gasoline, jet fuel, and bunker fuel markets. Demand sensitivities are performed by adjusting the market sizes.

B.6. BASE Model Outputs

Although the overall demand for each market (electricity, gasoline, diesel, jet fuel, and bunker fuel) is defined exogenously, the equilibrium market share across energy sources is found in the BASE model. These market shares and the associated demands for the biomass feedstocks and other fuels are outcomes of the model. In addition, BASE finds the equilibrium price for the biomass feedstocks (forest residue, SRWC, agriculture residue, and switchgrass) and competing energy sources (natural gas and coal) represented with supply curves.

The GHG emissions implications of each modeled equilibrium scenario are also reported by BASE. The resultant GHG emissions are then broken down by each category, including by competing technologies and by the separate biomass pathways, independently.

[15] The global and monopolistic nature of petroleum make it difficult to project the degree to which changes in U.S. demand for conventional fuels would influence the prices of the fuels. As such, we decided not to estimate and include price responses to U.S. consumption for the conventional fuels in the BASE model.
[16] The "other RE" category in BASE is representative of all non-biopower dispatchable technologies, including geothermal, hydropower, and concentrating solar power with storage.

B.7. Allocation: Nested Logit Sharing Based on Levelized Costs

The equilibrium market share decision making in the BASE model is determined based on levelized costs only; non-economic barriers and non-equilibrium challenges to deployment are not considered in the model. Market shares for all energy sources, including biomass allocation between fuels and markets, are established strictly by nested logit-sharing based on LCOE of all technologies. The present section defines the LCOE formula, the nested logit structures for the different markets, and the logit share parameters used in the BASE model.

B.8. Levelized Cost of Energy

Equations B.1 and B.2 define the levelized costs of fuel and electricity, respectively, as used in the BASE model. Table B.2 defines the terms in Equations B.1 and B.2 and provides the units of each term used in these two equations.

Equation B.1. Levelized Cost of Energy for Biofuels

$$LCOE_{fuel} = FCR \cdot Cap + OM - Byp + \frac{Log + Feed}{Yield} + FuelTrans + CPrice \cdot CFactor$$

Equation B.2. Levelized Cost of Energy for Electricity Generating Technologies

$$LCOE_{power} = \frac{FCR \cdot Cap + FOM}{8760 \cdot CF} + VOM + Int + \frac{HR \cdot (Log + Feed)}{Yield} + CPrice \cdot CFactor$$

Table B.2. Definition of Terms Used in LCOE Formulas

(presented in Equations B.1 and B.2)

Abbr.		Electricity	Transportation
Cap	Capital Costs	\$/megawatt (MW)	\$/gal
FCR	Fixed Charge Rate	-	-
OM	Operating & Maintenance Costs	-	\$/gal
FOM	Fixed Operating & Maintenance Costs	\$/MW-yr	-
VOM	Variable Operating & Maintenance Costs	\$/MWh	-
Int	Integration Costs	\$/MWh	n/a
Byp	Byproduct Credit	n/a	\$/gal
CF	Capacity Factor	-	n/a
HR	Heat Rate	10^6Btu/MWh	n/a
Log	Biomass Logistics & Transport Costs	\$/dt	\$/dt
Feed	Feedstock Costs	\$/dt	\$/dt
Yield	Yield	10^6Btu/dt	Gal/dt
FuelTrans	Fuel Transport Costs	n/a	\$/gal
CPrice	Carbon Price	\$/metric ton CO_2e	\$/metric ton CO_2e
CFactor	Carbon Factor	metric ton CO_2e/MWh	metric ton CO_2e/gal

The units of $LCOE_{fuel}$ and $LCOE_{power}$ are dollars per gallon ($/gal) and dollars per megawatt-hour, respectively. LCOEs do not include sales taxes or the gas tax. Unless otherwise noted, dollars in the BASE model are 2005 U.S. dollars (see Appendix M). For biofuels, it is important to note that competition with conventional fuels is based on equivalent gallons, therefore, conversions that use the ratios of heat content of the biofuels with the heat content of the conventional fuels is required. As described previously, the electricity market is represented with multiple load slices. The effect of the different load slices is to change the capacity factor, or CF, in the first term of Equation B.2, thereby altering the relative costs between more capital-intensive technologies and fuel-intensive technologies. In addition, while the prices of competing conventional fuels are taken from other sources and input to the model, the LCOE of competing electricity-generating technologies is calculated within BASE using the relevant portions of Equation B.2. More detail on the representation in the electricity section is provided below.

B.9. The Logit Equation

The fundamental equation that determines market shares in the BASE model is the logit equation, Equation B.3. In energy-economic models, logit equations are often used to determine future market shares based on a model-defined utility function. This is unlike pure optimization programs, where winner-takes-all competition is assumed (i.e., lowest cost or highest utility technology takes the entire market share). Instead, logit-sharing spreads the market share between all competitors so that each competitor is given a finite share.[17] Logit-sharing often represents uncertainties with respect to the utility function or the inherent distributions within categories that are represented in the model. Importantly for the BASE model, logit-sharing represents regional aspects with respect to energy suppliers and consumers as well as other variabilities. In particular, although the data used in the BASE model represent aggregate or average U.S. data, regional effects can tilt the competition from one technology to another. Some examples of models where logit equations are used include the Global Change Assessment Model (GCAM)(Clarke et al. 2008) and SEDS.

Equation B.3. Logit Equation that Defines the Market Share of Technology i, MS_i

$$MS_i = \frac{LCOE_i^{-\alpha}}{\sum_j LCOE_j^{-\alpha}}$$

Equation B.3 shows the logit equation used in the BASE model. The market share of each competing technology, MS_i, is a function of the levelized cost of all competing technologies, $LCOE_i$, and the share parameter, α. Other forms of the logit equation are commonly used. For example, whereas the utility function is simply the levelized cost in BASE, other utility functions that account for non-cost factors may be used. Since BASE seeks to represent market equilibrium conditions, these other non-cost factors are not included in the analysis. They need to be overcome for the market to match the model.

The mathematical form of the logit equation can differ from that of Equation B.3. In particular, an exponential form may replace the power-law form of Equation B.3. The primary difference between these two forms is whether or not the overall magnitude of the levelized costs determines if market shares or only the relative costs are important.[18] The power-law function used in BASE only considers relative

[17] Although all competitors will have some market share, the shares can be insignificant depending on relative utility functions (e.g., cost) or timing of share parameter use.

[18] One rationale for using the exponential form of the logit function, where relative *and* absolute magnitudes of the utility functions play a role in determining market share, is that cost differences may be more important for more costly items compared with less costly items. For example, in real estate, differences in tens of thousands of dollars may be important, although the

costs. Further work is needed to identify the effects that other logit equation forms would have on the BASE model results.

Regardless of the form of the logit equation, the choice of share parameter, α, strongly influences the market share results between the competing technologies. In the limit of large α, the logit sharing approaches the winner-takes-all approach, where the technology with the lowest LCOE takes the entire market. In the other limit of zero α, the market share is independent of LCOE and all competing technologies have equal market share. In other words, α represents the degree to which the utility function represents investor decision making. For example, regional variations in technology costs and resource quality across the United States would create a distribution of LCOEs for each given technology instead of a single point estimate. As a result, lower share parameters would be warranted.

For the BASE model, the researchers have chosen to use a share parameter $\alpha=6$ as the default value for all but two of the competition layers.[19] In the competitions between conventional gasoline and biofuels and between conventional diesel and biofuels, $\alpha=12$ was used. The reason for the differences in share parameters is associated with the fungibility of the end-use fuel. More specifically, the heavy infrastructure requirements for light- and heavy-duty vehicles would likely tilt adoption more strongly toward the lesser cost fuel whereas the jet fuel market would switch between fuel types more easily. It is noted that a share parameter of $\alpha=6$ is used in the electric sector and hydrogen sector competition in the GCAM model and $\alpha=10$ is used in the SEDS model electric sector by default. Due to the challenges in quantifying the "right" α, sensitivities are needed to understand the effect that different share parameters may have on the overall scenario results.

B.10. Nested Logit Structure

The challenges associated with selecting an appropriate share parameter are compounded by the fact that the nesting structure of logit sharing also affects the resultant market shares. For example, increasing the number of categories or competitors likely reduces the market share for each individual competitor.[20] The following subsections show the nesting structures and categorizations used in the BASE model for each of the different markets. Further work is needed to identify how different reasonable nesting structures would alter the results from BASE.

B.11. Biofuels Market Logit Competition Structure

For the transportation sector, two distinct nested logit structures are used, one for the gasoline market (Figure B.2), and the other for the diesel, jet fuel, and bunker fuel markets (Figure B.3). At the lowest competition layer (shown in red in Figures B.2 and B.3), the underlying biomass feedstocks that may contribute to each fuel are first competed based on the logit equation described above for each fuel type (shown in orange), independently. Weighted average LCOEs are then associated with each fuel type where the weighting is determined based on the market share from the just-completed logit-sharing at the lowest competition layer. Next, market shares between the different biomass-based fuel types are determined to evaluate a weighted average LCOE of biofuels. Finally, this weighted average biofuel LCOE is then competed with the LCOE of the conventional fuel to find the overall market share of biofuels. Within each logit competition, the LCOE is calculated based on dollars per equivalent gallon.

fractional difference between investments may be small (on the order of a few percentage points). In contrast, purchasing decisions for small items, such as a cup of coffee, are unlikely to depend as strongly on relative costs of one item compared to another even if fractional differences are large (on the order of tens or hundreds of percentages).

[19] Competition layers and nested logit structures are described in the next section.

[20] This is most easily seen in the limit of $\alpha=0$, where all competitors have equal market share independent of utility function values. In this example, if there are two competitors, each would simply realize a market share of 50%. Simply by adding another competitor, the market share would reduce to 33%.

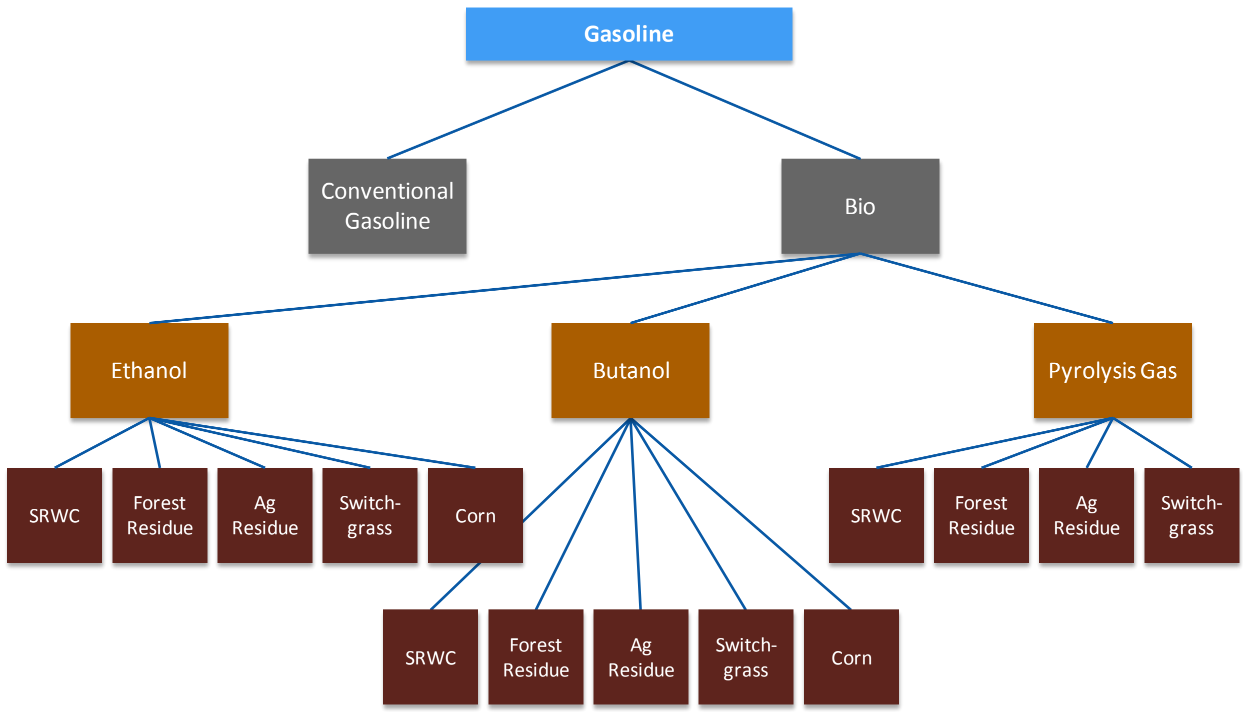


Figure B.2. Nested logit structure for the gasoline market

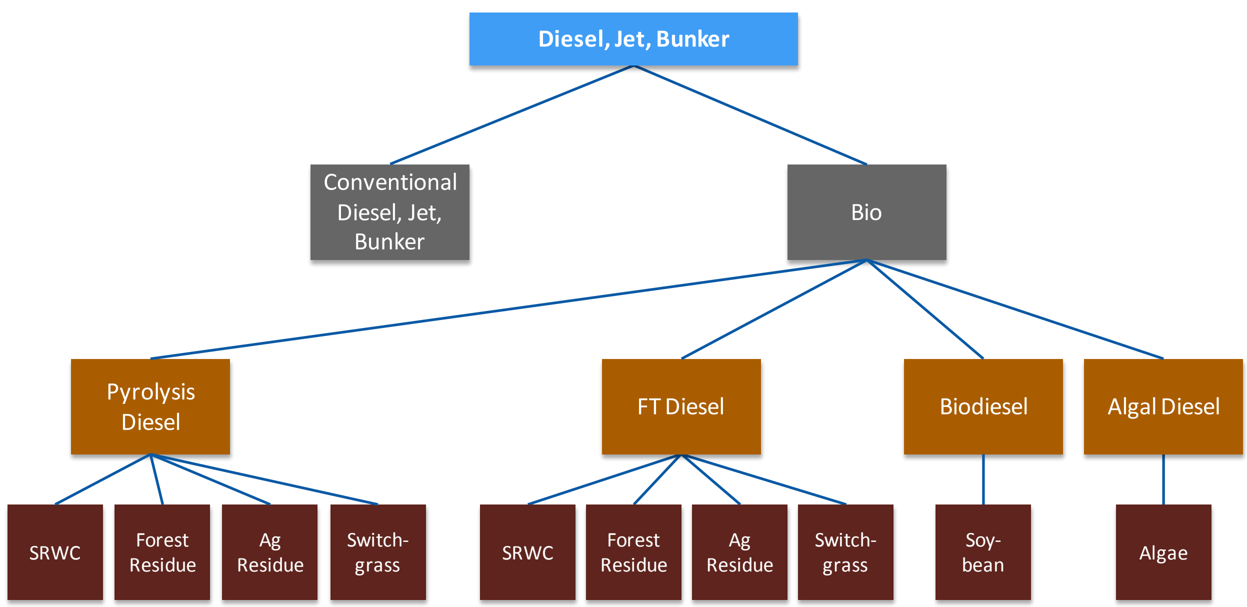


Figure B.3. Nested logit structure for the diesel, jet fuel, and bunker fuel markets

B.12. Electricity Market Logit Competition Structure

Figure B.4 shows the nested logit structure for the electricity market. Conceptually, the electricity market structure is similar to that of the fuels markets, however, there are two important nuances with the electricity market that are not present in the transportation markets: the presence of distinct load slices and the different treatment between dispatchable versus variable generation technologies (e.g., wind, PV, and CSP). The representation of the electricity market in the BASE model is largely based on the treatment in the SEDS model.

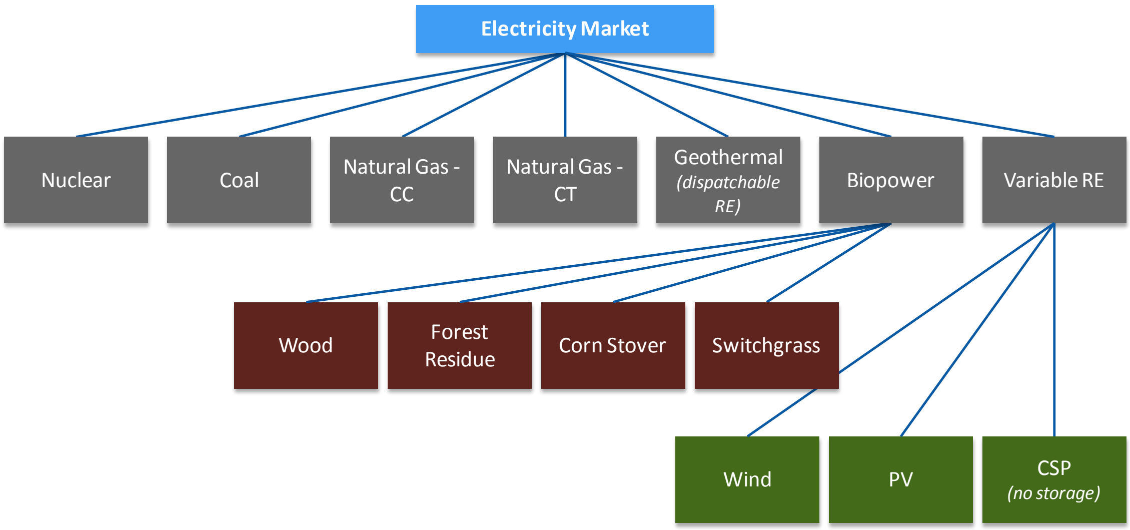


Figure B.4. Nested logit structure for the electricity market

Four separate load slices are used in the electricity market: Baseload, Intermediate, Peak/Intermediate, and Peak. These load slices were designed to capture, at a high level, the economic dispatch decisions in the U.S. electricity markets. Figure B.5 shows how the four load slices are defined using the load duration curve[21] and the amount of annual energy that each load slice covers. The electricity market shares between technologies are found using separate load slice-specific logit sharing between dispatchable technologies. The relative LCOE of the dispatchable technologies differs between load slices due to the different capacity factors assumed within each load slice. Load slices having greater capacity factors tend to favor more capital-intensive technologies (e.g., coal and nuclear), compared with more fuel-intensive technologies (e.g., NGCT).[22] Figure B.5 shows how, in the Baseload load slice, the capacity factors considered for the LCOEs are based on the maximum capacity factor of each plant-type,[23] whereas in the peak load slice, LCOEs are calculated based on a capacity factor of only 4%. As a result, less capital-intensive technologies are favored for peak load technologies.

Biopower is a dispatchable technology and therefore is competed in a similar manner as the other dispatchable technologies. However, before market shares between dispatchable technologies are allocated, the biopower LCOE is determined by first calculating the market shares of the four different feedstocks that are useable for biopower.

[21] A load duration curve is a curve that is derived from ranking the hourly (or other time increment) demand throughout the year.
[22] Due to operational constraints (e.g., ramp rates), nuclear is disallowed from having any market share in the peak load slice. Similarly, natural gas combustion turbines are not given market share in the Baseload load slice.
[23] Due to forced and planned outage rates, capacity factors are less than one.

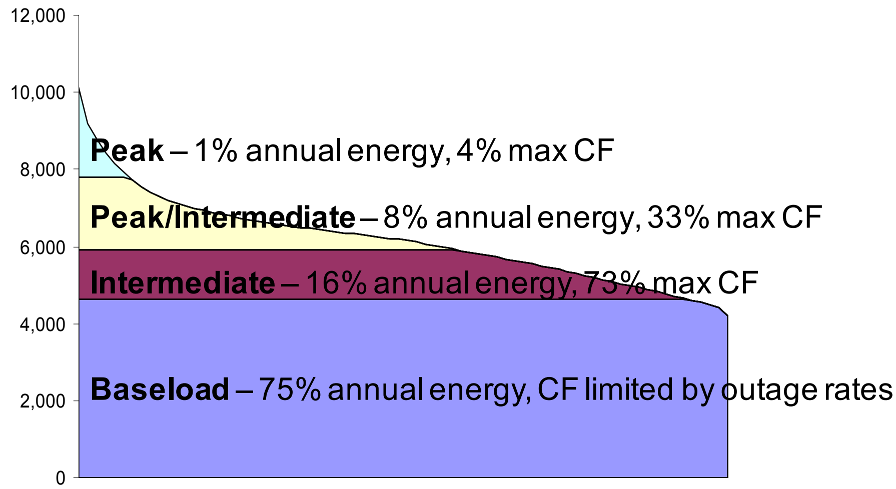


Figure B.5. Load slices in the electricity market

Wind and solar technologies are treated separately from the dispatchables as their power output is determined almost entirely by meteorological conditions and not by system operators. As such, the market shares of these variable generation sources are found by applying Equation B.3 and using the *annual* LCOE of these technologies with the weighted average LCOE of the dispatchable technologies from the Baseload load slice. These calculated market shares are then spread out between the different load slices based on the following distributions: for wind, Baseload = 75%, Intermediate = 16%, Peak/Intermediate = 8%, Peak = 1%; and for solar (PV and CSP), Baseload = 0%, Intermediate = 17%, Peak/Intermediate = 67%, Peak = 16%. These distributions imperfectly represent the greater peak coincidence of solar technologies (compared to wind).

The market shares of the variable generation technologies are subtracted from that of the dispatchable technologies to have normalized market shares in each load slice. Finally, the annual market shares are determined based on the percentage of annual energy shown in Figure B.5 and the market shares by technology within each load slice.

B.13. Self-consistency Between Allocation and Supply Curves

The previous sections describe the equations and logit structure to determine market shares within markets, and allocations of biomass resources to the separate markets. These allocation steps are calculated during each iteration of the BASE model. It is important to remember that what varies between iterations is the assumed price of the underlying biomass feedstock (and the price of some of the competing technologies). In other words, the allocation is a function of the initial "guess" prices at the beginning of each iteration. Before convergence, the amount of feedstock necessary to achieve the calculated market shares corresponds with feedstock prices that do *not* match the initial guess price. Convergence is achieved when the prices for all energy sources do match. Figure B.6 shows a schematic of this process.

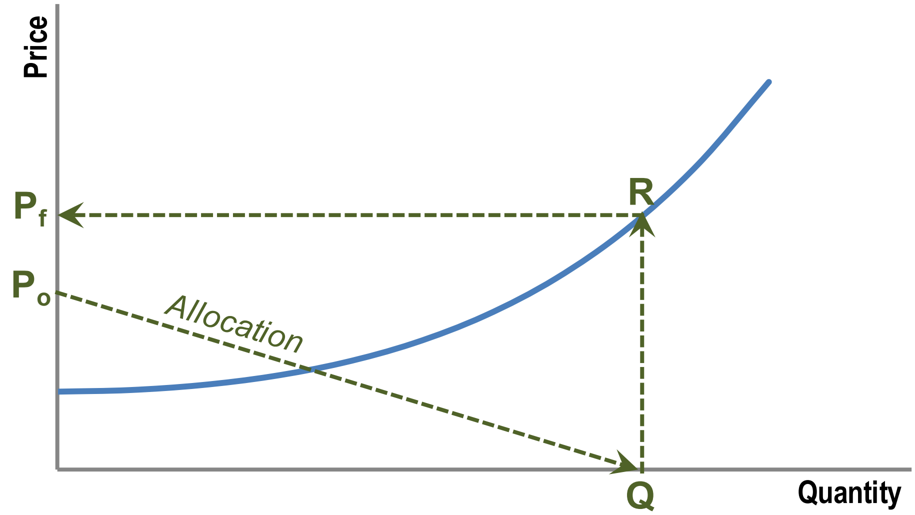


Figure B.6. Feedstock prices are iterated until convergence

The quantity of each feedstock, Q, during convergence verification represents the total feedstock demand across all fuels and markets. In this way, the separate markets are coupled. For example, increased demand for switchgrass for electricity generation may drive up the price of cellulosic ethanol and therefore drive down the demand for cellulosic ethanol in the gasoline market. This reduced demand for cellulosic ethanol may open the market for corn ethanol or for conventional gasoline. By sharing the same resource and supply curve across multiple fuels and markets, the BASE model is able to account for coupling dynamics of supply and demand that will likely be more important as biomass resources are utilized in multiple markets simultaneously.

Finally, although the BASE model only explicitly represents the electricity and transportation sectors, it also accounts for the use of biomass feedstocks in other sectors, including bioplastics. Projections of biomass demand in these other, generally higher-value uses are exogenously defined in BASE and are automatically included in the overall feedstock demand; feedstock supply curves are adjusted to account for the demand for biomass for higher-value uses.

Appendix C: Biomass Resource Supply Curves

The national assessment of biomass resource potential was obtained from the *U.S. Billion Ton Study Update* (BT2) (DOE, 2011), developed by Oak Ridge National Laboratory, as well as from the 2010 U.S. and World Agricultural Outlook, developed by the Food and Agricultural Policy Research Institute (FAPRI) (FAPRI, 2010).

Six different feedstock categories were considered in this study, including agricultural residues, forest residues, grasses, short-rotation woody crops, corn, and soybeans.[24] The dataset for the first four categories was obtained from the BT2, while the corn and soybean potential assessment was obtained from FAPRI. The BT2 and FAPRI datasets were chosen, because they are the most recent and complete data in the literature and they have projections through 2030 and 2019, respectively.

The BT2 data assumes two main scenarios: a baseline and a high yield. The data used in this study was from the baseline scenario, which assumes a continuation of the U.S. Department of Agriculture (USDA) 10-year forecast for the major food and forage crops as well as a continuation in trends toward no-till and reduced cultivation. Energy crop yields assume an annual increase of 1% due to experience in planting and additional R&D.

The BT2 makes use of POLYSIS, an agricultural policy model, and data from the USDA's National Agricultural Statistics Service (NASS) to estimate the supply curves for energy crops and agricultural residues. Forest residues are estimated using resource cost analysis with data from the USDA's Forest Service. The supply curves obtained show the quantity of feedstock that is potentially available for energy use in the United States at different prices. Supply curves are given for each biomass feedstock for each year through 2030. For the year 2050, it was assumed that the supply curve is the same as the year 2030.

Agricultural residues consist of *field residues*, or materials that are left on the field after the crop has been harvested, such as straws and stovers, and *process residues*, or materials that remain after processing the crop into products, such as husks and bagasse. Data for nine crop residues were added together to create the agricultural residues supply curve, including corn, soybeans, oats, barley, sorghum, wheat, cotton, rice, and sugarcane. Residues from the cultivation and harvest of orchards and vineyards are also considered. Animal fats, waste oils, and manure data available in the BT2 were not included in this study.

The agricultural residue supply curve illustrates the cost of the resources at the farm gate. Costs for agricultural resources include the grower payments for crop residue and production costs for energy crops, collection and harvest costs, and cost for transporting the feedstock to the farm gate. Only a limited amount of residues can be collected as biomass; the remaining material conditions the soil and prevents erosion. The data accounts for the amount of residue that is left on the field.

The grasses category includes perennial grasses such as switchgrass, Miscanthus, and sugarcane, and an annual energy crop (high yield sorghum), while the short-rotation woody crops (SRWC) category includes coppice and non-coppice woody crops such as poplar, willow, eucalyptus, and Southern pine. The production cost of these crops includes fertilizer and pesticide usage, equipment fuel, land rent, and labor. Opportunity cost for the use of the land for pasture or other purposes (including pulp and paper) are also taken into consideration. As with the forest residue estimates, resources and land necessary for pulp and paper have been excluded.

Forest residues data was obtained from the USDA Forest Service's Forest Inventory and Analysis Program, Timber Products Output database and calculations based on population numbers. Forest residues include logging residues and thinning materials from integrated operations and forest lands, other removal residues, conventionally sourced wood, unused primary and secondary mill residues, and urban wood wastes. The data used includes federal and non-federal land. Costs for forest residues include

[24] Algae costs were fully included in the conversion costs (see Section 3.6) and, therefore, were not included in this section.

stumpage costs (no stumpage cost is assumed for federal land), harvest costs, chipping costs, and the cost of transporting the residues to the forest roadside (Perlack et al. 2011). Resources necessary for the pulp and paper industry have been excluded from the supply curves (i.e., the supply curves are for resources above and beyond those expected to be used for pulp and paper). The percentage of residues that need to be left on the ground for sustainability is calculated based on slope. For logging residues, it was determined that 30% must be left on-site. For thinning materials, sites with a slope of less than 40% have a retention rate of 40%, sites with a slope greater than 40% and lower than 80% have a retention rate of 30%, and sites with a slope greater than 80% have no residues removed.

Table C.1 shows the BT2 categories and how they were aggregated into the Transportation Energy Future's (TEF's) categories.

Table C.1. Categories for BT2 and TEF

BT2 Categories	TEF Categories
Other Removal Residue	Forest Residues
Conventional Wood	Forest Residues
Integrated Operations	Forest Residues
Treatment Thinnings, Other Forest Lands	Forest Residues
Mill Residue, Unused Secondary	Forest Residues
Mill Residue, Unused Primary	Forest Residues
Urban Wood Waste, Construction, and Demolition	Forest Residues
Urban Wood Waste, Municipal Solid Waste	Forest Residues
Cotton Gin Trash	Agricultural Residues
Cotton Residue	Agricultural Residues
Animal Fats and Waste Oils	N/A
Manure	N/A
Orchard and Vineyard Prunings	Agricultural Residues
Rice Hulls	Agricultural Residues
Rice Straw	Agricultural Residues
Sugarcane Trash	Agricultural Residues
Wheat Dust	Agricultural Residues
Barley Straw	Agricultural Residues
Corn Stover	Agricultural Residues
Oat Straw	Agricultural Residues
Perennial Grasses	Grasses
Sorghum, High Yield	Grasses
Sorghum Stubble	Agricultural Residues
Wheat Straw	Agricultural Residues
Coppice and Non-coppice Woody Crops	SRWC

Figures C.1 – C.4 show the supply curves expressed in terms of total dry short tons available at the field or forest edge at a given cost of production at a national level for 2009, 2020, and 2030. These curves are given in nominal dollars through 2020 and constant 2020 dollars from 2020 through 2050. Figures C.5 – C.8 show the same data in 2005 dollars, converted using the GDP chain-type price index, as described in Appendix M.

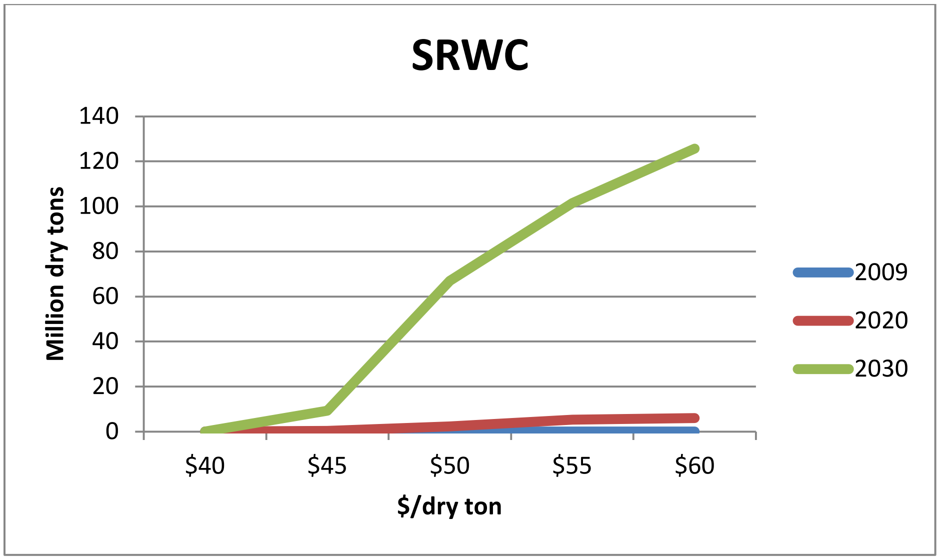


Figure C.1. National SRWC supply curves (nominal costs)
(Source: DOE 2011)

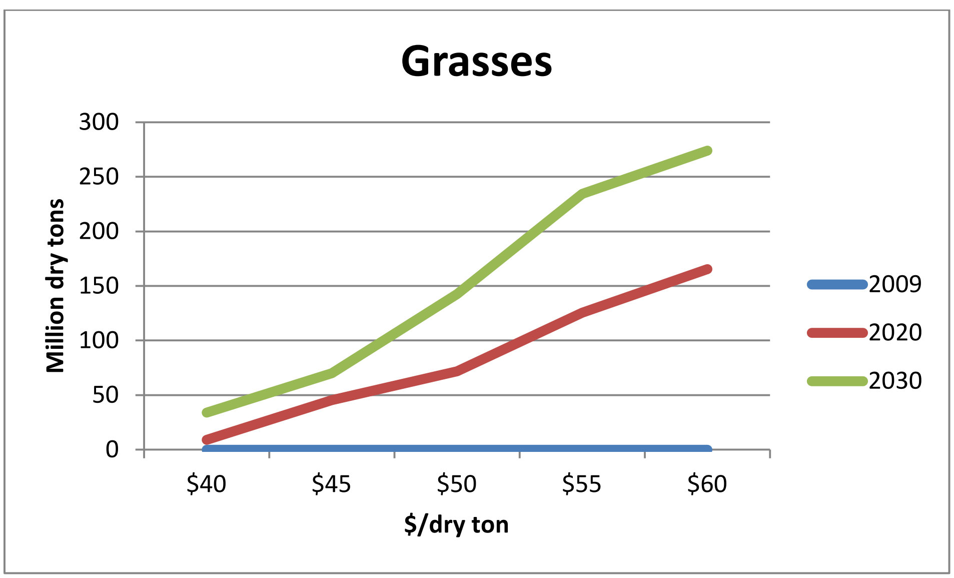


Figure C.2. National perennial grasses supply curves (nominal costs)
(Source: DOE 2011)

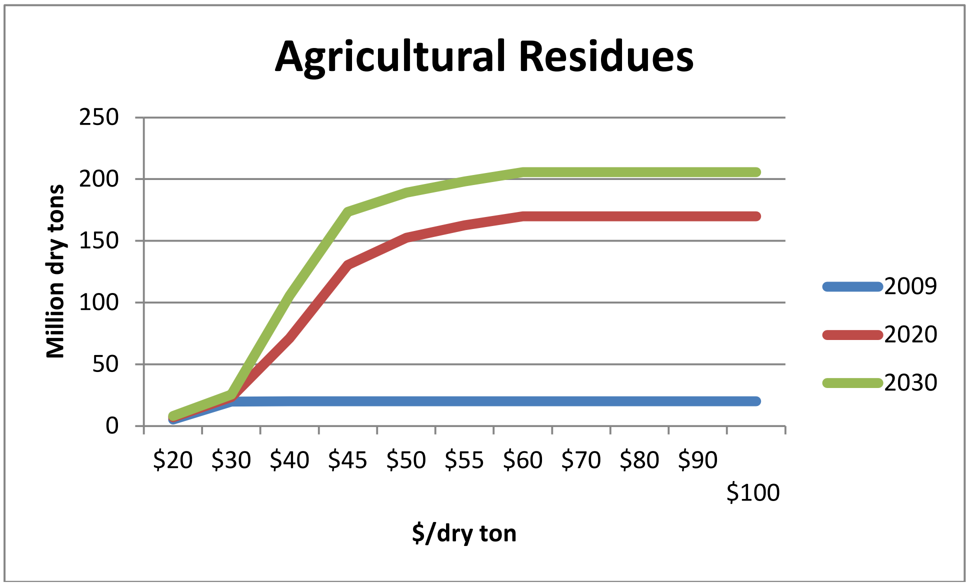


Figure C.3. National agricultural residues supply curves (nominal costs)
(Source: DOE 2011)

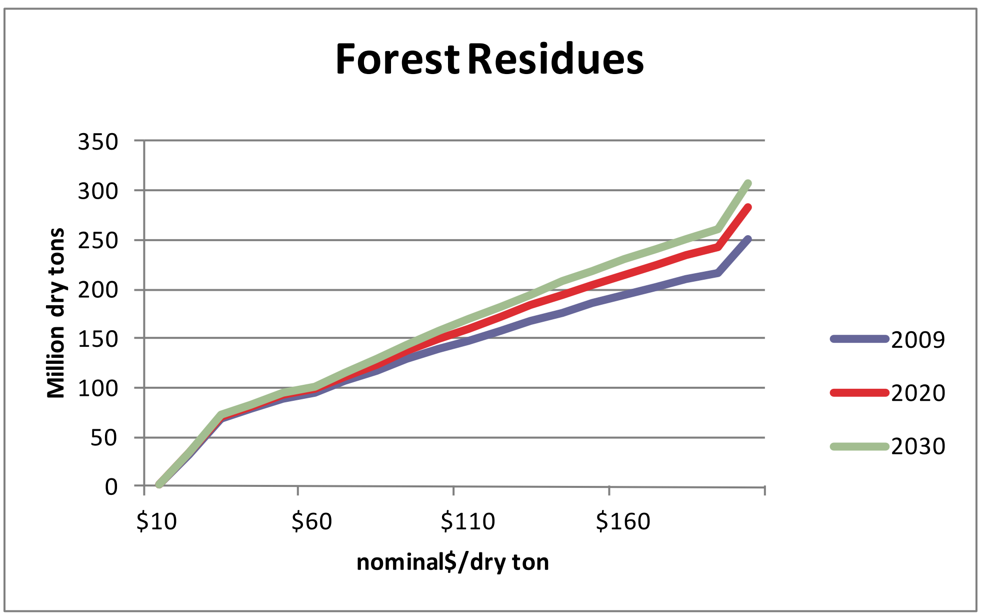


Figure C.4. National forest residues supply curves (nominal costs)
(Source: DOE 2011)

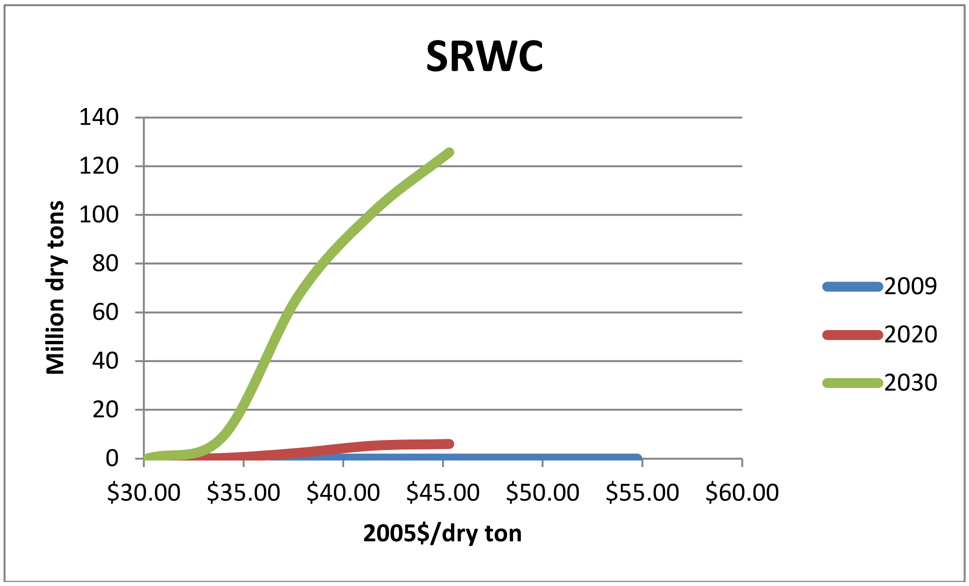


Figure C.5. National SRWC supply curves (conversion data to 2005$)
(Source: DOE 2011)

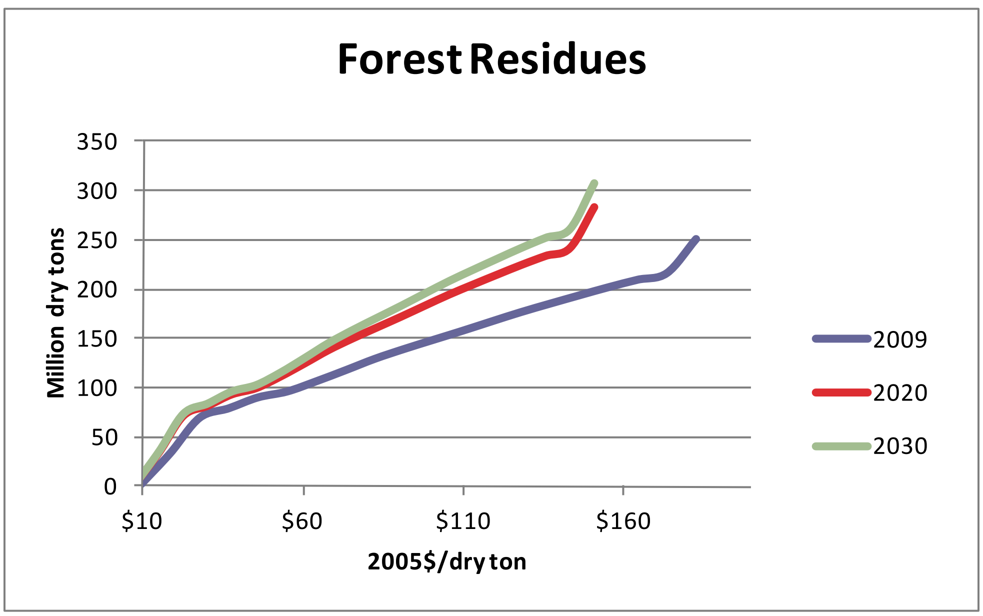


Figure C.6. National forest residues supply curves (conversion data to 2005$)
(Source: DOE 2011)

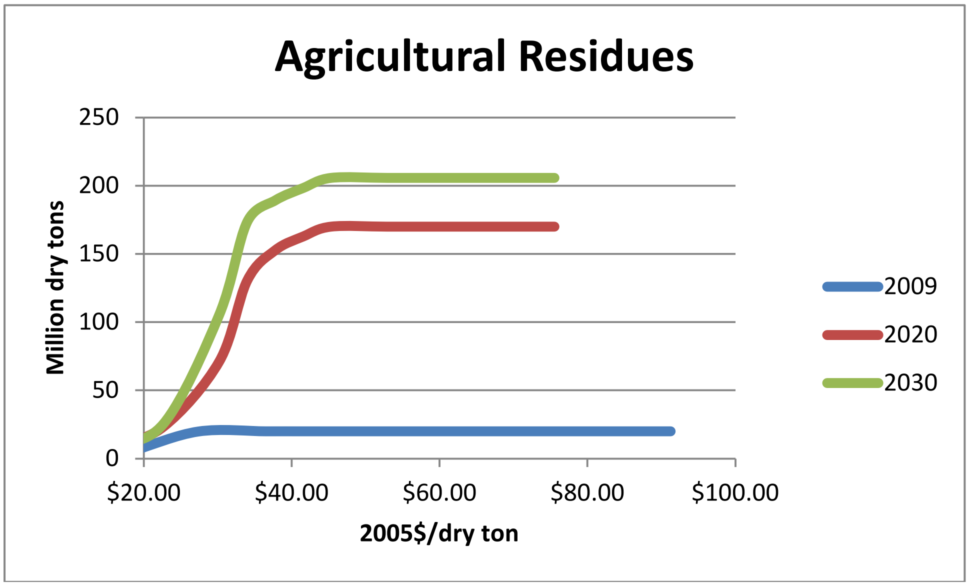


Figure C.7. National agricultural residues supply curves (conversion data to 2005$)
(Source: DOE 2011)

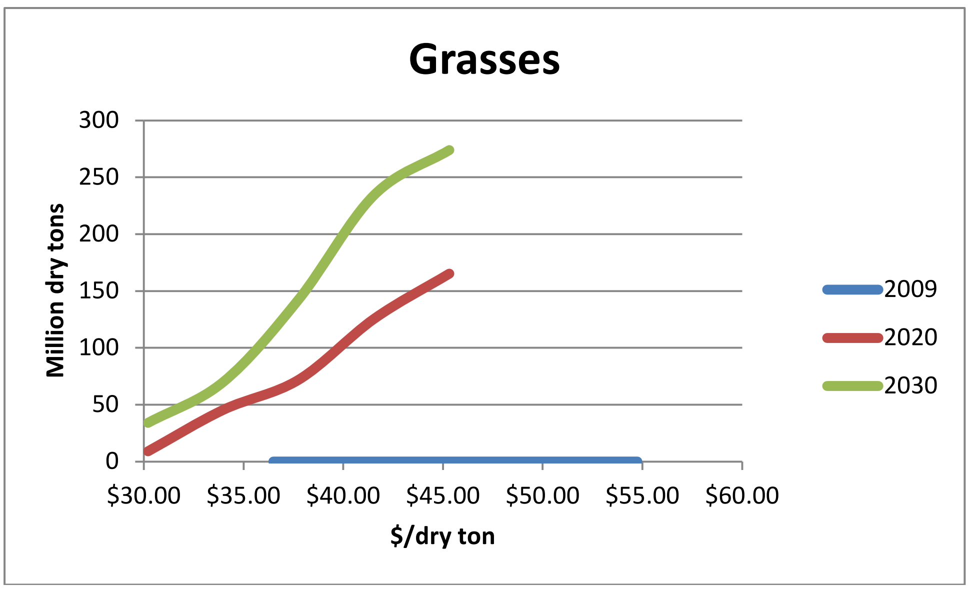


Figure C.8. National grasses supply curves (conversion data to 2005$)
(Source: DOE 2011)

Figures C.9 and C.10 show the same information as in other figures, however, the information is displayed as the data used for the 2020 and 2050 analyses using the BASE model. Because the BT2 only projects supply curves up until 2030, the 2030 curves were used for the 2050 BASE runs. The figures include a near-vertical line at the maximum biomass allowance level, because any additional biomass would increase the price dramatically. Vertical lines are not used, because they would prevent BASE from converging.

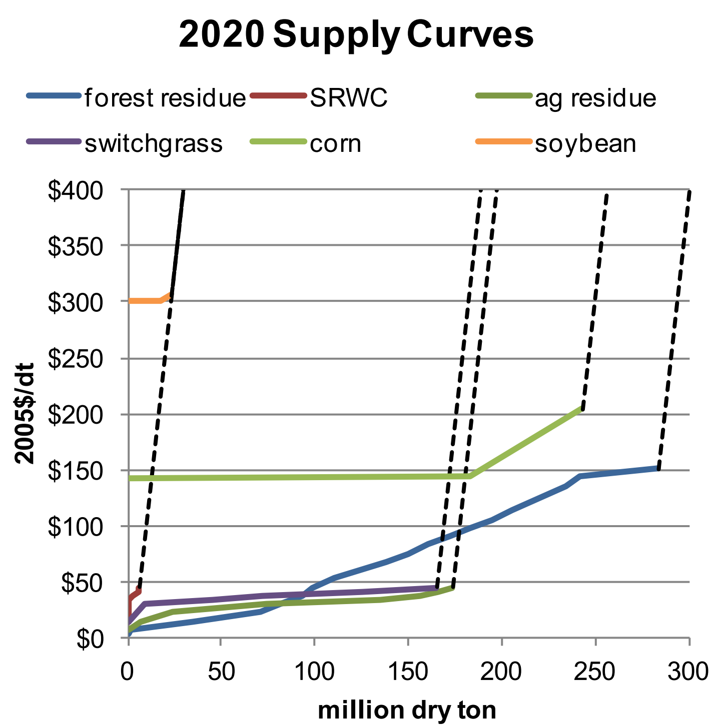


Figure C.9. Supply curves used for the 2020 BASE runs
(Sources: DOE 2011, FAPRI 2010)

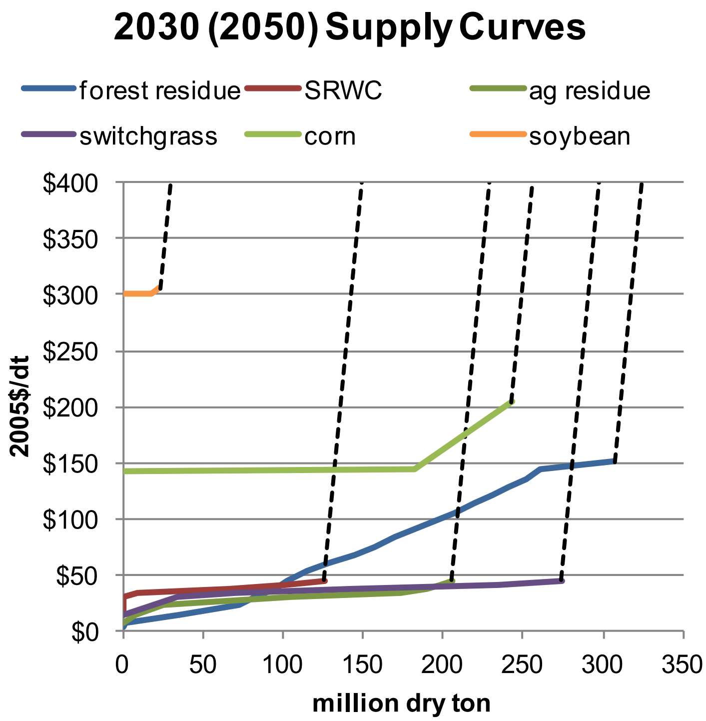


Figure C.10. Supply curves used for the 2050 BASE runs
(Sources: DOE 2011, FAPRI 2010)

Annual estimates of production and prices for corn and soybeans through 2019 were obtained from FAPRI. The study considers yellow corn, grade 2, and assumes a moisture content of 14.5%, while soybean was assumed to have a moisture content of 13%. Tables C.2 and C.3 show the quantity in million metric tons and the price in nominal dollars and 2005$ (converted as explained in Appendix M) for corn and soybeans, respectively, through 2019. Potential and price for all years after 2019 was assumed to be equivalent to those in 2019, because information on later years is not available. FAPRI reports the soybean oil quantity used for biodiesel production. In order to obtain the soybean production (U.S. Soybean Export Council) associated with the production of biodiesel, researchers used a conversion rate of 0.178.[25]

Supply curves for corn and soybeans were constructed for use in the model. In both cases, slope was assumed to be relatively flat ($0.01/dt/Mton) up to the FAPRI annual estimated quantity (for 2019). From the FAPRI quantity to 133% of the FAPRI quantity, supply was assumed to increase by $1/dt/Mton. Above 133% of the FAPRI quantity, the supply curve was modeled with a near-infinite slope, indicating that there was virtually no supply above this point. The same supply curves were used for both 2020 and 2050.

[25] Soybeans = 79.2% soybean meal, 17.8% soybean oil, and 3.0% waste..

Table C.2. Corn Data

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Quantity(million metric tons)	98	112	120	122	124	128	133	136	138	140	142
Price (nominal $/metric tons)	163	168	170	171	173	175	177	177	178	178	176
2005$	149	152	152	151	151	149	148	145	143	140	135

Table C.3. Soybean Data

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Quantity(million metric tons)	5	6	8	9	10	10	11	12	13	13	14
Price (nominal $/metric tons)	362	338	357	359	365	371	375	379	384	388	390
2005$	330	306	319	317	316	316	314	311	308	305	300

C.1. Issues with Supply Curve Projections

The estimation provided by BT2 and FAPRI are dependent on assumptions about variables that can change over time. For instance, conventionally sourced wood potential has high levels of uncertainty at high prices. Elasticity parameters are also based on assumptions that may or may not be correct. Other underlying assumptions include:

- The exclusion of energy crops on land that would require irrigation.
- The exclusion of transportation costs to the biorefinery, feedstock storage costs, and preprocess and handling costs.
- The unpredictability of variables. Because biomass production is a function of soil, climate (precipitation levels and temperature), and available local resources, related variables can change over time—especially with the potential effects of climate change on precipitation patterns (Dai 2011). In addition, the development of diseases could affect crop yields.
- The amount of money a farmer will accept for the sale of crop residues. The amount is uncertain and will depend on market dynamics.
- There is uncertainty regarding the amount of residue that needs to be left on the ground to maintain soil quality. If predictions are wrong, this can affect the soil productivity and therefore reduce the amount of biomass produced.
- Recycling and composting levels can vary over time. In addition, these levels depend on economic and social aspects and have the potential to affect the amount of municipal solid waste available.

APPENDIX D: COMPETING USES OF BIOMASS

Biomass can be used to produce many products beyond transportation fuels and power. In this analysis, those products are given priority. In other words, other uses of biomass are likely to be able to retain profit margins while paying higher prices for biomass than fuel and electricity.

Biomass demand for food, feed, lumber, and pulp and paper were not explicitly accounted for, because those biomass demands were already excluded from the resource supply curves. Likewise, the Energy Information Administration's (EIA's) *Renewable Energy Trends in Consumption and Electricity 2008* (EIA, 2010c) does not report resources necessary for pulp and paper.

Other demands for biomass are not excluded from the resource supply curves. They are identified explicitly and reduce the biomass supply available for fuels and electricity. Those demands include:

- Residential. Consumes wood and wood pellet fuels.
- Commercial. Uses agriculture byproducts/crops, sludge waste, and other biomass solids, liquids and gases, black liquor, wood/wood waste solids and liquids, and corn.
- Industrial, such as:
    - Agriculture, forestry, and mining. Consumes agricultural byproducts/crops.
    - Chemicals and allied products. Consumes other biomass liquids, sludge waste, and wood/wood waste solids.
    - Apparel. Consumes wood and derived fuels.
    - Petroleum refining. Consumes wood and derived fuels.
    - Rubber and miscellaneous plastic products. Consumes wood and derived fuels.
    - Transportation equipment. Consumes wood and derived fuels.
    - Stone, clay, glass, and concrete products. Consumes wood and derived fuels.
    - Furniture and fixtures. Consumes wood and derived fuels.
    - Other non-specified, but related industries. Consumes wood and derived fuels and corn.

EIA's *Annual Energy Outlook* (EIA, 2011a) estimates biomass consumption up until 2035 by residential, commercial, and industrial classification. That information was used for the BASE model and is shown in Table D.1 (U.S. EIA).

For the residential sector, only wood products are consumed under the assumptions (EIA, 2010b). The commercial sector is disaggregated according to EIA's *Renewable Energy Consumption and Electricity Preliminary Statistics.* This sector draws from the BASE model's wood residue, agricultural residue, and corn resource pools (Figure D.1. The industrial sector includes the greatest variety of products and feedstock requirements. These were parsed out according to EIA's *Renewable Energy Trends in Consumption and Electricity 2008* (U.S. EIA 2010c, 2004), which breaks the sector into specific industries and their affiliated feedstock requirements. In addition, this report does not include resources necessary for pulp and paper; therefore, they are not reported in the table. The industrial sector draws from the wood residue, agricultural residue, and corn resource pools in the BASE model.

Table D.1. Projections from the EIA for Annual Biomass Resource Consumption by Competing Uses

(Extrapolated up until 2050 from Annual Energy Outlook 2011) and broken down by use and feedstock type for 2010, 2020, and 2050

	Million Short Tons Consumed per Year		
	2010	**2020**	**2050**
Residential	**31.7**	**31.7**	**31.7**
Wood Residue	31.71	31.71	31.71
Agricultural Residue	-	-	-
Corn	-	-	-
Commercial	**8.5**	**8.5**	**8.5**
Wood Residue	7.58	7.58	7.58
Agricultural Residue	0.49	0.49	0.49
Corn	0.48	0.48	0.48
Industrial	**4.1**	**6.0**	**9.9**
Wood Residue	0.94	1.39	2.28
Agricultural Residue	1.15	1.69	2.78
Corn	1.99	2.93	4.82
Total	**44.3**	**46.3**	**50.1**

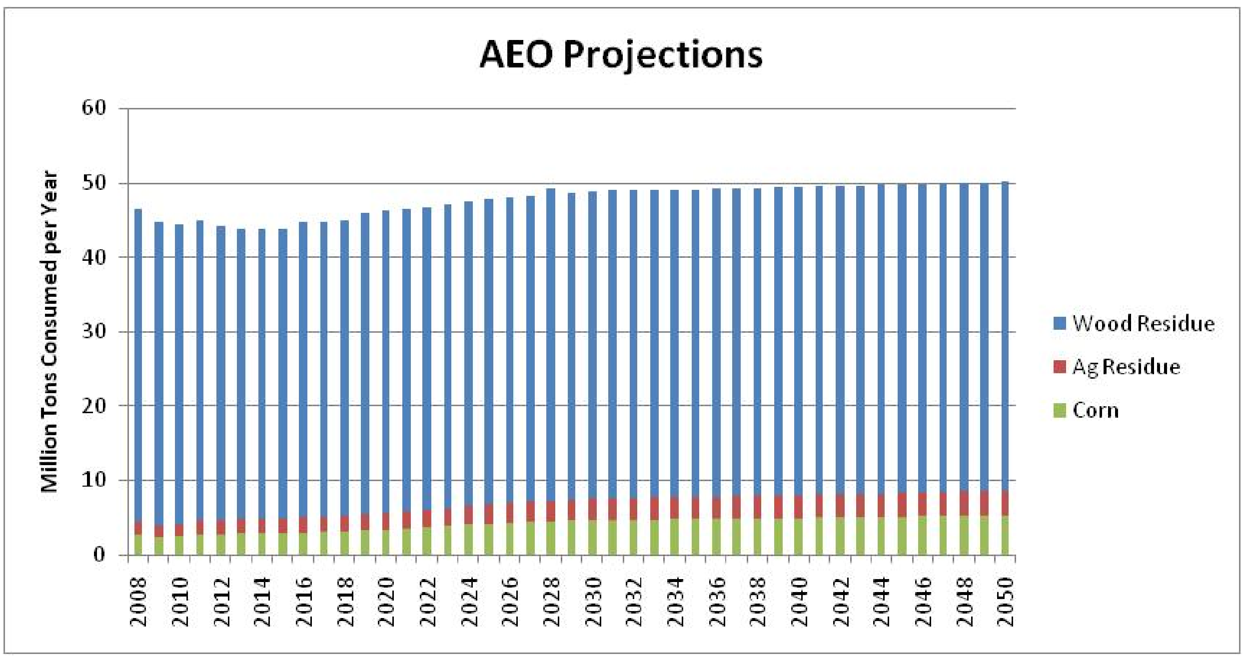


Figure D.1. EIA projections for annual biomass resource consumption by competing uses (extrapolated up until 2050 from *Annual Energy Outlook 2011*) and broken down by feedstock type

(Source: DOE 2011a)

Appendix E: Biomass Transport Costs

For this study, feedstocks are assumed to be supplied to the biorefinery using the conventional bale-based feedstock supply and logistics system (Figure E.1). The conventional bale-based system represents the current logistics system employed by most forage and hay producers in the United States. Within the conventional bale-based system, cost estimates include various machine efficiency, biomass yield, and material loss assumptions during harvest, transport, and storage. The conventional system was chosen for this study, because it is aligned, in terms of costs and physical/chemical composition, with the conversion stage process design reports. The U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Office of the Biomass Program is actively developing more advanced feedstock supply and logistics systems (i.e., uniform format systems) that are expected to take advantage of economies of scale and enable feedstock blending to meet specific refinery needs. The advanced feedstock supply and logistics systems, as currently conceived, involve the use of densification, rail transport, and blending facilities as key aspects of their designs.

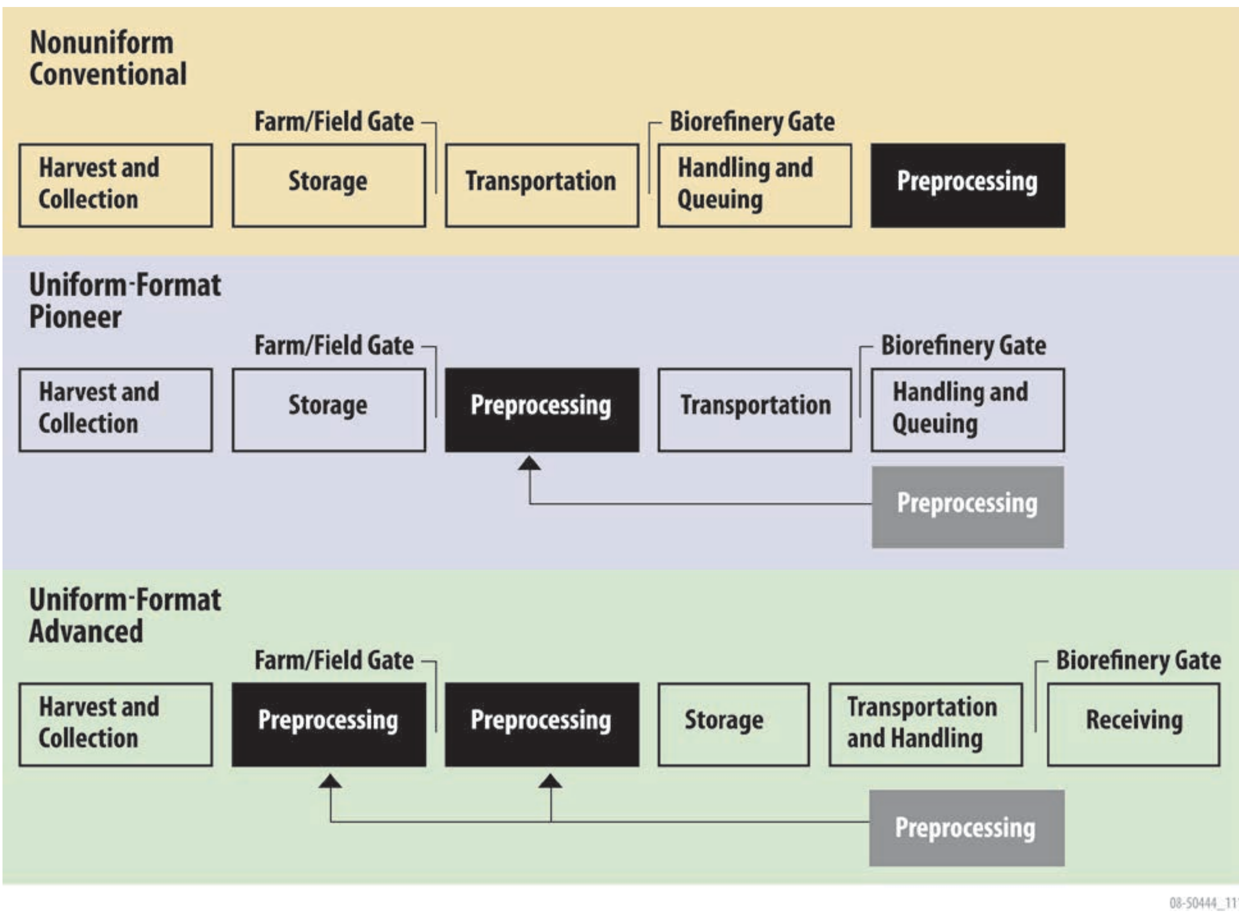


Figure E.1. Schematic diagram showing three feedstock supply and logistics designs developed by Idaho National Laboratory.

Specific unit operations from the field to the biorefinery are shown.

Table E.1 summarizes the material losses associated with specific machinery that is used from harvesting through delivery to the biorefinery. Material lost through handling has a profound effect on delivered costs. The further down the supply chain the loss occurs, the more significant the overall impact is. All costs in subsequent tables are on delivered biomass.

Table E.1. Key Parameters for the Conventional Bale System

SG = switchgrass, CS = corn stover, DM = dry matter, MBtu = thousand Btu, NA = not applicable, T = transportation

	Equipment	Yield (DM ton/acre)		Moisture Content		Energy Use (MBtu/DM ton)	
		SG	CS	SG	CS	SG	CS
Field	180 horsepower Tractor and 15-foot Flail Shredder With Windrower	NA	3	NA	50%	NA	50.1
	Self-propelled Windrower with Disc Header	5	NA	34%	NA	30.9	NA
	275 hp Tractor and Large Square Baler	4	2.4	12%	12%	61.2	61.2
	Self-propelled Loader	4	2.4	12%	12%	13.7	13.7
	Self-propelled Stacker	4	2.4	12%	12%	25.4	25.4
	Weather Protection	4	2.4	12%	12%	0	0
	Self-propelled Loader	3.8	2.28	12%	12%	12.4	12.4
	Sub-Total for Field Operations	-	-	-	-	143.6	162.8
Biorefinery	3-Axle Daycab Tractor with 53-ft Flat Bed Trailer	3.8	2.28	12%	12%	12.6	12.6
	Truck Scale (Weighing)	3.8	2.28	12%	12%	0	0
	Unloading	3.8	2.28	12%	12%	12.4	12.4
	Loading (To Grinder)	3.8	2.28	12%	12%	5.1	5.7
	Grinder In-Feed System (Conveyor)	3.8	2.28	12%	12%	6.1	6.1
	Horizontal Grinder	3.8	2.28	12%	12%	125	125
	Wernerberg 1/4-Grinder	3.8	2.28	12%	12%	90.9	45.4
	Dust Collection System	3.8	2.28	12%	12%	76.5	76.5
	Surge Bin and Conveying System	3.8	2.28	12%	12%	6.1	6.1
	Subtotal at Biorefinery	-	-	-	-	322.1	277.2

Costs associated with the following seven feedstocks are reported in Table E.2: corn stover, switchgrass, corn grain, soybeans, SRWC, forest residues, and algae. These costs are from Idaho National Laboratory's Biomass Logistics Model (BLM) version 6.45 (INL 2011), with the exception of corn grain and soybeans. Published costs were used for corn grain (Benson and Bullen 2007) and soybeans (Reinbott 2012).

Table E.2. Costs Associated with Using a Conventional Feedstock Supply and Logistics System

Covers harvest, transportation, preprocessing, storage, handling, and total costs for seven feedstocks. Costs are reported in 2005 dollars.

Feedstock	Conventional Uniform Design* 2005$ per Dry Short Ton					
	Harvest and Collection	Transportation	PreProcessing	Storage	Handling and Queuing	Total
Stover	13.29	7.47	11.16	5.53	1.14	38.59
Switchgrass	16.53	8.49	11.11	5.37	1.14	42.64
Corn	5.42	5.46	5.80	0.00	0.00	16.69
Soy	5.42	5.46	5.80	0.00	0.00	16.69
Forest Residues	0.00	4.58	21.88	1.24	1.40	29.10
SRWC	18.03	5.47	32.00	1.90	1.49	58.90
Algae	NA	NA	NA	NA	NA	NA

Table E.3 presents the amount of diesel, electricity, and natural gas consumed, per dry short ton, for the feedstocks assessed in the BLM. The energy use presented in Table E.3 includes all energy used from harvesting though delivery to the biorefinery gate. The relationship between diesel, electricity, and natural gas costs was assessed through sensitivity analysis and least-squares regression. For each feedstock in the BLM, the diesel, electricity, and natural gas costs were varied and the model was run. The parameters were varied in isolation as well as simultaneously. The results of the sensitivity analysis were then used to develop least-squares estimates for the parameters such that delivered feedstock cost(s):

[$ dry ton (dt^{-1})] =

α[diesel cost ($ gal^{-1})] + β{electricity cost [$ kilowatt-hour $(kWh)^{-1}$]} + γ[natural gas cost ($ $10^6 Btu^{-1}$)] + ε

Table E.3. Conventional 2012 Feedstock Supply and Logistics Total Costs, Diesel Use and Cost, Electricity Use and Cost, and Natural Gas Use and Cost

Data are from Idaho National Laboratory's BLM version 6.4 (INL 2011). Costs are reported in 2005 dollars.

Feedstock	Total	Diesel		Electricity		Natural Gas	
	$ DT^{-1}	Gal DT^{-1}	$ Gal^{-1}	kW DT^{-1}	$ $(kWh)^{-1}$	10^6Btu DT^{-1}	$ 10^6Btu
CS	38.60	0.24	2.31	8.1	0.05	0	6.87
SG	42.64	0.23	2.31	8.1	0.05	0	6.87
SRWC	58.90	0.39	2.31	7.2	0.05	1.9	6.87
FR	29.10	0.24	2.31	6.7	0.05	1.9	6.87

Abbreviations: CS = corn stover; SG = switchgrass; SRWC = short-rotation woody crop; FR = forest residue; 10^6 = million; dt = dry short ton

Table E.4 shows the parameters that would be used to estimate feedstock delivery costs as a function of energy prices with harvesting included as part of delivery. Since the feedstock cost curves include harvesting (Appendix C), parameters used to calculate the feedstock delivery costs as a function of energy prices are reported in Table E.5.

Table E.4. Results with Harvest and Collection Costs

Data represent the Conventional 2012 Cases for each respective feedstock. Costs are reported in 2005 dollars.

Feedstock	------------- Parameter Estimate -------------			
	ε (Intercept)	α (Diesel Cost Factor)	β (Electricity Cost Factor)	γ (Natural Gas Cost Factor)
Corn Stover	29.08	5.59	0.857	0
Switchgrass	32.12	6.02	1.53	0
SRWC	37.07	8.97	0.888	1.46
Forest Residue	18.0	2.39	7.28	1.65

Where: delivered feedstock cost(s) ($ dt^{-1}) = α[diesel cost ($ gal^{-1})] + β[electricity cost ($ kWh^{-1})] + γ[natural gas cost ($ $10^6 Btu^{-1}$)] + ε

Table E.5. Results without Harvest and Collection Costs.

Data represent the conventional 2012 cases for each respective feedstock and are reported in 2005 dollars.

Feedstock	------------- Parameter Estimate -------------			
	ε (Intercept)	α (Diesel Cost)	β (Electricity Cost)	γ (Natural Gas Cost)
Corn Stover	15.37	4.56	0.855	0
Switchgrass	15.25	4.81	1.80	0
SRWC	19.31	7.32	0.829	1.46
Forest Residue	16.29	2.38	7.28	1.65

Where: delivered feedstock cost(s)($ dt^{-1}) = α[diesel cost ($ gal^{-1})] + β[electricity cost ($ kWh^{-1})] + γ[natural gas cost ($ $10^6 Btu^{-1}$)] + ε

Figure E.2 displays the approximate feedstock logistics and transport costs used for each of the biomass sources. The actual costs are dependent upon the diesel, natural gas, and electricity prices within each BASE run. Note that harvest and collection costs are shown in the figure, but are not included in the BASE calculations, because they are included in the biomass supply curves. Logistics and transport costs for algae are not included, because they are inherently part of the algae growth, collection, and conversion costs discussed in the section on conversion.

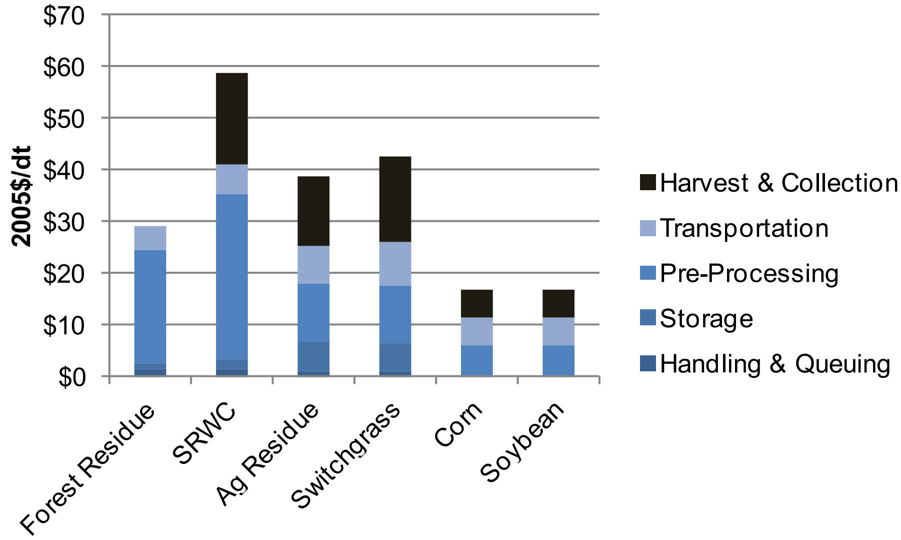


Figure E.2. Feedstock logistic and transport costs
(Sources: Benson and Bullen 2007, Reinbott (2012), Idaho National Laboratory (INL 2011))

Appendix F: Biomass Conversion Costs and Efficiencies

Conversion costs and LCOE calculations were developed for the BASE model as part of the Transportation Energy Futures (TEF) study. These conversion costs were developed for two specific timeframes: circa 2020 and circa 2050. Several liquid fuels and fuel pathways were used, including: ethanol (from both corn and cellulosic biomass), butanol (from both corn and cellulosic), biodiesel (derived from soybean oil), pyrolysis-based gasoline and diesel, hydrogenated diesel, FT diesel, and diesel derived from algae. In this analysis, bio-based diesel products are considered available for jet fuel and bunker fuel without additional conversion costs. Data for each of these fuel pathways was supplied from publicly available sources when possible, and from non-public sources when otherwise not available.

Tables F.1 and F.2 show specific data inputs for 2020 and 2050 analysis years, respectively. Those inputs include total capital costs/project investment, plant capacity (gallon per year), operating costs (OM, $/gallon), byproduct credit (Byp, $/gallon), conversion yield (Yield, gal/dry short ton), and energy content of fuel (Btu/gallon) on a lower heating value (LHV) basis. The value for “Cap” in the LCOE equation for fuel was computed by dividing the total project investment by the plant capacity. The following sections provide references and reasoning behind selection of those references. Within BASE, a single fixed charge rate of 0.132 was assumed for all fuel pathways, but not for electricity, which has a specific fixed charge rate for each conversion technology based on data. This was based upon the capital charge factor computed in NREL’s most recent design reports for cellulosic ethanol. Within these reports, a discounted cash flow analysis was used over an assumed 30-year plant life with a 10% discount factor.

Equation F.1. Levelized Cost of Energy for Biofuels

$$LCOE_{fuel} = FCR \bullet Cap + OM - Byp + \frac{Log + Feed}{Yield} + FuelTrans + CPrice \bullet CFactor$$

The analyses were done using dollars from different years so the GDP chain-type price index was used to convert them to 2005$ (as described in Appendix M).

Table F.1. 2020 Conversion Data

	Cellulosic Ethanol	Cellulosic Butanol	Pyrolysis Gasoline	Pyrolysis Diesel	FT Distillate Diesel	Biodiesel from Soybeans	Corn Ethanol	Corn Butanol	Algal Diesel
Total Capital Cost (million $)	$422.5	$479	$303	$303	$498	$56.25	$94.95	$327.6	$390
Capacity (million gal/yr)	61	25	76	76	32.3	45	45	42	10
Operating Costs¥ ($/gal)	$0.73	$2.04	$1.00	$1.00	$1.28	$0.47	$0.50	$2.05	$3.97
Byproduct Credits ($/gal)	$0.11	$2.20	$0.00	$0.00	$0.20	$0.15	$0.32	$2.55	$0.00
Feedstock Yield (gal/dry short ton)	79.0	32.4	65.0	65.0	47.2	111†	118‡	58.8	N/A
Fuel LCOE* ($/gal)	$2.05	$3.61	$2.14	$2.14	$3.96	$3.94	$1.88	$2.86	$9.12
Year$	2007	2007	2007	2007	2007	2007	2007	2007	2007

¥ *Operating Costs only represent the costs to operate the facility and do not include the feedstock costs.*

* LCOE is calculated within BASE using variable feedstock costs. Results reported here are for example only and use a fixed charge rate of 0.132 and feedstock cost of $40/dry short ton for lignocellulosic biomass, $383/dry short ton for soybeans [$10/bushel, 13% moisture, 60 lb (wet) per bushel], or $168/dry short ton for corn ($4/bushel, 56 lb/bushel, 15% moisture).

† Based on 2.9 gal/bushel

‡ Based on 2.8 gal/bushel

Table F.2. 2050 Conversion Data

	Cellulosic Ethanol	Cellulosic Butanol	Pyrolysis Gasoline	Pyrolysis Diesel	FT Distillate Diesel	Biodiesel from Soybeans	Corn Ethanol	Corn Butanol	Algal Diesel
Total Capital Cost (million $)	$359.1	$407.15	$257.55	$257.55	$423.555	$56.25	$94.95	$278.46	$175
Capacity (million gal/yr)	172	37	212.8	212.8	90.44	45	45	62.16	10
Operating Costs¥ ($/gal)	$0.06	$1.39	$1.00	$1.00	$1.28	$0.47	$0.50	$2.05	$2.00
Byproduct Credits ($/gal)	$0.06	$0.61	$0.00	$0.00	$0.20	$0.15	$0.32	$2.17	$0.00
Feedstock Yield (gal/dry short ton)	98.0	47.9	100	100	59	111	118	87.02	N/A
Fuel LCOE* ($/gal)	$0.68	$3.07	$1.56	$1.56	$2.37	$3.94	$1.88	$2.40	$4.31
Year$	2006	2007	2007	2007	2007	2007	2007	2007	2007

¥ *Operating Costs only represent the costs to operate the facility and do not include the feedstock costs.*

* LCOE is calculated within BASE using variable feedstock costs. Results reported here are for example only and use a fixed charge rate of 0.132 and feedstock cost of $40/dry short ton for lignocellulosic biomass, $383/dry short ton for soybeans [$10/bushel, 13% moisture, 60 lb (wet) per bushel], or $168/dry short ton for corn ($4/bushel, 56 lb/bushel, 15% moisture).

† Based on 2.9 gal/bushel

‡ Based on 2.8 gal/bushel

The current version of the BASE model uses 2005$ consistently so the values in Tables F.1 and F.2 were converted to 2005$ using the GDP chain-type indicators (methodology described in Appendix M). The results of the conversions are shown in Tables F.3 and F.4.

Table F.3. 2020 Conversion Data in 2005$

	Cellulosic Ethanol	Cellulosic Butanol	Pyrolysis Gasoline	Pyrolysis Diesel	FT Distillate Diesel	Biodiesel from Soybeans	Corn Ethanol	Corn Butanol	Algal Diesel
Total Capital Cost (Million $)	$398	$451	$285	$285	$469	$52.9	$89.3	$308	$367
Capacity (million gal/yr)	61	25	76	76	32.3	45	45	42	10
Operating Costs ($/gal)¥	$0.69	$1.92	$0.94	$0.94	$1.20	$0.44	$0.47	$1.93	$3.73
Byproduct Credits ($/gal)	$0.10	$2.07	$0.00	$0.00	$0.19	$0.14	$0.30	$2.40	$0.00
Feedstock Yield (gal/dry short ton)	79.0	32.4	65.0	65.0	47.2	111†	118‡	58.8	N/A
Fuel LCOE* ($/gal)	$1.96	$3.47	$2.05	$2.05	$3.78	$3.91	$1.86	$3.36	$8.58
Year$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$

¥ Operating Costs only represent the costs to operate the facility and do not include the feedstock costs.
** LCOE is calculated within BASE using feedstock costs that vary. Results reported here are for example only and use a fixed charge rate of 0.132 and feedstock cost of $40/dry short ton for lignocellulosic biomass, $383/dry short ton for soybeans [$10/bushel, 13% moisture, 60 lb (wet) per bushel], or $168/dry short ton for corn ($4/bushel, 56 lb/bushel, 15% moisture).*
† Based on 2.9 gal/bushel
‡ Based on 2.8 gal/bushel

Table F.4. 2050 Conversion Data in 2005$

	Cellulosic Ethanol	Cellulosic Butanol	Pyrolysis Gasoline	Pyrolysis Diesel	FT Distillate Diesel	Biodiesel from Soybeans	Corn Ethanol	Corn Butanol	Algal Diesel
Total Capital Cost (million $)	$348	$383	$242	$242	$398	$52.9	$89.3	$262	$165
Capacity (million gal/yr)	172	37	212.8	212.8	90.44	45	45	62.16	10
Operating Costs ($/gal)	$0.06	$1.31	$0.94	$0.94	$1.20	$0.44	$0.47	$1.93	$1.88
Byproduct Credits ($/gal)¥	$0.06	$0.57	$0.00	$0.00	$0.19	$0.14	$0.30	$2.04	$0.00
Feedstock Yield (gal/dry short ton)	98.0	47.9	100	100	59	111†	118‡	87.02	N/A
Fuel LCOE* ($/gal)	$0.67	$2.94	$1.49	$1.49	$2.27	$3.91	$1.86	$2.38	$4.05
Year$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$	2005$

¥ Operating Costs only represent the costs to operate the facility and do not include the feedstock costs.
** LCOE is calculated within BASE using feedstock costs that vary. Results reported here are for example only, and use a fixed charge rate of 0.132 and feedstock cost of $40/dry short ton for lignocellulosic biomass, $383/dry short ton for soybeans [$10/bushel, 13% moisture, 60 lb (wet) per bushel], or $168/dry short ton for corn ($4/bushel, 56 lb/bushel, 15% moisture).*
† Based on 2.9 gal/bushel
‡ Based on 2.8 gal/bushel

F.1. Cellulosic Ethanol

The data for the cellulosic ethanol pathway were derived from a recently released NREL technical report (Humbird et al. 2011) that documented a substantial re-design of a biochemical conversion facility for converting corn stover to ethanol. This conversion data is being utilized for all lignocellulosic feedstocks in the TEF study. The biomass undergoes dilute acid pretreatment, followed by enzymatic hydrolysis, co-fermentation using bacteria, and ethanol purification using distillation and molecular sieve dehydration. The byproduct lignin residue is combusted on-site to provide electricity and power for the biorefinery. The capital cost for this 2000-dry-metric-ton-per-day biomass facility was $422.5 million (year 2007$) and included wastewater treatment, utilities, and so on. With the 79 gal/dry short ton yield, 61 million gallons of ethanol were produced per year. The operating costs of $0.73/gallon included all raw materials, with the exception of feedstock. The byproduct credit of $0.11/gallon was taken for selling electricity back to the grid. The lower heating value (LHV) of ethanol was obtained from the Alternative Fuels Data Center (*Alternative Fuels & Advanced Vehicles Data Center*, NREL).

To forecast improvements for the 2050 case, a different study was referenced (Laser et al. 2009). The Role of Biomass in America's Energy Future (RBAEF) study was geared toward understanding the potential of biomass—in the distant future (2030 or greater)—to contribute to the U.S. energy vision. Within this study, detailed engineering and economic models investigated how improved technology advances, increased scale, process integration, and the role of coproducts could lead to enhanced future economics. Capital costs, operating costs, and process yields were taken directly from this study. Comparing the 2050 (RBAEF) values to the 2020 (NREL) values, the capital costs were 15% lower, the capacity was 280% higher, and the yield was 24% higher (from 79 gal/dry short ton to 98 gal/dry short ton). This cost and yield trend was validated by comparing it to a learning curve analysis that was conducted for several biomass industries such as corn ethanol, sugarcane ethanol, and U.S. biomass power (Beck 2010), and similar trends were seen for the existing industries over time.

F.2. Cellulosic Butanol

The data for the cellulosic butanol process was taken from a recent NREL milestone report that developed techno-economic data for both cellulosic and corn-based butanol (Tao and Aden 2011). This work is an extension of the 2011 NREL cellulosic ethanol design report. Starting with that model, the ethanol fermentation, distillation, and recovery sections were removed and replaced with n-butanol fermentation using a Clostridium strain. The fermentation broth contained a mixture of butanol, acetone, ethanol, and organic acids. Continuous vacuum stripping was used to draw off butanol from the fermentation in order to reduce toxicity effects. Hydrogen was also produced as a byproduct of fermentation and was recovered using pressure swing adsorption. The butanol and other products were separated from one another through a series of unit operations that included distillation, decantation, and dehydration.

For the same 2000 dry metric tons per day feedrate of biomass, 25 million gallons of butanol were produced, because the yields of this process (32.4 gallon per dry short ton) were much lower than for ethanol. The overall capital cost was also quite high at $479 million. Some of this high cost was offset with coproduct credits for acetone ($0.45/lb), ethanol ($0.35/lb), and hydrogen ($1.30/lb). The yield of acetone was 13 gal/dry short ton and the yield of ethanol was 10.4 gal/dry short ton. The lower heating value of butanol was obtained from the Hydrogen Analysis Resource Center (*Hydrogen Analysis Resource Center*).

For the 2050 scenario, an improved yield sensitivity case from the milestone was utilized. This raised the yield from 32 to almost 48 gallons per dry short ton, and raised the butanol production to 37 million gallons per year. Coproduct production was consequently lowered. This reduced the processing costs from the 2020 scenario. Consistent with cellulosic ethanol, a 15% reduction in capital cost was applied to cellulosic butanol for 2050 for this study.

F.3. Pyrolysis Gasoline and Diesel

Fast pyrolysis can be used to produce a mixture of liquid hydrocarbons that are subsequently distilled into separate gasoline and diesel-range fuels. While pyrolysis gasoline and diesel are listed separately in the BASE model cases, the costs are identical, because the same process is used to produce both. The only difference between them is the energy content of the fuel. Because of lack of data on LHV of distilled fuels from pyrolyzed biomass, the finished fuels were assumed to have the same LHV as their respective petroleum gasoline and diesel counterparts.

The costs for pyrolysis were obtained from a PNNL pyrolysis design report (Jones et al. 2009). In this study, costs were developed for conversion of 2000 dry metric tons per day of hybrid poplar. Yields of 100 gallons per dry short ton were calculated, but did not include the natural gas used in steam reforming for hydrogen production. If no natural gas was used, and hydrogen was generated from biomass, the yields would be closer to 65 gallons per dry short ton, which was the yield assumed in the BASE model. No byproduct credits were assumed, because the costs were for a single liquid fuel product (yet to be distilled into gasoline and diesel).

For the 2050 case, researchers used a methodology that is similar to cellulosic ethanol. Yields were increased to 100 gallons per dry short ton, plant production was raised by 280%, and capital costs were reduced by 15%. Other processing costs were held constant between 2020 and 2050.

F.4. Fischer-Tropsch Diesel

Numerous studies have calculated production costs of Fischer-Tropsch (FT) diesel from biomass. This has been an active area of research for over two decades. The data provided for the BASE model was derived from a recent collaboration between NREL, ConocoPhillips, and Iowa State University (Swanson et al. 2010). In this collaborative project, comparative techno-economic analysis was conducted for several fuels pathways, including FT diesel. Techno-economic models were developed based on a conceptual process, using corn stover feedstock. The corn stover was gasified using lower temperature indirect gasification followed by tar reforming, syngas cleanup, fuel synthesis (using cobalt-based FT catalyst in a fixed bed), and hydroprocessing. Hydroprocessing is necessary to crack waxes produced through FT synthesis. Naphtha-range liquids are also produced as a byproduct.

With yields of 47 gallons per dry short ton calculated, 32 million gallons per year of diesel are produced for a biomass feedrate of 2000 dry metric tons per day. The total capital cost is just shy of $500 million. The LHV of FT diesel was obtained from the Hydrogen Analysis Resource Center.

For the 2050 scenario, the same processing costs were assumed. However, the same capacity increase of 2.8x was assumed that was used for cellulosic ethanol, while the capital costs were reduced by 15%. Based on expert judgment, a yield increase of 25% was also assumed for this scenario.

F.5. Biodiesel from Soybeans

Biodiesel from soybean oil and other vegetable oils is a commercial industry in the United States today, although, at less than 750 million gallons per year, it is substantially smaller market than corn ethanol. The biodiesel costs included in this study were also derived initially from the Tao study (Tao and Aden 2009), and then modified to account for current trends. The production costs were given for a 45 million-gallon-per-year facility. As with corn ethanol, the capital intensity factors for biodiesel—total capital investment divided by the annual product produced in gallons per year—have also risen. While this used to be 1.0 or less, expert judgment based on long-term industry interactions considers 1.25 to be a more reasonable value. Yields of 2.9 gallons per bushel of soy (60 lb/bushel, 13% moisture) were used, which equate to 111 gallons per dry short ton. Feedstock costs were much higher than corn ethanol and were based on USDA National Agricultural Statistics Service (NASS) data. In the example LCOE calculation, an assumed $10/bushel value was used, which equates to $383/dry short ton. The energy content of the biodiesel product was also obtained from the Alternative Fuels Data Center (*Alternative Fuels & Advanced Vehicles Data Center*).

Between 2020 and 2050 in the study, no process or cost improvements were assumed. However, USDA and other organizations are researching alternative lower cost feedstocks for biodiesel production, such as Camelina and waste grease.

F.6. Corn Ethanol

Corn ethanol is a commercial industry in the United States, producing over 13 billion gallons of ethanol annually. As such, the production costs are fairly well known and are largely dependent upon feedstock cost (corn). While this data is available from a number of sources, the data for the BASE model comes initially from a study published in 2009 (Tao and Aden 2009) for a 45-million-gallon-per-year plant. The data was subsequently adjusted for this study. Assumed yields were 2.8 gallons per bushel of corn, which equates to 118 gallons per dry short ton. The installed capital intensity of 2.11 was based on expert judgment and used to calculate the capital cost of $95 million. While this capital intensity used to be much lower in the past (~1.25), industry sources indicated that capital intensity has risen, because of the increased cost of steel. For the example LCOE calculation, a feedstock cost of $168/dry short ton was used, based on USDA predictions of corn price circa 2020 of $4/bushel (56 lb/bushel, 15% moisture).

Corn ethanol production costs were assumed to be identical in 2020 and 2050. While the price of corn is expected to rise, the conversion costs are not likely to improve substantially. USDA and other organizations continue to attempt to improve corn ethanol performance through R&D and coproduct development. However, with marginal room for improved yields, this assumption is considered appropriate at present.

F.7. Algal Diesel

Algae, either micro or macro-algae (seaweed/kelp), represent sources of non-terrestrial biomass that can potentially contribute to biofuels production. The data for microalgal-based biofuels (diesel primarily) was obtained from a recently published NREL study (Davis, Aden, and Pienkos 2011). In this study, two algal cultivation methods were modeled and costed: open ponds and closed photobioreactors. Data for the open pond model were used to supply costs for the BASE model.

Algae are grown in unlined ponds, followed by harvesting. To constantly reduce the moisture content, a series of steps is used, including settling, dissolved air floatation, and centrifugation. The oils/lipids in the algae are then extracted through a combination of mechanical and solvent-based extraction. Oil and water is allowed to phase separate and spent solvent and nutrients are recycled within the process. The spent biomass is then sent to anaerobic digestion, where biogas is generated to help power the facility. The oils are subsequently hydroprocessed and upgraded to diesel and naphtha-range hydrocarbons.

For a facility producing 10 million gallons of diesel per year, the capital cost is estimated at $390 million in 2020. Yields (gallon per dry short ton) were not calculated, because the carbon source is CO_2 (instead of biomass), as the algae grow photosynthetically. Improvements for the 2050 scenario were obtained from the sensitivity analysis shown in the published report. In particular, improvements in lipid content and algal productivity were shown to have the greatest impact on cost. With forecasted technological improvements, the processing and capital costs can be reduced from the 2020 costs.

F.8. Fuel Heat Content

As described previously, the BASE model competes all fuels on an equivalent gallon basis, using gallons gasoline equivalent. The heat content (Btu/gal) are provided in Table F.5 for the different fuels.

Table F.5. Heat Content by Fuel Type

Fuel	Heat Content (Btu/gal)
Gasoline	116,090
Ethanol	76,330
Butanol	99,840
Pyrolysis Gasoline	116,090
Diesel	128,450
Jet Fuel	124,614
Bunker Fuel	140,353
Pyrolysis Diesel	128,450
Algal Diesel	128,450
FT Diesel	123,670
Biodiesel	119,550

F.9. Other Potential Biofuels

While a large number of biofuels were included in this study, there were other potential biofuels that were not included. For example, there is a classification of biofuels that has recently become commercial—“hydrogenated fuels”—where natural plant oils are reacted with hydrogen over a catalyst. This serves to saturate double bonds and remove oxygen from the oils, therefore creating high cetane diesel and jet fuels. Dynamic Fuels, LLC, and Neste-oil are two examples of companies that are producing these fuels from a variety of oil feedstocks on a commercial scale. However, these fuels were not included in the TEF project, because good cost models or data were not currently available. Also, the economics were anticipated to largely mirror those of biodiesel (transesterification), where the majority of the cost is associated with the feedstock itself.

In addition, this study did not include gaseous fuels from biomass, such as dimethyl ether (DME), methane, or hydrogen. In order to utilize these fuels, vehicles with substantially different fuel systems are required.

Appendix G: Delivery and Dispensing Costs for Conventional Fuels and Biofuels

Fuel distribution costs were obtained from the *Annual Energy Outlook* for conventional fuels and the TEF fuel infrastructure task for ethanol and biodiesel. Drop-in fuels were assumed to have the same distribution cost as their conventional counterparts.

Table 131 (Components of Selected Petroleum Product Prices) in *Annual Energy Outlook 2011* breaks out the fuel wholesale price, distribution costs, and taxes (energy, federal, and state). The distribution cost segment represents "the part of the supply chain where wholesale gasoline is brought to a retail station and sold to the final consumer. This portion of the gasoline price is the retail price minus the other three price components. It represents both the costs and profits associated with selling retail gasoline to the final consumer." (EIA, *What We Pay for in a Gallon of Regular Gasoline*)

Table G.1 shows the projected 2020 distribution and marketing costs for each fuel category from Table 131 in *Annual Energy Outlook 2011*. Distribution and marketing costs for ethanol and bunker fuel were not reported. The diesel and gasoline distribution cost projections changed by less than 2.5% between 2008 and 2035 (less than $0.005/gal), so they are considered as unchanging for this analysis (i.e., the costs in 2020 and 2050 are the same).

Table G.1. *Annual Energy Outlook 2011* Distribution and Marketing Cost Projections (2009$)

	Marketing and Distribution Costs – 2020 projection
Diesel	$0.18/gal
Gasoline	$0.16/gal
Jet Fuel	$0.00/gal

Since bunker fuel distribution costs were not estimated in the *Annual Energy Outlook*, they were set to the same cost as jet fuel ($0.00/gal) to be consistent with EIA.

Ethanol distribution costs were estimated by the TEF Fuels Infrastructure Team as $0.13/gal (2009$) higher than gasoline. These costs were based on a delivery cost calculator that the team developed, from references (Morrow, Griffin, and Matthews 2006), and from the U.S. Government Accountability Office (GAO, 2007). Therefore, in this analysis, the ethanol distribution cost was set at $0.29/gal (2009$). Biodiesel has distribution issues similar to ethanol, so the distribution and marketing costs for biodiesel were set equal to those of ethanol.

Pyrolysis products, FT diesel, and algal diesel were considered as drop-in fuels for this analysis, so they are assumed to use the same distribution systems as gasoline, diesel, jet fuel, and bunker fuel. As a result, their distribution costs are set equal to the conventional fuels in that market.

Butanol was considered to have similar distribution issues as ethanol in 2020; however, it was also considered to be a proxy for a fermentative drop-in gasoline replacement in 2050. For that reason, the 2050 distribution cost of butanol was set equal to the 2050 distribution cost of gasoline.

Table G.2 shows the distribution and marketing costs for all fuels in 2009$. Table G.3 shows the same information in 2005$, with the conversion made using the gross domestic product chain-type index, as was done throughout this analysis.

Table G.2. Distribution and Marketing Costs Used in this Analysis (2009$)

Fuel Type	Market	2020 Values	2050 Values
Diesel	Diesel	$0.18/gal*	$0.18/gal*
Gasoline	Gasoline	$0.16/gal*	$0.16/gal*
Jet Fuel	Jet Fuel	$0.00/gal*	$0.00/gal*
Bunker Fuel	Bunker Fuel	$0.00/gal*	$0.00/gal*
Ethanol	Gasoline	$0.29/gal	$0.29/gal
Butanol	Gasoline	$0.29/gal	$0.16/gal
Pyrolysis Gasoline	Gasoline	$0.16/gal	$0.16/gal
Pyrolysis Diesel	Diesel	$0.18/gal	$0.18/gal
FT Diesel	Diesel	$0.18/gal	$0.18/gal
Biodiesel	Diesel	$0.29/gal	$0.29/gal
Algal Diesel	Diesel	$0.18/gal	$0.18/gal
Pyrolysis Diesel	Jet Fuel	$0.00/gal	$0.00/gal
FT Diesel	Jet Fuel	$0.00/gal	$0.00/gal
Biodiesel	Jet Fuel	$0.00/gal	$0.00/gal
Algal Diesel	Jet Fuel	$0.00/gal	$0.00/gal
Pyrolysis Diesel	Bunker Fuel	$0.00/gal	$0.00/gal
FT Diesel	Bunker Fuel	$0.00/gal	$0.00/gal
Biodiesel	Bunker Fuel	$0.00/gal	$0.00/gal
Algal Diesel	Bunker Fuel	$0.00/gal	$0.00/gal

*Note: the distribution and marketing costs are included in the prices of conventional fuels reported in Appendix H below, so they are not added separately in the BASE model.

Table G.3. Distribution and Marketing Costs Used in the BASE Model (2005$)

Fuel Type	Market	2020 Values	2050 Values
Diesel	Diesel	$0.16/gal*	$0.16/gal*
Gasoline	Gasoline	$0.15/gal*	$0.15/gal*
Jet Fuel	Jet Fuel	$0.00/gal*	$0.00/gal*
Bunker Fuel	Bunker Fuel	$0.00/gal*	$0.00/gal*
Ethanol	Gasoline	$0.26/gal	$0.26/gal
Butanol	Gasoline	$0.26/gal	$0.15/gal
Pyrolysis Gasoline	Gasoline	$0.15/gal	$0.15/gal
Pyrolysis Diesel	Diesel	$0.16/gal	$0.16/gal
FT Diesel	Diesel	$0.16/gal	$0.16/gal
Biodiesel	Diesel	$0.26/gal	$0.26/gal
Algal Diesel	Diesel	$0.16/gal	$0.16/gal
Pyrolysis Diesel	Jet Fuel	$0.00/gal	$0.00/gal
FT Diesel	Jet Fuel	$0.00/gal	$0.00/gal
Biodiesel	Jet Fuel	$0.00/gal	$0.00/gal
Algal Diesel	Jet Fuel	$0.00/gal	$0.00/gal
Pyrolysis Diesel	Bunker Fuel	$0.00/gal	$0.00/gal
FT Diesel	Bunker Fuel	$0.00/gal	$0.00/gal
Biodiesel	Bunker Fuel	$0.00/gal	$0.00/gal
Algal Diesel	Bunker Fuel	$0.00/gal	$0.00/gal

*Note: the distribution and marketing costs are included in the prices of conventional fuels reported in Appendix H below, so they are not added separately in the BASE model.

Figure G.1 graphically displays the data in Tables G.2 and G.3.

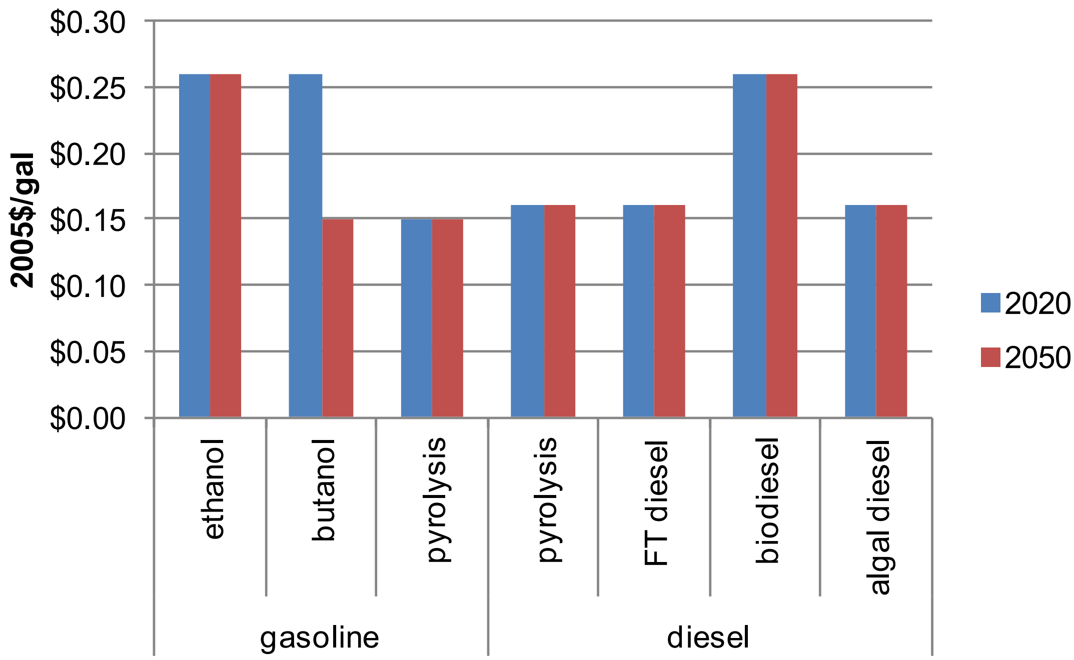


Figure G.1. Fuel distribution and marketing costs
(Sources: DOE 2011a, Morrow et al. 2006, U.S. Government Accountability Office 2007)

Appendix H: Conventional Fuel Price Projections

Projected fuel prices are either taken directly from the EIA's *Annual Energy Outlook 2011*, in the case of the 2020 scenario, or extrapolated from *Annual Energy Outlook* data, in the case of the 2050 scenario. Extrapolation for 2050 is accomplished by adding a yearly increment that is computed as the average slope between 2030 and 2035. Currency is converted from 2009 to 2005 dollars using the gross domestic product Chain-type Price Index (2005=1.000) by dividing by 1.096, as described in Appendix M. All prices are taken from Table 3, Energy Prices by Sector and Source, United States (Reference Case). The data were reported in dollars per million British thermal units and were converted to dollars per gallon of gasoline or diesel equivalent using the conversion factors provided in Table 147 (Reference Case). Researchers subtracted federal and state motor fuels taxes from the prices based on EIA sources (see Table H.1). Researchers used 41 cents per gallon and 47.5 cents per gallon for motor gasoline and diesel, respectively, which was based on data from the Petroleum Marketing Monthly (August 2011) (EIA, 2011b). Furthermore, the *Annual Energy Outlook* lists federal taxes at 4.4 cents per gallon for jet fuel and the number was doubled to 8.8 cents per gallon since average state taxes for gasoline and diesel tend to be roughly equivalent to the federal tax. In the study, bunker fuel was assumed as having the same tax as jet fuel.

Demand elasticities, or the effect of increased/decreased demand on the price of conventional fuels, were considered for this analysis. Inelastic prices were chosen, because the level of elasticity is especially challenging to estimate for long-term trends. Additional review of potential elasticities should be considered in future analysis. Appendix N discusses the findings of this study.

Table H.1. Pricing Data Used in the BASE Model

Fuel	Year	*Annual Energy Outlook* Value/ Extrapolated Value	*Annual Energy Outlook* Units	BASE Value	BASE Units
Gasoline	2020	28.15	2009$/million Btu	2.66	2005$/gallon
Gasoline	2050	32.61	2009$/million Btu	3.15	2005$/gallon
Diesel	2020	25.69	2009$/million Btu	2.75	2005$/gallon
Diesel	2050	29.62	2009$/million Btu	3.25	2005$/gallon
Jet Fuel	2020	22.03	2009$/million Btu	2.68	2005$/gallons diesel equivalent
Jet Fuel	2050	27.02	2009$/million Btu	3.31	2005$/gallons diesel equivalent
Bunker Fuel	2020	14.54	2009$/million Btu	1.73	2005$/gallons diesel equivalent
Bunker Fuel	2050	15.66	2009$/million Btu	1.88	2005$/gallons diesel equivalent

Appendix I: Market Sizes

Data for projected market sizes were either taken directly from the EIA's *Annual Energy Outlook 2011*, in the case of the 2020 scenario, or extrapolated from *Annual Energy Outlook* data, in the case of the 2050 scenario. Extrapolation for 2050 was accomplished by adding a yearly increment that was computed as the average slope between 2030 and 2035. Total electricity sales and transportation-related electricity sales were taken from Table 8, Electricity Supply, Disposition, Prices, and Emissions (Reference Case). They were reported in billion kilowatt-hours and converted to megawatt-hours (see Table I.1). Fuel consumption was obtained from Table 11, Liquid Fuels Supply and Disposition (Reference Case) with the exception of bunker fuel, which is the sum of all residual fuel oil used for domestic and international shipping and military use [which was taken from Table 46, Transportation Sector Energy Use by Fuel Type within a Mode (Reference Case)]. The data in Table 11 were reported in million barrels per day and converted to gallons per year, whereas the data in Table 46 were reported in trillion British thermal units and converted to gallons per year using the conversion factors provided in Table 147 (Reference Case).

The total volume of the gasoline market was estimated by summing the gasoline market size with the E85 market size, once the E85 market size was converted to a gallon gasoline equivalent (gge) basis. The total volume of the diesel market was estimated by summing the diesel market size with the biodiesel and "other biomass-derived fuels" market sizes once the latter two were converted to a gallon diesel equivalent (gde) basis. Market sizes for liquefied petroleum gas and "distillate fuel (other than diesel)" were reported in the *Annual Energy Outlook*, but they were not included in the market sizes for BASE.

Table I.1. Market Size Data Used in the BASE Model

Fuel	Year	*Annual Energy Outlook* Value/ Extrapolated Value	*Annual Energy Outlook* Units	BASE Value	BASE Units
Electricity	2020	3,976	Billion kilowatt-hours	3.98 billion	Megawatt-hours
Electricity	2050	4,990	Billion kilowatt-hours	4.99 billion	Megawatt-hours
PHEV - Electricity	2020	10	Billion kilowatt-hours	10 million	Megawatt-hours
PHEV - Electricity	2050	34	Billion kilowatt-hours	34 million	Megawatt-hours
Gasoline	2020	9.19	Million barrels/day	141 billion	Gallons/year
Gasoline	2050	10.27	Million barrels/day	158 billion	Gallons/year
Diesel	2020	3.9	Million barrels/day	59.9 billion	Gallons/year
Diesel	2050	5.17	Million barrels/day	79.3 billion	Gallons/year
Jet Fuel	2020	1.62	Million barrels/day	24.3 billion	Gallons diesel equivalent/year
Jet Fuel	2050	1.84	Million barrels/day	27.6 billion	Gallons diesel equivalent/year
Bunker Fuel	2020	801.63	Trillion Btu	5.82 billion	Gallons diesel equivalent/year
Bunker Fuel	2050	838.49	Trillion Btu	6.09 billion	Gallons diesel equivalent/year
Biodiesel	2020	0.101	Million barrels/day	1.44 billion	Gallons diesel equivalent/year
Biodiesel	2050	0.132	Million barrels/day	1.88 billion	Gallons diesel equivalent/year
E85	2020	0.219	Million barrels/day	2.65 billion	Gallons gasoline equivalent/year
E85	2050	0.944	Million barrels/day	11.5 billion	Gallons gasoline equivalent/year
Other Biomass-Derived Fuels	2020	0.048	Million barrels/day	683 million	Gallons diesel equivalent/year
Other Biomass-Derived Fuels	2050	0.797	Million barrels/day	11.3 billion	Gallons diesel equivalent/year

Appendix J: Electricity Data

The data used in the electricity-generation technologies and fuels were largely based on EIA's *Annual Energy Outlook 2011* reference scenario projections, however, in some cases, modifications to the data were made and are noted below.

J.1. Electricity-Generation Technology Cost and Performance Data

Table J.1 shows 2020 projected cost and performance data (in 2009$) for the seven electricity-generating technologies represented in the BASE model. Many of the columns [specifically, capital, fixed charge rate, fixed operation and maintenance (O&M) costs, variable O&M, and heat rate columns] represent data that was directly reported in *Annual Energy Outlook 2011* for the reference scenario. In *Annual Energy Outlook 2011*, EIA made projections of the commodity index. To eliminate macro-economic effects on capital costs, the commodity index projections were removed. In other words, the BASE model implicitly assumed a commodity index of 1.0 for all years, whereas *Annual Energy Outlook 2011* projected a commodity index of 1.00894 in 2020 and 0.81886 in 2035. In Table J.1, all columns are directly from the *Annual Energy Outlook*, with the exception of the column labeled "capital net commodity index." That column reflects modifications to the capital cost that have been made for the BASE model to remove commodity index effects. Table J.2 converts the 2020 cost data used in the BASE model to 2005$.

The "maximum annual capacity factor" values in Tables J.1 and J.3 for dispatchable technologies, which include all technologies except wind and solar, were based on data used in NREL's ReEDS model (Short et al. 2011) and consider typical planned and forced outage rates for these plant categories. For the variable renewable generation technologies (wind, PV, and CSP), the annual capacity factors shown were from *Annual Energy Outlook 2011*. The wind capacity factor was based on class 4 resources; the solar capacity factors were based on the straight average across all regions in EIA's National Energy Modeling System, as used in *Annual Energy Outlook 2011*.

Another category of electricity-generation technology, referred to as "other RE," is included in BASE and represents dispatchable renewable resources (but non-biomass), including geothermal, hydropower, and concentrating solar power with thermal storage. Typically, these resources are site-specific in that the developable potential and/or performance quality varies strongly from one region to another. As such, capital costs or capacity factors for these technologies also vary substantially across the country. To account for these variations, electric-sector models typically rely on supply curves to represent these technologies or limit the deployment of these resources. While acknowledging that these effects do exist, and that more detailed modeling may be necessary to accurately model these technologies, the BASE model does not include supply curves for the technologies under the "other RE" category. Instead, BASE uses single-point estimates of technology cost and performance projections for geothermal as the representative, dispatchable non-biomass renewable technology. More specifically, O&M costs assumed were based on projections from *Annual Energy Outlook 2011* and the assumed capital cost was based on an NREL resource assessment (Augustine, Young, and Anderson 2010) for geothermal technologies. In particular, the assumed capital cost was based on a capacity-weighted average over the supply curve for identified hydrothermal geothermal resource (Augustine et al. 2010). This averaging resulted in a capital cost of approximately $6,000/kW (in 2009$), which was applied in BASE for the "other RE" category for both 2020 and 2050. Although this simplified treatment of the dispatchable, non-biomass renewable electricity-generation technologies can be improved, researchers do not expect these simplifications to have an effect on the trends for biomass consumption in biopower presented in this report.

Finally, the BASE model was set up to allow user-defined production tax credits ($/MWh) and integration cost adders ($/MWh). Given the long time horizon of the scenarios examined and the equilibrium nature of the BASE model, the production tax credit was set to zero for all technologies. Integration cost adders for wind and PV were set to $8/MWh (in 2005$), based loosely on estimates from the Eastern Wind Integration and Transmission (EWITS) study, however, since integration costs have been estimated to vary substantially with deployment levels and the flexibility of the electric grid, these values are admittedly uncertain.

Table J.1. 2020 Cost and Performance Data for Electricity Generation Technologies (2009$)

Technology	Capital ($/kW)	Capital net commodity index ($/kW)	Fixed Charge Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Maximum Annual Capacity Factor	Heat Rate (10^6Btu/MWh)
Nuclear	$4,843	$4,800	0.144	$87.69	$2.00	0.90	10.45
Coal	$2,751	$2,726	0.139	$29.31	$4.20	0.85	8.77
Natural Gas-CC	$959	$951	0.133	$14.44	$3.07	0.90	6.37
Natural Gas-CT	$632	$626	0.119	$14.52	$6.90	0.92	9.01
Other RE	-	$6,000	0.109	$107.27	$9.52	0.85	-
Biopower	$3,590	$3,558	0.114	$99.30	$6.43	0.84	13.50
Wind	$2,405	$2,384	0.098	$27.73	$0.00	0.33	-
PV	$4,048	$4,012	0.097	$25.73	$0.00	0.25	-
CSP	$3,401	$3,370	0.104	$63.23	$0.00	0.26	-

Table J.2. 2020 Cost Data for Electricity Generation Technologies Used in the BASE Model (2005$)

Technology	Capital net commodity index ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Nuclear	$4,380	$80.01	$1.83
Coal	$2,487	$26.75	$3.83
Natural Gas-CC	$867	$13.18	$2.80
Natural Gas-CT	$571	$13.25	$6.29
Other RE	$5,474	$97.87	$8.69
Biopower	$3,247	$90.60	$5.87
Wind	$2,175	$25.30	$0.00
PV	$3,660	$23.47	$0.00
CSP	$3,075	$57.69	$0.00

Tables J.3 and J.4 are similar to Tables J.1 and J.2, respectively, however, 2035 cost and performance data were shown instead of 2020. In the BASE model, 2050 scenarios were evaluated using the 2035 cost and performance data provided here. *Annual Energy Outlook 2011* only made projections up until 2035 and no extrapolations beyond 2035 were assumed in the BASE model assumptions.

Table J.3. 2035 Cost and Performance Data for Electricity Generation Technologies (2009$)

Technology	Capital ($/kW)	Capital net commodity index ($/kW)	Fixed Charge Rate	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Maximum Annual Capacity Factor	Heat Rate (10^6Btu/MWh)
Nuclear	$3,423	$4,180	0.143	$87.69	$2.00	0.90	10.45
Coal	$2,118	$2,587	0.139	$29.31	$4.20	0.85	8.74
Natural Gas-CC	$711	$869	0.131	$14.44	$3.07	0.90	6.33
Natural Gas-CT	$456	$557	0.118	$14.52	$6.90	0.92	8.55
Other RE	-	$6,000	0.108	$124.13	$9.52	0.85	-
Biopower	$2,686	$3,280	0.112	$99.30	$5.92	0.84	13.50
Wind	$1,933	$2,360	0.097	$27.73	$0.00	0.33	-
PV	$2,487	$3,037	0.096	$25.73	$0.00	0.25	-
CSP	$2,001	$2,443	0.103	$63.23	$0.00	0.26	-

Table J.4. 2035 Cost Data for Electricity Generation Technologies Used in the BASE Model (2005$)

Technology	Capital net commodity index ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Nuclear	$3,814	$80.01	$1.83
Coal	$2,360	$26.75	$3.83
Natural Gas-CC	$793	$13.18	$2.80
Natural Gas-CT	$508	$13.25	$6.29
Other RE	$5,474	$113.25	$8.69
Biopower	$2,993	$90.60	$5.41
Wind	$2,154	$25.30	$0.00
PV	$2,771	$23.47	$0.00
CSP	$2,230	$57.69	$0.00

J.2. Non-Biomass Fuel Data for Competing Electricity-Generation Technologies

Fossil-fuel and uranium price projections for 2020 and 2050 were also based on *Annual Energy Outlook 2011* projections. More specifically, the uranium price in 2020 was directly taken from the *Annual Energy Outlook 2011* reference case, whereas the 2050 uranium price was based on an extrapolation (using 2025–2035 projections) of the same reference case. Because of the greater degree of elasticity in fossil-fuel prices (especially natural gas), linear supply curves were used for natural gas and coal. The methodology to develop the supply curves are described (Short et al. 2011), and the same supply curves presented here are used in NREL's ReEDS model. In short, fossil-fuel elasticity parameters were derived using a linear regression of fossil-fuel consumption and price across three cases from *Annual Energy Outlook 2011*: the reference case, and high-economic growth and low-economic growth cases. The elasticity parameters represent the increase in per unit price of fossil fuel for each additional unit of electric sector consumption of the fuel. The elasticity parameters were assumed constant over time. In addition to the elasticity parameters, a minimum fixed fossil-fuel price was used to fully define the linear supply curve; the y-intercept of a fossil-fuel supply curve was defined by the fixed price and the slope was defined by the elasticity parameter. The fixed price changes over time and was calibrated to match the *Annual Energy Outlook 2011* reference case consumption and price for all years. To obtain the 2050 supply curve, the fixed price was based on extrapolations from 2025 to 2035 in the *Annual Energy Outlook 2011* reference case.

Table J.5 shows the uranium and fossil-fuel prices and elasticities for 2020 and 2050 in 2009$ (based on the method described above). Table J.6 contains the same data in 2005$. The BASE model uses these values and endogenously finds the equilibrium price for natural gas and coal in each scenario based on their supply curves.

Table J.5. 2020 and 2050 Fossil-Fuel and Uranium Prices (2009$)

Fuel	Elasticity ($/10^{6}Btu per Quadrillion Btu)	Price ($/10^{6}Btu)
2020 Natural Gas	0.353	$2.53
2020 Coal	0.048	$1.24
2020 Uranium	n/a	$0.82
2050 Natural Gas	0.353	$4.85
2050 Coal	0.048	$1.53
2050 Uranium	n/a	$1.30

Table J.6. 2020 and 2050 Fossil-Fuel and Uranium Prices (2005$)

Fuel	Elasticity ($/10^{6}Btu per Quadrillion Btu)	Price ($/10^{6}Btu)
2020 Natural Gas	0.322	$2.31
2020 Coal	0.044	$1.13
2020 Uranium	n/a	$0.75
2050 Natural Gas	0.322	$4.43
2050 Coal	0.044	$1.39
2050 Uranium	n/a	$1.19

Appendix K: Life Cycle GHG Emissions and Petroleum Consumption

Well-to-wheel (WTW) and well-to-tank (WTT) life cycle GHG emissions and petroleum consumption data used in the BASE model are illustrated in Figure K.1 and listed in Table K.1 for the years 2020 and 2050. The primary data source is the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model version 1.8d (*GREET Model: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation*). Supplemental fuel pathways for microalgae-based fuels grown in an open pond were partially generated in the GHGenius model version 3.19a ((S&T)^2 Consultants 2004). Supplemental fuel pathways for pyrolysis-oil-based fuels were partially based on GREET and a SimaPro v.7.2 model of pyrolysis oil processing to gasoline and diesel (Hsu 2011). Table K.2 lists the fuel economies taken from GREET that are used to calculate tank-to-wheel life cycle GHG emissions and petroleum consumption estimates.

Life cycle GHG emissions and petroleum consumption estimates for fuel pathways present in GREET were generated with few changes to default parameters, other than switching among feedstocks. Fuel pathways for the 2020 and 2050 scenarios were both modeled based on default GREET assumptions for 2020, because 2050 default parameters in GREET were not available. The electricity grid for 2020 and 2050 and associated life cycle GHG emission intensities were modeled based on the Renewable Energy Future's (REF) study's 80% renewables projections (Mai et al.). Parameters for specific fuel pathways were modified to reflect conversion efficiencies assumed for 2020 and 2050, as outlined in Section 3.6.

Existing GREET fuel pathways were modified to model several fuel pathways not present in GREET. Lignocellulosic butanol life cycle GHG emissions and petroleum consumption estimates were generated based on modified GREET lignocellulosic ethanol pathways. Modifications were based on data from Tao and (Tao and Aden 2011; Mullins, Griffin, and Matthews 2010). The portion of Hsu's SimaPro model (Hsu 2011) for biomass conversion to pyrolysis oil and then to fuels was modified to reflect pyrolysis fuel conversion efficiencies; outlined in Section 3.6. This data was combined with lignocellulosic feedstock production and fuel distribution data from the GREET model to produce total life cycle GHG emissions and petroleum consumption estimates. Coal- and biomass-based electricity [with carbon capture and storage (CCS)] life cycle GHG emissions and petroleum consumption estimates were modified based on using CCS rates from Fischer-Tropsch diesel pathways. Energy losses from CCS were taken from Spath and Mann {Spath, 2004 #46 to complete modeling of the coal-with-CCS-electricity pathway.

The GHGenius model's algae-based fuel pathways (i.e., renewable diesel and biodiesel) were generally unmodified to produce the WTT results listed in Figure K.1 and Table K.1. Like the GREET model, the electricity grid mix and associated life cycle GHG emissions were modified to reflect the REF 80% renewables scenario for 2020 and 2050. Life cycle GHG emissions and petroleum consumption estimates for 2020 and 2050 were based only on 2020 default parameter assumptions. The available 2050 assumptions were not used in order to parallel 2050 scenarios in the GREET model. Tank-to-wheel life cycle GHG emission estimates for biodiesel and renewable diesel were taken from GREET and combined with GHGenius WTT data to get WTW results.

2020 Life Cycle GHG Emissions

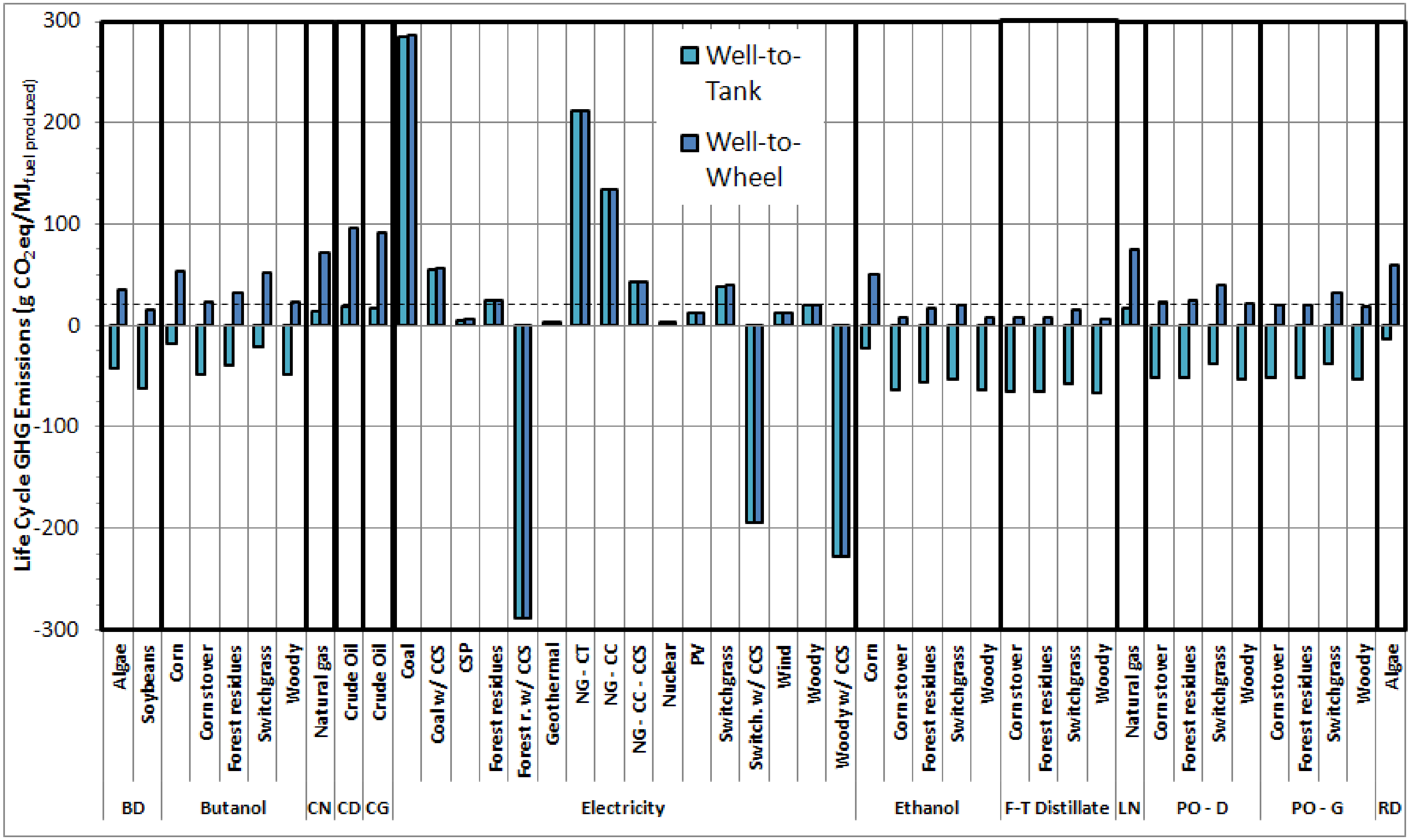
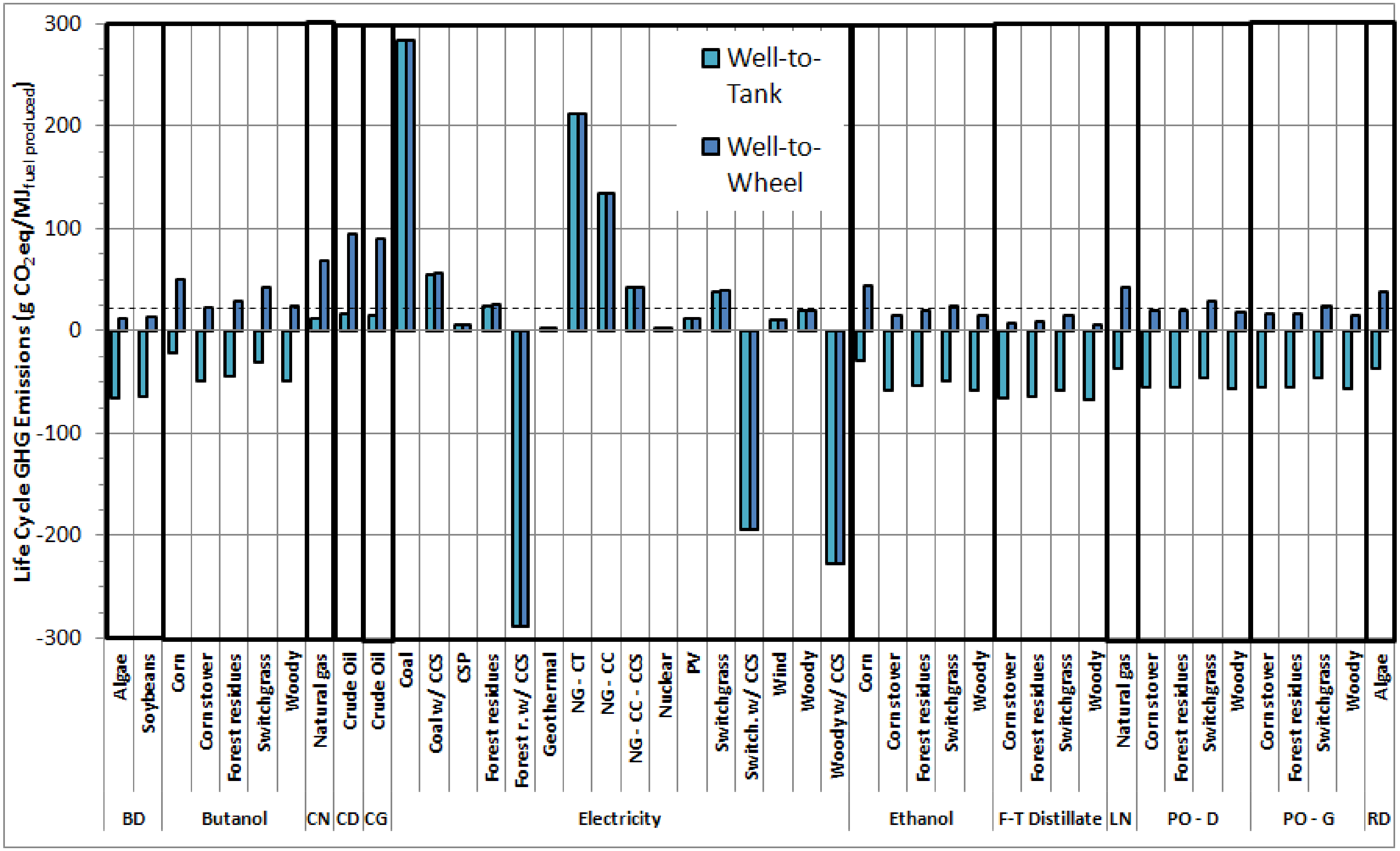


Figure K.1. WTW and WTT life cycle GHG emissions and petroleum consumption estimates used in the BASE model for 2020 and 2050. The dotted line represents an 80% GHG emission or petroleum consumption reduction from gasoline.

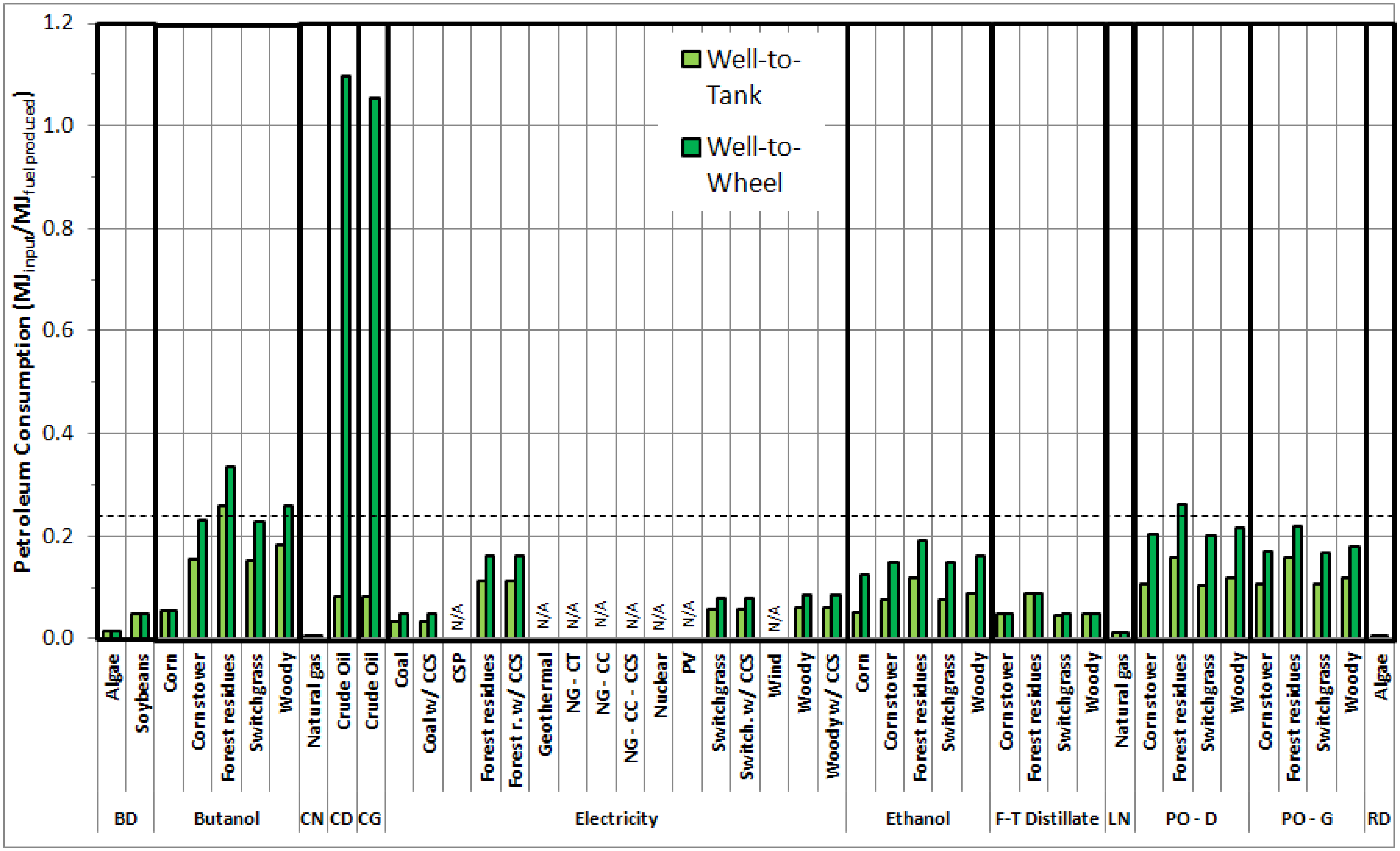
[Sources: Argonne National Laboratory 2011, (S&T)² Consultants 2011, Hsu 2011, Spath and Mann 2004, Mullins et al. 2010, Tao and Aden 2011, Mai et al. 2012]

CNG = compressed natural gas; CD = conventional diesel; CG = conventional gasoline; F-T = Fischer-Tropsch; LNG = liquefied natural gas; PO = pyrolysis oil; RD = renewable diesel; BD = biodiesel

2050 Life Cycle GHG Emissions



2020 Petroleum Consumption



2050 Petroleum Consumption

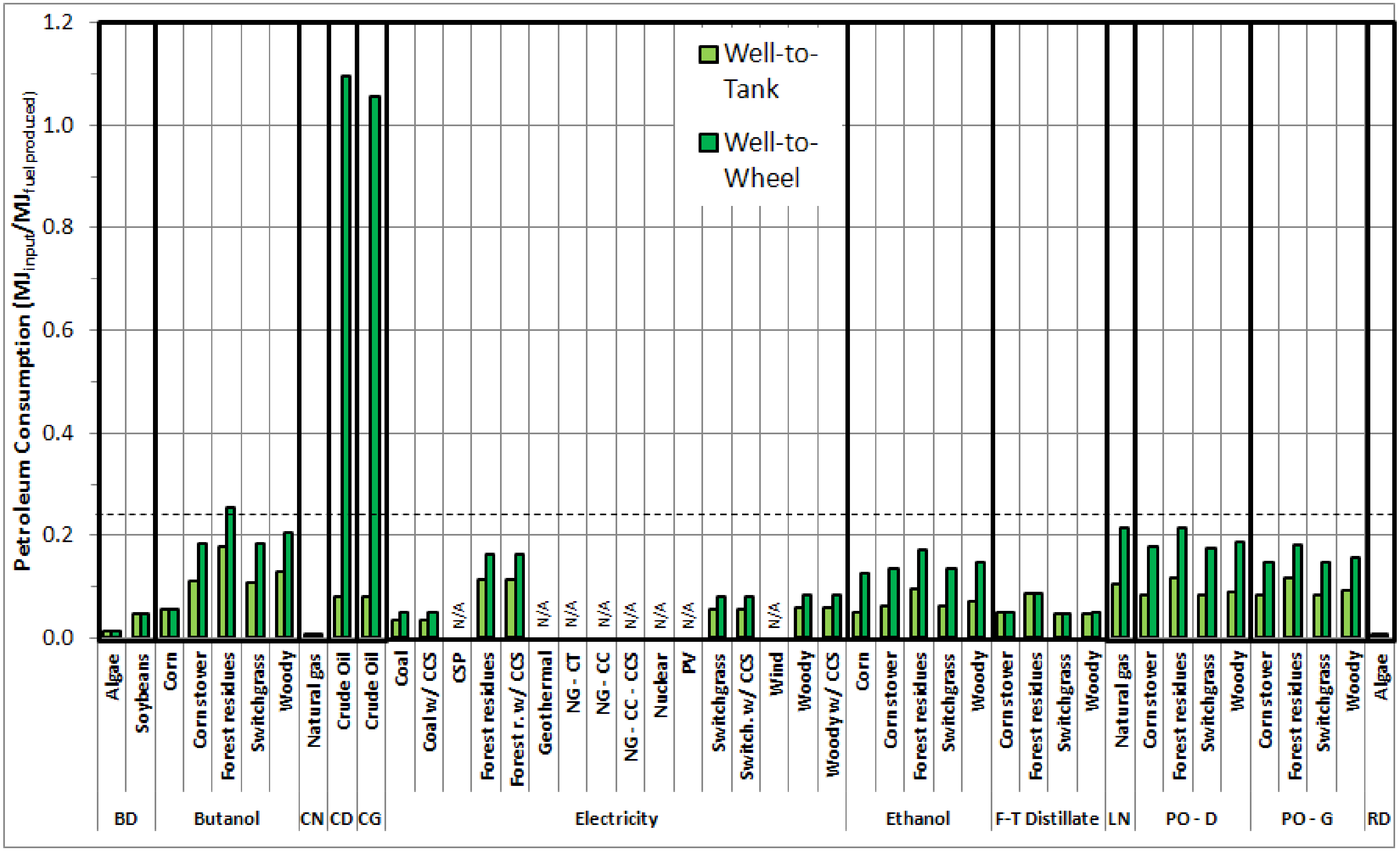


Table K.1. Life Cycle GHG Emissions and Petroleum Consumption Estimates Used in the BASE Model for 2020 and 2050

(WTW and WTT Data are Listed with the Source)

2020

Delivered fuel product type(s)	Primary energy feedstock	Petroleum	GHG Emissions	Petroleum	GHG Emissions	Author/Source	Year of Publication/ Version
Units --->		MJ input/MJ fuel produced	g/MJ fuel produced	MJ input/MJ fuel produced	g/MJ fuel produced	N/A	N/A
Scope--->		WTT	WTT	WTW	WTW	N/A	N/A
BD	Algae	0.01	-42	0.01	36	GHGenius, GREET	3.19a, 1.8d
	Soybeans	0.05	-62	0.05	15	GREET	1.8d
Butanol	Corn	0.06	-17	0.06	54	GREET	1.8d
	Corn stover	0.16	-49	0.23	24	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Forest residues	0.26	-40	0.33	33	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Switchgrass	0.15	-20	0.23	53	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Woody	0.18	-49	0.26	24	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
CN	Natural gas	0.01	15	0.01	72	GREET	1.8d
CD	Crude Oil	0.08	18	1.10	96	GREET	1.8d
CG	Crude Oil	0.08	17	1.05	92	GREET	1.8d
Electricity	Coal	0.03	285	0.05	286	GREET, REF	1.8d, 2011
	Coal w/ CCS	0.03	55	0.05	56	GREET, REF	1.8d, 2011
	CSP	N/A	5	N/A	6	REF	2011
	Forest residues	0.11	25	0.16	25	GREET	1.8d
	Forest r. w/ CCS	0.11	-289	0.16	-289	GREET	1.8d
	Geothermal	N/A	4	N/A	4	REF	2011
	NG - CT	N/A	212	N/A	212	REF	2011
	NG - CC	N/A	134	N/A	134	REF	2011
	NG - CC - CCS	N/A	43	N/A	43	REF	2011
	Nuclear	N/A	4	N/A	4	REF	2011
	PV	N/A	12	N/A	12	REF	2011
	Switchgrass	0.06	39	0.08	39	GREET	1.8d
	Switch. w/ CCS	0.06	-194	0.08	-194	GREET	1.8d
	Wind	N/A	12	N/A	12	REF	2011
	Woody	0.06	20	0.08	20	GREET	1.8d
	Woody w/ CCS	0.06	-228	0.08	-227	GREET	1.8d
Ethanol	Corn	0.05	-23	0.12	50	GREET	1.8d
	Corn stover	0.08	-64	0.15	8	GREET	1.8d
	Forest residues	0.12	-55	0.19	17	GREET	1.8d
	Switchgrass	0.07	-52	0.15	20	GREET	1.8d
	Woody	0.09	-64	0.16	8	GREET	1.8d
F-T Distillate	Corn stover	0.05	-66	0.05	8	GREET	1.8d
	Forest residues	0.09	-65	0.09	9	GREET	1.8d
	Switchgrass	0.05	-57	0.05	16	GREET	1.8d
	Woody	0.05	-67	0.05	6	GREET	1.8d
LN	Natural gas	0.01	16	0.01	74	GREET	1.8d
PO - D	Corn stover	0.11	-52	0.20	23	Hsu, GREET	2011, 1.8d
	Forest residues	0.16	-51	0.26	24	Hsu, GREET	2011, 1.8d
	Switchgrass	0.10	-37	0.20	39	Hsu, GREET	2011, 1.8d
	Woody	0.12	-53	0.22	22	Hsu, GREET	2011, 1.8d
PO - G	Corn stover	0.11	-52	0.17	19	Hsu, GREET	2011, 1.8d
	Forest residues	0.16	-51	0.22	20	Hsu, GREET	2011, 1.8d
	Switchgrass	0.10	-37	0.17	33	Hsu, GREET	2011, 1.8d
	Woody	0.12	-53	0.18	18	Hsu, GREET	2011, 1.8d
RD	Algae	0.01	-14	0.01	60	GHGenius, GREET	3.19a, 1.8d

2050

Delivered fuel product type(s)	Primary energy feedstock	Petroleum	GHG Emissions	Petroleum	GHG Emissions	Author/Source	Year of Publication/ Version
Units --->		MJ input/MJ fuel produced	g/MJ fuel produced	MJ input/MJ fuel produced	g/MJ fuel produced	N/A	N/A
Scope--->		WTT	WTT	WTW	WTW	N/A	N/A
BD	Algae	0.01	-65	0.01	13	GHGenius, GREET	3.19a, 1.8d
	Soybeans	0.05	-64	0.05	13	GREET	1.8d
Butanol	Corn	0.06	-21	0.06	50	GREET	1.8d
	Corn stover	0.11	-49	0.19	23	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Forest residues	0.18	-44	0.26	28	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Switchgrass	0.11	-30	0.18	43	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
	Woody	0.13	-49	0.21	24	GREET, Tao and Aden, Mullins et al.	1.8d, 2001, 2011
CN	Natural gas	0.01	11	0.01	69	GREET	1.8d
CD	Crude Oil	0.08	17	1.10	94	GREET	1.8d
CG	Crude Oil	0.08	15	1.05	90	GREET	1.8d
Electricity	Coal	0.03	284	0.05	284	GREET, REF	1.8d, 2011
	Coal w/ CCS	0.03	55	0.05	56	GREET, REF	1.8d, 2011
	CSP	N/A	5	N/A	6	REF	2011
	Forest residues	0.11	25	0.16	25	Hsu, GREET	2011, 1.8d
	Forest r. w/ CCS	0.11	-289	0.16	-289	GHGenius, GREET	3.19a, 1.8d
	Geothermal	N/A	4	N/A	4	REF	2011
	NG - CT	N/A	212	N/A	212	REF	2011
	NG - CC	N/A	134	N/A	134	REF	2011
	NG - CC - CCS	N/A	43	N/A	43	REF	2011
	Nuclear	N/A	4	N/A	4	REF	2011
	PV	N/A	12	N/A	12	REF	2011
	Switchgrass	0.06	39	0.08	39	GREET	1.8d
	Switch. w/ CCS	0.06	-194	0.08	-194	GREET	1.8d
	Wind	N/A	11	N/A	11	REF	2011
	Woody	0.06	20	0.08	20	GREET	1.8d
	Woody w/ CCS	0.06	-228	0.08	-227	GREET	1.8d
Ethanol	Corn	0.05	-29	0.13	44	GREET	1.8d
	Corn stover	0.06	-58	0.14	15	GREET	1.8d
	Forest residues	0.10	-53	0.17	19	GREET	1.8d
	Switchgrass	0.06	-48	0.14	24	GREET	1.8d
	Woody	0.07	-57	0.15	15	GREET	1.8d
F-T Distillate	Corn stover	0.05	-66	0.05	7	GREET	1.8d
	Forest residues	0.09	-65	0.09	9	GREET	1.8d
	Switchgrass	0.05	-58	0.05	16	GREET	1.8d
	Woody	0.05	-67	0.05	6	GREET	1.8d
LN	Natural gas	0.10	-37	0.22	42	GREET	1.8d
PO - D	Corn stover	0.08	-55	0.18	19	Hsu, GREET	2011, 1.8d
	Forest residues	0.12	-55	0.22	20	Hsu, GREET	2011, 1.8d
	Switchgrass	0.08	-46	0.18	29	Hsu, GREET	2011, 1.8d
	Woody	0.09	-56	0.19	18	Hsu, GREET	2011, 1.8d
PO - G	Corn stover	0.08	-55	0.15	16	Hsu, GREET	2011, 1.8d
	Forest residues	0.12	-55	0.18	17	Hsu, GREET	2011, 1.8d
	Switchgrass	0.08	-46	0.15	24	Hsu, GREET	2011, 1.8d
	Woody	0.09	-56	0.16	15	Hsu, GREET	2011, 1.8d
RD	Algae	0.01	-37	0.01	38	GHGenius, GREET	3.19a, 1.8d

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

Fuel Efficiencies Taken from GREET 1.8d.

Vehicle Type	Fuel Economy
N/A	*MJ_{fuel}/mile*
Internal Combustion Engine	4.34
Compression Ignition Direct Injection	3.62
Flexible Fuel	4.34
Electric	1.32
Fuel Cell	1.78
Dedicated EtOH and BuOH	4.06
Dedicated CNG	4.28
Dedicated LNG	4.28

Figure and Table Acronyms
CNG or CN = compressed natural gas
LNG or LN = liquid natural gas
EtOH = ethanol
BuOH = butanol
PO – D = pyrolysis oil to diesel
PO – G = pyrolysis oil to gasoline
RD = renewable diesel
F-T Diesel = Fischer-Tropsch diesel
CCS = carbon capture and storage
PV = photovoltaic
NG = natural gas
BD = biodiesel
CD = conventional diesel
CG = conventional gasoline
CC = combined cycle

Appendix L: Conventional Fuel Prices and Market Sizes Used for the Low Oil Price Sensitivities

Tables L.1 and L.2 provide the pricing and market size data, respectively, used in the BASE Model low oil price scenario.

Table L.1. Pricing Data Used in the BASE Model Low Oil Price Scenario

Fuel	Year	*Annual Energy Outlook* Value/ Extrapolated Value	*Annual Energy Outlook* Units	BASE Value	BASE Units
Gasoline	2020	17.34	2009\$/10^6Btu	1.68	2005 Chained \$/gal
Gasoline	2050	13.30	2009\$/10^6Btu	1.19	2005 Chained \$/gal
Diesel	2020	15.55	2009\$/10^6Btu	1.67	2005 Chained \$/gal
Diesel	2050	13.08	2009\$/10^6Btu	1.33	2005 Chained \$/gal
Jet Fuel	2020	10.66	2009\$/10^6Btu	1.35	2005 Chained \$/gal
Jet Fuel	2050	13.86	2009\$/10^6Btu	1.78	2005 Chained \$/gal
Bunker Fuel	2020	5.16	2009\$/10^6Btu	0.69	2005 Chained \$/gal
Bunker Fuel	2050	2.55	2009\$/10^6Btu	0.29	2005 Chained \$/gal

Table L.2. Market Size Data Used in the BASE Model Low Oil Price Scenario

Fuel	Year	*Annual Energy Outlook* Value/ Extrapolated Value	*Annual Energy Outlook* Units	BASE Value	BASE Units
Electricity	2020	3,998	Billion kilowatt-hours	3.98 billion	Megawatt-hours
Electricity	2050	5,053	Billion kilowatt-hours	5.05 billion	Megawatt-hours
PHEV - Electricity	2020	9	Billion kilowatt-hours	9 million	Megawatt-hours
PHEV - Electricity	2050	25	Billion kilowatt-hours	25 million	Megawatt-hours
Gasoline	2020	9.69	Million barrels/day	149 billion	Gallons/year
Gasoline	2050	12.72	Million barrels/day	195 billion	Gallons/year
Diesel	2020	3.96	Million barrels/day	60.75 billion	Gallons/year
Diesel	2050	5.26	Million barrels/day	80.69 billion	Gallons/year
Jet Fuel	2020	1.63	Million barrels/day	25.01 billion	Gallons diesel equivalent/year
Jet Fuel	2050	1.85	Million barrels/day	28.38 billion	Gallons diesel equivalent/year
Bunker Fuel	2020	801.26	Trillion Btu	5.35 billion	Gallons diesel equivalent/year
Bunker Fuel	2050	835.85	Trillion Btu	5.6 billion	Gallons diesel equivalent/year

Appendix M: Conversion to 2005$

The TEF project uses 2005 U.S. dollars throughout the project. The GDP chain-type price index, as reported in the *Annual Energy Outlook 2011*,[26] was used to make all conversions to 2005$ by dividing expenses in each year's dollars by the index value for that year (as shown in Table M.1). In the *Annual Energy Outlook*, values were only reported to 2035, so the index was extrapolated to 2050 (as indicated in brackets below).

Table M.1. GDP Chain-Type Price Index Values

Year					2005	2006	2007	2008	2009	2010
Index Value					1	1.033	1.063	1.086	1.096	1.106
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Index Value	1.12	1.133	1.152	1.173	1.197	1.22	1.246	1.272	1.298	1.324
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Index Value	1.35	1.374	1.399	1.424	1.45	1.476	1.504	1.532	1.561	1.589
Year	2031	2032	2033	2034	2035	[2036]	[2037]	[2038]	[2039]	[2040]
Index Value	1.619	1.65	1.682	1.715	1.749	1.781	1.813	1.845	1.877	1.909
Year	[2041]	[2042]	[2043]	[2044]	[2045]	[2046]	[2047]	[2048]	[2049]	[2050]
Index Value	1.941	1.973	2.005	2.037	2.069	2.101	2.133	2.165	2.197	2.229

[26] Table M-1 (Macroeconomic Indicators)

Appendix N: Gasoline Price Elasticity of Demand

N.1. Summary

N.1.1. Gasoline

In the past 5 years, new analysis of gasoline price elasticity of demand (E_{gp}) suggests that it may, in fact, be less elastic than previous widely-used estimates (Havarnek et al. 2011; Hughes et al. 2007). In light of this research, there are valid reasons for the TEF to employ relatively conservative (i.e., inelastic) estimates in the range of -0.10 for short run E_{gp} and -0.30 for long run E_{gp}. This is a change from typical practice, as historical estimates of short-run gasoline E_{gp} have been in the range of -0.15 (as used in *Annual Energy Outlook 2010* and *2011*) to -0.30 [as estimated by Dahl (Dahl 2012), Espey (Espey 1998), and Dahl and Sterner (Dahl and Sterner 1991)].

N.1.2. Diesel

Dahl (2012) estimates short-run diesel price elasticity of demand (E_{dp}) to be lower than that of gasoline; -0.07 compared to -0.30. Internationally, Dahl (2012) finds the median short-run diesel price elasticity to be -0.16.

Short- and long-run estimates are given in Table N.1 and Figure N.1.

N.2. Discussion and Additional Key Points

Both Havranek (Havranek et al. 2011) and Dahl (2012) note that, across international studies, price elasticity estimates are skewed towards higher estimates of elasticity, with results tending to cluster around the medians. Havranek et al. (2011) theorize that this is an artifact of publication bias.

Regarding publication selection bias issues in the literature, Havranek et al. (2011) performed a meta-analysis to investigate the likelihood of publication selection bias on elasticity estimates, and concluded that there is indeed evidence of publication selection bias. In other words, studies yielding inelastic estimates do not get published as often, as such estimates may disagree with theory. It should be noted that publication bias methodology is in itself a subject of academic debate, particularly around whether to benchmark published results against unpublished working papers versus apply mixed-effects meta-regression models that focus on the relationship between reported elasticity versus the reported precision (standard error) of the elasticity estimate. Havranek et al. (2011) use the latter and include a discussion of the methodological debate and their rationale for using modeled results.

Robust research on cross-price elasticity substitution is less abundant than research on gasoline and diesel and own-price elasticity. A literature review by Dahl and Al-Dossary (Al-Dossary 2008) discovered that research cross-price elasticity has been carried out in the most depth for Australia, Indonesia, Italy, the Netherlands, Spain, Turkey, and the United Kingdom. Alves (Alves and De Losso da Silveira Bueno 2003) specified a cross-price elasticity model for Brazilian alcohol-based fuels, and finds a near-zero cross-price elasticity even in the long run, a finding that suggests imperfect substitutability.

Hughes et al. (2007) modeled U.S. elasticity from two periods of rapidly rising gasoline prices (1975–1980 and 2001–2006), and found that demand was far less elastic in the latter period (in the range of -0.034 to -0.077). They theorized that a range of structural and behavioral changes (including land use, increasing disposable income, and more efficient vehicles) had dramatically reduced E_{gp} since 1980. They further critiqued the literature for continuing to use data from the 1980s and 1990s.

Demand for jet fuel is typically estimated to be more inelastic than other fuels. Boshoff (Boshoff 2010) estimated long-run jet fuel E_{jp} in South Africa at -0.10 and a high level of income elasticity of demand (0.9), suggesting that jet fuel demand is determined more by economic growth than by price sensitivity.

Gjolberg found the elasticity of jet fuel in relation to crude oil prices to be near zero (Gjolberg and Johnsen 1999).

N.3. Select Equations

Hughes et al. (2007)

Equation N.1. Basic Price Elasticity of Demand Model

$$\ln G_{jt} = \beta_0 + \beta_1 \ln P_{jt} + \beta_2 \ln Y_{jt} + \varepsilon_j + \varepsilon_{jt} \quad (1)$$

Where G_{jt} is per capita gasoline consumption in gallons in month j and year t, P_{jt} is the real retail price of gasoline in month j and year t, Y_{jt} is real per capita disposable income in month j and year t, ε_j represents unobserved demand factors that vary at the month level and ε_{jt} is a mean zero error term.

Equation N.2. Price Income Interaction Parameter Model

$$\ln G_{jt} = \beta_0 + \beta_1 \ln P_{jt} + \beta_2 \ln Y_{jt} + \beta_3 \ln P_{jt} \ln Y_{jt} + \varepsilon_j + \varepsilon_{jt} \quad (2)$$

Where the interaction term, $\ln P_{jt} \ln Y_{jt}$ captures the extent to which the responsiveness of consumers to price changes increases or decreases as income changes.

Dahl (2012)

Equation N.3. General Form: Static Equation

$$Q_{gt} = \alpha + \beta P_t + \chi Y_t + \delta X_t$$

“Where Q_g is the demand for gasoline, P is the price of gasoline, Y is a measure of income or economics activity, X represents other variables, Greek letters are parameters to be estimated, and t indicates observation t.”

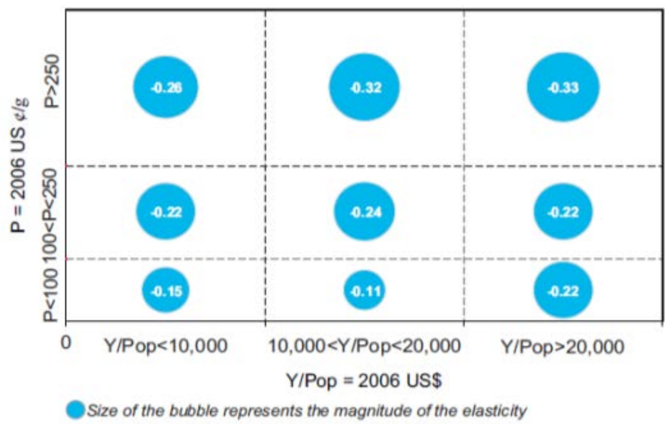
Equation N.4. General Form: Dynamic Equation

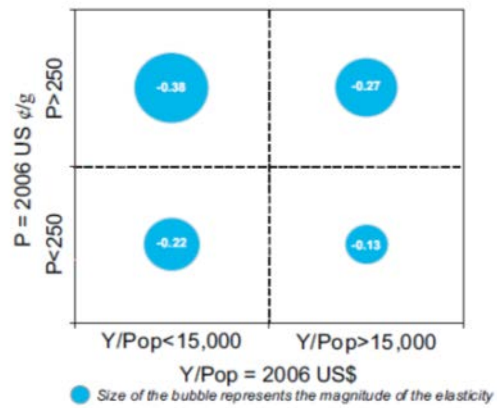
“Dynamic equations typically include non-lagged and lagged variables on the right-hand side of the equation such as

$$Q_{g_t} = \alpha + \beta_0 P_t + \beta_1 P_{t-1} + \chi_0 Y_t + \chi_1 Y_{t-1} + \delta_0 X_t + \delta_1 X_{t-1} + \gamma Q_{g_{t-1}}$$

Dahl also suggests that E_{gp} and E_{dp} grow along with both median income and price.

The figures below show gasoline (left) and diesel (right) price elasticities across various price and income categories.





Alves et al. (2003)

Equation N.5. Cross-Price Substitution Model Equation

$$\ln C_t = \beta_0 + \beta_1 \ln Y_t + \beta_2 \ln P_t + \beta_3 \ln A_t + e_t,$$

Where C_t is yearly gasoline consumption per capita measured in liters; Y_t is yearly real per capita GDP; P_t is yearly real gasoline price; A_t is yearly real alcohol price; e_t is the residual.

Table N.1. Estimates from the Literature

Study/Reference	Product	Method	Short-run Price Elasticity	Long-run Price Elasticity	Long-run Income Elasticity
(Havranek et al. 2011)	Gasoline	Meta-analysis Correcting for Pub Bias	-0.09	-0.31	
(Hughes et al. 2007)	Gasoline	OLS Model for Period 2001–2006	-0.042	---	---
(Dahl 2012)	Gasoline, Diesel	Lit Survey	-0.30		
(*Annual Energy Outlook 2010*, 2011a)	All Non-electric Fuels	Referencing Dahl (1993)	-0.15		
(Dahl and Sterner 1991)	Gasoline	Lit Survey	-0.26	-0.86	1.21
(Espey 1998)	Gasoline	Lit Survey	-0.26	-0.58	0.88
(Graham and Glaister 2004)	Gasoline	Lit Survey	-0.25	-0.77	0.93
(Brons et al. 2008)	Gasoline	Lit Survey	-0.34	-0.84	---
(Dahl 1993)	Oil (Developing Countries)	Lit Survey	-0.07	-0.30	1.32
(Cooper 2003)	Oil (Avg of 23 Countries)	Annual Time-series Regression	-0.05	-0.21	---

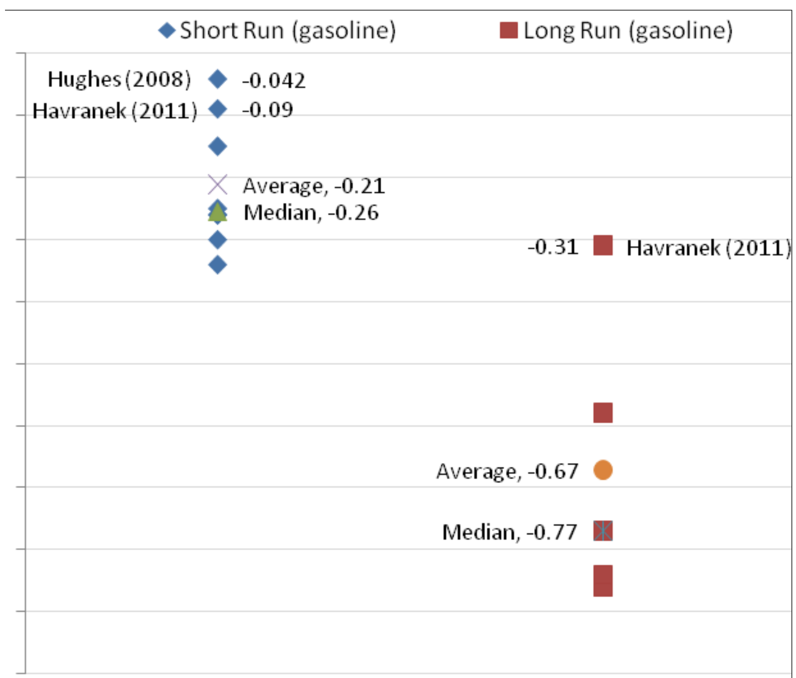


Figure N.1. Summary of gasoline elasticity estimates

(compiled by author)

N.4. Structural and Behavioral Determinants of Elasticity

In the real world, gasoline elasticity is the result of a combination of social and structural factors facing gasoline consumers. The observed inelasticity of demand by Hughes et al. (2008) was attributed non-specifically to a range of factors, which included land-use change (i.e., longer commutes), improved fuel economy via corporate average fuel economy standards, higher disposable income (per capita), increased prevalence of multiple incomes per household, and decreased options for public transit. Several other structural/behavioral factors have been added that may impact both the short- and long-run price elasticity of demand (see Table N.2). If any of these structural or behavioral factors change over the study horizon, elasticity estimates may also change in response.

Table N.2. Likely Gross Impacts of Selected Structural Factors on Gasoline Elasticity

Increase in:	Sprawl	Fuel Economy	Per cap disposable income	Wealth Effects	Multiple incomes/ household	Public Transit	Tele-commuting	Marginal Consumers	Elite Ownership
Impact on short-run E_{pg}	↓	↓	↓	↓	↓	↑	↑	↓	↓

N.5. Notes on Selected Factors

N.5.1 Wealth Effects

In Hughes et al. (2006), it is hypothesized that an increase in disposable income may have driven the dramatically lower inelasticity of demand during 2001–2006. This causal logic is extended to include ‘perceived wealth’, or wealth effects, such as easy credit and asset price appreciation that can yield disposable cash even in the absence of wage growth. The 2001–2006 period was marked by easy credit and home-equity loans that may have allowed many American consumers to be less price sensitive to fuels. The forecast for both sources of ‘perceived wealth’ is dim, and so it may be that demand may return to higher levels of elasticity in the short run.

N.5.2. Marginal Consumers

In some cases, a slight price reduction can cause a disproportionate increase in demand. This effect is most commonly studied in regard to other products, for example, air conditioners, where a 10% reduction in air conditioning unit price in a developing nation can disproportionately increase electricity demand as the price change captures a large number of consumers on the margin. This effect could be observed with regard to prices of advanced vehicles and fuels. In the case of multi-fuel-platform competition, a small price change for a particular type of biofuel or vehicle could non-linearly improve substitutability of biofuel for gasoline, therefore increasing gasoline demand elasticity.

N.5.3. Elite Ownership

Dahl discussed counter-intuitive elasticity estimates in developing countries, where per capita income is low (<$1,000/yr), and yet fuel demand is relatively inelastic. One likely explanation for this finding is that vehicle ownership is concentrated among relatively affluent citizens. Coupled with the prevalence of fuel subsidies in many developing countries, these vehicle owners can afford to be price insensitive. In the scenario in which U.S. vehicle ownership becomes more difficult for medium- and low-income citizens (an unlikely deviation from a long-run historical trend), E_{gp} could actually decrease as the mix of owners becomes more insensitive to price.

N.5.4. Rebound

Small et al. estimated short- and long-run transportation rebound effects to be 4.5% and 22.2%, respectively. In other words, a 10% improvement in fuel efficiency will result in a “take-back,” in the form of a 0.45% increase in vehicle miles traveled. *Annual Energy Outlook 2011* does not assume a take-back due to fuel efficiency: "Only space heating, cooling, and lighting are assumed to be affected by both elasticities and the efficiency rebound effect."

N.5.5. Asymmetry

Dahl (2012) discussed the common assumption that E_{xp} is symmetric, or that fuel price increases and decreases operate equally on consumer demand. In general, Dahl found that models that consider asymmetry are rarely more accurate than those that assume symmetry, although there is some evidence that price movement around historical maxima can have outsized effects. Further research is needed in this area.

References

Al-Dossary, Nasser. 2008. *Global demand for road transport fuels*, Department of Economics and Business, Colorado School of Mines, Golden, CO.

Alfonso, D., C. Perpiñá, A. Pérez-Navarro, E. Peñalvo, C. Vargas, R. Cárdenas. 2009. "Methodology for optimization of distributed biomass resources evaluation, management and final energy use." *Biomass and Bioenergy* no. 33 (8):1070-1079. http://dx.doi.org/10.1016/j.biombioe.2009.04.002

Alternative Fuels & Advanced Vehicles Data Center. U.S. Department of Energy, Energy Efficiency & Renewable Energy. Cited December 23, 2011. www.afdc.energy.gov

Alves, Denisard C. O., Rodrigo De Losso da Silveira Bueno. 2003. "Short-run, long-run and cross elasticities of gasoline demand in Brazil." *Energy Economics* no. 25 (2):191-199. http://dx.doi.org/10.1016/S0140-9883(02)00108-1

Augustine, Chad, Katherine R. Young, Arlene Anderson. 2010. *Updated U.S. Geothermal Supply Curve*. NREL/CP-6A2-47458. Golden, CO: National Renewable Energy Laboratory, 19 pp. http://www.nrel.gov/docs/fy10osti/47458.pdf

Azar, Christian, Kristian Lindgren, Björn A. Andersson. 2003. "Global energy scenarios meeting stringent CO2 constraints—cost-effective fuel choices in the transportation sector." *Energy Policy* no. 31 (10):961-976. http://dx.doi.org/10.1016/S0301-4215(02)00139-8

Beck, R.W. 2010. *Biorefinery Learning Curve Analysis*. Subcontract LCI-9-88660, Deliverable 6.4. Golden, CO: National Renewable Energy Laboratory.

Benson, Geoff, Gary Bullen. 2007. *Break-Even Soybean and Corn Harvesting Yields*. North Carolina State University and North Carolina Agricultural and Technical State University Cooperative Extension, 4 pp. http://www.ces.ncsu.edu/disaster/drought/SoybeanBreakeven.pdf

Berndes, Göran, Monique Hoogwijk, Richard van den Broek. 2003. "The contribution of biomass in the future global energy supply: a review of 17 studies." *Biomass and Bioenergy* no. 25 (1):1-28. http://dx.doi.org/10.1016/S0961-9534(02)00185-X

Biomass Logistics Model V6.45. Idaho National Laboratory, Idaho Falls, ID.

Black & Veatch. 2008. *Renewable Energy Options*. 13 pp. http://www.bv.com/downloads/Resources/Reports/RenewableEnergyPletka2008.pdf

Boshoff, Willem H. 2010. *Petrol, diesel fuel and jet fuel demand in South Africa: 1998-2009*. Matieland, South Africa: Stellenbosch University, Department of Economics, 19 pp. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1661021

Brons, Martijn, Peter Nijkamp, Eric Pels, Piet Rietveld. 2008. "A meta-analysis of the price elasticity of gasoline demand. A SUR approach." *Energy Economics* no. 30 (5):2105-2122. http://dx.doi.org/10.1016/j.eneco.2007.08.004

Campbell, J. E., E. Block. 2010. "Land-Use and Alternative Bioenergy Pathways for Waste Biomass." *Environmental Science & Technology* no. 44 (22):8665-8669. http://dx.doi.org/10.1021/es100681g

Campbell, J. E., D. B. Lobell, C. B. Field. 2009. "Greater Transportation Energy and GHG Offsets from Bioelectricity Than Ethanol." *Science* no. 324 (5930):1055-1057. http://dx.doi.org/10.1126/science.1168885

Clarke, L., M. Wise, J. Edmonds, P. Kyle, K. Calvin, S. Kim, S. Smith. 2008. *CO_2 Emissions Mitigation and Technological Advance: An Updated Analysis of Advanced Technology Scenarios*. PNNL-18075. Richland, WA: Pacific Northwest National Laboratory. http://www.pnl.gov/science/pdf/PNNL18075.pdf and http://www.pnl.gov/science/pdf/PNNL18075Appendices.pdf

Cooper, John C. B. 2003. "Price elasticity of demand for crude oil: estimates for 23 countries." *OPEC Review* no. 27 (1):1-8. http://dx.doi.org/10.1111/1468-0076.00121

Cowie, Annette L., W. David Gardner. 2007. "Competition for the biomass resource: Greenhouse impacts and implications for renewable energy incentive schemes." *Biomass and Bioenergy* no. 31 (9):601-607. http://dx.doi.org/10.1016/j.biombioe.2007.06.019

Dahl, Carol. 1993. "A survey of oil demand elasticities for developing countries." *OPEC Review* no. 17 (4):399-420. http://dx.doi.org/10.1111/j.1468-0076.1993.tb00484.x

Dahl, Carol A. 2012. "Measuring global gasoline and diesel price and income elasticities." *Energy Policy* no. 41 (0):2-13. http://dx.doi.org/10.1016/j.enpol.2010.11.055

Dahl, Carol, Thomas Sterner. 1991. "Analysing gasoline demand elasticities: a survey." *Energy Economics* no. 13 (3):203-210. http://dx.doi.org/10.1016/0140-9883(91)90021-Q

Dai, Aiguo. 2011. "Drought under global warming: a review." *Wiley Interdisciplinary Reviews: Climate Change* no. 2 (1):45-65. http://dx.doi.org/10.1002/wcc.81

Davis, Ryan, Andy Aden, Philip T. Pienkos. 2011. "Techno-economic analysis of autotrophic microalgae for fuel production." *Applied Energy* no. 88 (10):3524-3531. http://dx.doi.org/10.1016/j.apenergy.2011.04.018

Davis, Ryan, Eric Tan. 2011. *Comparison of Biomass Pathways for Vehicle Use: Milestone Complettion Report (internal report)*. Golden, CO.: National Renewable Energy Laboratory.

Espey, Molly. 1998. "Gasoline demand revisited: an international meta-analysis of elasticities." *Energy Economics* no. 20 (3):273-295. http://dx.doi.org/10.1016/S0140-9883(97)00013-3

Food and Agricultural Policy Research Institute. 2010. *FAPRI 2010: U.S. and World Agricultural Outlook*. FAPRI Staff Report 10-FSR 1. Ames, Iowa, 418 pp. http://www.fapri.iastate.edu/outlook/2010/text/Outlook_2010.pdf

Friley. 2010. Personal communications regarding Market Allocation Model (MARKAL).

Gielen, D. J., J. Fujino, S. Hashimoto, Y. Moriguchi. 2002. "Biomass strategies for climate policies?" *Climate Policy* no. 2 (4):319-333. http://dx.doi.org/10.3763/cpol.2002.0237

Gielen, Dolf, Junichi Fujino, Seiji Hashimoto, Yuichi Moriguchi. 2003. "Modeling of global biomass policies." *Biomass and Bioenergy* no. 25 (2):177-195. http://dx.doi.org/10.1016/S0961-9534(02)00188-5

Gjolberg, Ole, Thore Johnsen. 1999. "Risk management in the oil industry: can information on long-run equilibrium prices be utilized?" *Energy Economics* no. 21 (6):517-527. http://dx.doi.org/10.1016/S0140-9883(99)00023-7

GPRA Modernization Act of 2010. 2011. In *Public Law 111–352*, edited by Senate and House of Representatives of the United States of America. Washington, DC: United States Government Printing Office.

Graham, Daniel J., Stephen Glaister. 2004. "Road Traffic Demand Elasticity Estimates: A Review." *Transport Reviews* no. 24 (3):261-274. http://dx.doi.org/10.1080/0144164032000101193

Grahn, Maria, Christian Azar, Kristian Lindgren, Göran Berndes, Dolf Gielen. 2007. "Biomass for heat or as transportation fuel? A comparison between two model-based studies." *Biomass and Bioenergy* no. 31 (11-12):747-758. http://dx.doi.org/10.1016/j.biombioe.2007.05.001

GREET Model: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation. Argonne National Laboratory. Cited December 20, 2011. http://greet.es.anl.gov/

Havranek, Thomas, Zuzana Irsova, Karel Janda. 2011. *Demand for Gasoline is More Price Inelastic than Commonly Thought*. Prgaue, Czech Republic: Charles University. http://ies.fsv.cuni.cz/default/file/download/id/16161

Hsu, David D. 2011. *Life Cycle Assessment of Gasoline and Diesel Produced via Fast Pyrolysis and Hydroprocessing*. Golden, CO: National Renewable Energy Laboratory, 28 pp. http://www.nrel.gov/docs/fy11osti/49341.pdf

Hughes, Jonathan, Christopher R. Knittel, Dan Sperling. 2007. *Evidence of a Shift in the Short-Run Price Elasticity of Gasoline Demand*. Berkeley, CA.: Center for the Study of Energy Markets, University of California Energy Institute, UC Berkeley. http://escholarship.org/uc/item/86m171mn

Humbird, D., R. Davis, L. Tao, C. Kinchin, D. Hsu, A. Aden, P. Schoen, J. Lukas, B. Olthof, M. Worley, D. Sexton, D. Dudgeon. 2011. *Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol: Dilute-Acid Pretreatment and Enzymatic Hydrolysis of Corn Stover*. Golden, CO: National Renewable Energy Laboratory, 147 pp. http://www.nrel.gov/docs/fy11osti/47764.pdf

Hydrogen Analysis Resource Center. U.S. Department of Energy. Cited December 23, 2011. http://hydrogen.pnl.gov/cocoon/morf/hydrogen

Ignaciuk, A., F. Vöhringer, A. Ruijs, E. C. van Ierland. 2006. "Competition between biomass and food production in the presence of energy policies: a partial equilibrium analysis." *Energy Policy* no. 34 (10):1127-1138. http://dx.doi.org/10.1016/j.enpol.2004.09.010

Institute for Energy and Environmental Research (IFEU). 2007. *Biomass as a Resource for the Chemical Industry: Key findings of an IFEU study and conclusions of the VCI*. Heidelberg, Germany, 8 pp. http://www.ifeu.de/landwirtschaft/pdf/VCI_IFEU_Biomass_Chemical_Industry.pdf

Iowa State University. *Ag Decision Maker*. Iowa State University: Extension and Outreach. Cited June 11, 2012. http://www.extension.iastate.edu/agdm/crops/html/a2-11.html

Jones, S.B., C. Valkenburh, C.W. Walton, D.C. Elliott, J.E. Holladay, D.J. Stevens, C. Kinchin, S. Czernik. 2009. *Production of Gasoline and Diesel from Biomass via Fast Pyrolysis, Hydrotreating and Hydrocracking: A Design Case*. Richland, WA: Pacific Northwest National Laboratory, 76 pp. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18284rev1.pdf

Kalt, Gerald. 2011. *An assessment of the implications, costs and benefits of bioenergy use based on techno-economic approaches*.

Kalt, Gerald, Lukas Kranzl, Reinhard Haas. 2010. “Long-term strategies for an efficient use of domestic biomass resources in Austria.” *Biomass and Bioenergy* no. 34 (4):449-466. http://dx.doi.org/10.1016/j.biombioe.2009.12.009

Khanna, Madhu, Xiaoguang Chen, Haixiao Huang, Hayri Önal. 2010. Supply of Cellulosic Biofuel Feedstocks and Regional Production Patterns. Paper read at Agricultural & Applied Economics Association’s 2010 AAEA, CAES & WAEA Joint Annual Meeting, at Denver, CO. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1695811

Laser, Mark, Eric Larson, Bruce Dale, Michael Wang, Nathanael Greene, Lee R. Lynd. 2009. “Comparative analysis of efficiency, environmental impact, and process economics for mature biomass refining scenarios.” *Biofuels, Bioproducts and Biorefining* no. 3 (2):247-270. http://dx.doi.org/10.1002/bbb.136

Luckow, P., M.A. Wise, J.J. Dooley, S.H. Kim. 2010. *Biomass Energy for Transport and Electricity: Large Scale Utilization Under Low CO2 Concentration Scenarios*. PNNL-19124. Richland, WA.: Pacific Northwest National Laboratory, 28 pp. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19124.pdf

Mai, T., R. Wiser, D. Sandor, G. Brinkman, G. Heath, P. Denholm, D.J. Hostick, N. Darghouth, A. Schlosser, K. Strzepek. 2012. *Renewable Electricity Futures Study: Exploration of High-Penetration Renewable Electricity Futures* NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory, 280 pp. http://www.nrel.gov/docs/fy12osti/52409-1.pdf

Morrow, William R., W. Michael Griffin, H. Scott Matthews. 2006. “Modeling Switchgrass Derived Cellulosic Ethanol Distribution in the United States.” *Environmental Science & Technology* no. 40 (9):2877-2886. http://dx.doi.org/10.1021/es048296m

Morrow, William R., III, Peter Balash. 2008. *Biomass Allocation Model: Comparing Alternative Uses of Scarce Biomass Energy Resources Through Estimations of Future Biomass Use for Liquid Fuels and Electricity*. DOE/NETL-2008/1302. National Energy Technology Laboratory, 96 pp.

http://www.netl.doe.gov/energy-analyses/pubs/Biomass%20Allocation%20Model%20Report%20R2%20%2810-01-08%29.pdf

Mullins, Kimberley A., W. Michael Griffin, H. Scott Matthews. 2010. "Policy Implications of Uncertainty in Modeled Life-Cycle Greenhouse Gas Emissions of Biofuels⊥." *Environmental Science & Technology* no. 45 (1):132-138. http://dx.doi.org/10.1021/es1024993

Newes, Emily, Brian Bush, Daniel Inman, Yolanda Lin, Trieu Mai, Andrew Martinez, David Mulcahy, Walter Short, Travis Simpkins, Caroline Uriarte, Corey Peck. 2012. *Biomass Resource Allocation Among Competing End Uses*. NREL/TP-6A20-54217. Golden, CO: National Renewable Energy Laboratory, 66 pp. http://www.nrel.gov/docs/fy12osti/54217.pdf

Newes, Emily, Daniel Inman, Brian Bush. 2011. "Understanding the Developing Cellulosic Biofuels Industry through Dynamic Modeling" In *Economic Effects of Biofuel Production*, edited by Marco Aurélio dos Santos Bernardes. InTechOpen.

NREL. *Biomass Scenario Model*. National Renewable Energy Laboratory, DOE Office of the Biomass Program 2011. Cited December 14, 2011. https://bsm.nrel.gov/

Ohlrogge, John, Doug Allen, Bill Berguson, Dean DellaPenna, Yair Shachar-Hill, Sten Stymne. 2009. "Driving on Biomass." *Science* no. 324 (5930):1019-1020. http://www.sciencemag.org/content/324/5930/1019.short

OpenEI. *MARKet ALlocation (MARKAL)*. Department of Energy. Cited September 14, 2012. http://en.openei.org/wiki/MARKet_ALlocation_(MARKAL)

Perlack, Bob, Matt Langholtz, Laurence Eaton, Craig Brandt, Anthony Turhollow, Robin Graham Webb, Mark Downing. 2011. *Supply Forecast & Analysis: 2011 Feedstocks Review*. Oak Ridge, TN: Oak Ridge National Laboratory, 37 pp. http://www.ornl.gov/sci/bioenergy/presentations/Supply%20Forecast%20&%20Analysis_April%202011.pdf

Reinbott, David. *2012 Southeast Missouri Crop Budgets*. University of Missouri Extension, November 24, 2011 2012. Cited December 23, 2011. http://extension.missouri.edu/seregion/Crop_Budgets_PDF.htm

(S&T)[2] Consultants. 2004. *GHGenius: A Model for Lifecycle Assessment of Transportation Fuels*. Natural Resources Canada. http://www.ghgenius.ca/

Short, W., P. Sullivan, T. Mai, M. Mowers, C. Uriarte, N. Blair, D. Heimiller, A. Martinez. 2011. *Regional Energy Deployment System (ReEDS)*. NREL/TP-6A20-46534. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy12osti/46534.pdf

Short, Walter, Daniel J. Packey, Thomas Holt. 1995. *A Manual for the Economic Evaluation of Energy Efficiency and Renewable Energy Technologies*. NREL/TP-462-5173. Golden, CO: National Renewable Energy Laboratory, 120 pp. http://www.nrel.gov/docs/legosti/old/5173.pdf

Stochastic Energy Deployment Systems (SEDS). National Renewable Energy Laboratory. Cited December 23, 2011. http://seds.nrel.gov

Sun, J. C., P. X. Li, L. N. Hou. 2011. "Game Equilibrium of Agricultural Biomass Material Competition - Its Assumptions, Conditions and Probability." *Energy Procedia* no. 5:1163-1171. http://dx.doi.org/10.1016/j.egypro.2011.03.204

Swanson, Ryan M., Alexandru Platon, Justinus A. Satrio, Robert C. Brown. 2010. "Techno-economic analysis of biomass-to-liquids production based on gasification." *Fuel* no. 89, Supplement 1:S11-S19. http://dx.doi.org/10.1016/j.fuel.2010.07.027

Tao, Ling, Andy Aden. 2009. "The economics of current and future biofuels." *In Vitro Cellular & Developmental Biology – Plant* no. 45 (3):199-217. http://dx.doi.org/10.1007/s11627-009-9216-8

———. 2011. *Technoeconomic analysis of corn butanol and corn stover butanol (forthcoming)*. Golden, CO: National Renewable Energy Laboratory.

Trink, Thomas, Christoph Schmid, Thomas Schinko, Karl W. Steininger, Thomas Loibnegger, Claudia Kettner, Alexandra Pack, Christoph Töglhofer. 2010. "Regional economic impacts of biomass based energy service use: A comparison across crops and technologies for East Styria, Austria." *Energy Policy* no. 38 (10):5912-5926. http://dx.doi.org/10.1016/j.enpol.2010.05.045

U.S. Department of Energy (DOE). 2011. *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*. ORNL/TM-2011/224. Washington DC, 228 pp. http://www1.eere.energy.gov/biomass/pdfs/billion_ton_update.pdf

U.S. Energy Information Administration. *Archive-Alternative Transportation Fuels (ATF) and Alternative Fueled Vehicles (AFV)*. U.S. Energy Information Administration (DOE). Cited October 4, 2012. http://www.eia.gov/renewable/afv/archive/index.cfm

———. *Renewable Energy Consumption by Sector and Source, Reference Case*. U.S. Energy Information Administration (U.S. DOE). Cited October 4, 2012. http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2011&subject=0-AEO2011&table=24-AEO2011&region=0-0&cases=ref2011-d020911a

———. 2004. *Renewable Energy Trends 2003: With Preliminary Data for 2003*. Washington, DC: U.S. Energy Information Administration, 39 pp. http://www.eia.gov/cneaf/solar.renewables/page/_rea_data/trends.pdf

———. 2010a. *Monthly Energy Review-May 2010*. Washington DC, 210 pp. http://www.eia.gov/FTPROOT/multifuel/mer/00351005.pdf

———. 2010b. *Renewable Energy Consumption and Electricity Preliminary Statisitcs 2009*. Washington, DC, 18 pp. http://www.eia.gov/cneaf/alternate/page/renew_energy_consump/rea_prereport.html

———. 2010c. *Renewable Energy Trends in Consumption and Electricity 2008*. Washington, DC, 49 pp. http://www.eia.gov/cneaf/solar.renewables/page/trends/trends.pdf

———. 2011a. *Annual Energy Outlook 2011 with Projections to 2035*. Washington, DC, 246 pp. http://www.eia.gov/forecasts/aeo/pdf/0383%282011%29.pdf

———. 2011b. *Petroleum Marketing Monthly*. DOE/EIA-0380(2011/08). Washington, DC, 133 pp. http://www.eia.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_monthly/historical/2011/2011_08/pdf/pmmall.pdf

U.S. Government Accountability Office. 2007. *Biofuels: DOE Lacks a Strategic Approach to Coordinate Increasing Production with Infrastructure Development and Vehicle Needs*. GAO-07-713. Washington, DC, 56 pp. http://www.gao.gov/assets/270/261764.pdf

U.S. Soybean Export Council. *Statistical Conversions*. U.S. Soybean Export Council. Cited December 23, 2011. http://ussec.org/resources/conversions.html

Vink, Erwin T. H., Karl R. Rábago, David A. Glassner, Bob Springs, Ryan P. O'Connor, Jeff Kolstad, Patrick R. Gruber. 2004. "The Sustainability of NatureWorks™ Polylactide Polymers and Ingeo™ Polylactide Fibers: an Update of the Future." *Macromolecular Bioscience* no. 4 (6):551-564. http://dx.doi.org/10.1002/mabi.200400023

Wahlund, Bertil, Jinyue Yan, Mats Westermark. 2004. "Increasing biomass utilisation in energy systems: A comparative study of CO2 reduction and cost for different bioenergy processing options." *Biomass and Bioenergy* no. 26 (6):531-544. http://dx.doi.org/10.1016/j.biombioe.2003.09.003

Walker, Thomas, Peter Cardellichio, Andrea Colnes, John Gunn, Brian Kittler, Bob Perschel, Christopher Recchia, David Saah. 2010. *Biomass Sustainability and Carbon Policy Study (chapter 2)*. NCI-2010-03. Boston, MA: Commonwealth of Massachusetts, Department of Energy Resources, 12 pp. http://www.mass.gov/eea/docs/doer/renewables/biomass/manomet-biomass-report-chapter2.pdf

What We Pay for in a Gallon of Regular Gasoline. 2011. U.S. Energy Information Administration (DOE) 20112011. http://www.eia.gov/todayinenergy/detail.cfm?id=470

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Argonne
NATIONAL LABORATORY

U.S. DEPARTMENT OF
ENERGY | Energy Efficiency & Renewable Energy

Prepared by NREL for the U.S. Department of Energy

The Transportation Energy Futures Series is a joint project of the National Renewable Energy Laboratory (NREL) and Argonne National Laboratory, national laboratories of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy.

DOE/GO-102013-3707 • March 2013

eere.energy.gov/analysis/transportationenergyfutures

Printed with a renewable-source ink on paper containing at least 50% wastepaper, including 10% post consumer waste.