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Energy and Economic Impacts of Implementing Both a 25-Percent Renewable Portfolio Standard and a 25-Percent Renewable Fuel Standard by 2025

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Preface

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Background

This report responds to a request by Senator James Inhofe for analysis of a "25-by-25" proposal that combines a requirement that a 25-percent share of electricity sales be produced from renewable sources by 2025 with a requirement that a 25-percent share of liquid motor transportation fuel sales also be derived from renewable sources by 2025. The electricity requirement is implemented as a renewable portfolio standard (RPS), while the motor fuel standard is implemented as a renewable fuel standard (RFS).

The RPS establishes a market for renewable energy credits, which will be created by the generation of electricity from qualified renewable generators (e.g., wind, geothermal, biomass, and solar). Electricity retailers must hold RPS credits in proportion to the amount of electricity they sell. Electricity providers can generate their own renewable electricity or trade renewable electricity credits to assure compliance. Similarly, the RFS establishes a market for renewable fuel credits, based on the amount of ethanol or other biofuels sold for motor transportation. Transportation fuel providers must hold RFS credits in proportion to the amount of motor transportation fuels they sell.

This study compares a Policy Case incorporating the 25-by-25 proposal to an updated version of the Reference Case from the Energy Information Administration's (EIA's) *Annual Energy Outlook 2007* (*AEO2007*).[1] Revisions to the Reference Case for this analysis included: expiration of existing ethanol tax credits and tariffs as currently scheduled by law; updates to supply curves for domestic biomass and corn resources; inclusion of offshore wind technology; and updates of the potential for ethanol imports from Brazil.

Analysis Issues

All long-term projections contain considerable uncertainty. This analysis suggests that, to comply with the twin 25-by-25 mandates, it will be necessary for electricity and motor fuel producers to dramatically increase their use of technologies that play a relatively small role in today's energy markets. For example, the amount of qualifying renewable generation needed to comply with the RPS would require almost a 13-fold increase in nonhydropower renewable generation from 2005 levels by 2025. Similarly, the amount of ethanol and biodiesel needed to comply with the RFS would require more than a 12-fold increase from 2005 levels.

Big changes in the energy system, especially when implemented quickly, come with numerous uncertainties, the impacts of which may not be fully captured in this study. For example, compliance with the twin 25-by-25 mandates would require successful development and rapid deployment of new technologies, such as biomass gasification power plants and cellulosic ethanol plants, that currently are not commercially available. Policy case results are very sensitive to assumptions made regarding the cost and

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[1]Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0838(2007) (Washington, DC, February 2002), web site http://www.eia.doe.gov/oiaf/aeo/index.html.

availability of key technologies. Even current technologies, such as wind power, engender significant uncertainties. Once the most economical wind resources are utilized, less attractive resources would have to be developed, with costs that are not well understood.

While a strong push for renewable energy technologies could lead to significant reductions in their costs through breakthroughs or learning, it is also possible that costly hurdles—such as resistance to the siting of new plants, higher than expected transmission interconnection costs, and fuel supply limits—could arise, limiting the development and deployment of renewable energy technologies, and making the proposed mandates much more disruptive and possibly unattainable.

The large increases in bioenergy resources, including corn and other energy crops, that would be needed to comply with the 25-percent RPS and RFS requirements could have significant impacts on agricultural markets and put upward pressure on food and feed prices worldwide. While very rapid improvements in crop yields could limit such pressures, there is considerable uncertainty about the potential for and timing of such improvements. The RFS would also require rapid market penetration of Flex Fuel Vehicles (FFVs) and development of the infrastructure needed to deliver E85 and biodiesel to consumers. As requested, this study assumes that the Senate Bill 23 (S.23) provisions requiring the sale of FFVs and installation of E85 pumps would be put in place.

In addition to technological uncertainties, the Policy Case implies structural changes in the U.S. economy that are not readily apparent from the aggregate impacts on gross domestic product (GDP) or energy prices. Implementation of the proposed RFS policy is likely to involve a major realignment of current capital investment plans and strategies for refiners, automotive manufacturers, and others. For example, substantial capital investment would be needed to put the E85 infrastructure in place to meet the requirements under the RFS policy.

The results of this analysis also suggest that the 25-percent requirement for renewable motor fuel use would significantly increase the use of corn in ethanol production, leading to sharply higher corn prices, substantial changes in domestic feed practices, and large cuts in or elimination of corn exports. The uncertainties inherent in implementing this policy suggest that, while not impossible, it would be very challenging and carry substantial risk.

Key Results

Electricity Sector Impacts

The RPS causes a dramatic shift away from coal and natural gas to renewable fuels, particularly biomass and wind.

- Coal-fired electricity generation in the Policy Case is 938 billion kilowatthours (28 percent) lower in 2030 than in the Reference Case. Natural-gas-fired generation is 99 billion kilowatthours (11 percent) lower in 2030. Generation from nuclear power is 80 billion kilowatthours (9 percent) lower in 2030.

- In the Policy Case, biomass generation is 495 billion kilowatthours (363 percent) higher in 2030 than in the Reference Case, while wind generation is 424 billion kilowatthours (824 percent) higher. To reach the generation levels in the Policy Case, biomass and wind capacity grow to more than 10 times their current levels.

- To comply with a 25-percent RPS, almost 70 percent of the generating capacity added from 2005 to 2025 would have to be renewable technologies—amounting to more than a 10-fold increase in nonhydroelectric renewable capacity over this period.

The RPS credit price and the growing dependence on higher-cost renewables lead to higher electricity prices and higher consumer electricity bills, particularly in 2025 and beyond.

- Average retail electricity prices are 6.2 percent (0.5 cents per kilowatthour in 2005 dollars[2]) higher in the Policy Case than in the Reference Case in 2030. The RPS credit price generally increases through 2025, when the maximum required share for renewable generation is initially imposed. From 2025 to 2030, the RPS credit price is projected to vary between 3.8 and 4.8 cents per kilowatthour.

- In the Policy Case, annual consumer expenditures on electricity are very close to those in the Reference Case through 2022, as the reduction in fuel prices caused by lower fossil fuel use for electric power generation outweighs the increased capital costs of new renewable generation capacity. After 2023, the net capital investment costs of meeting the RPS and the higher renewable fuel costs outweigh the changes in fossil fuel prices, and electricity expenditures are higher than in the Reference Case. Consumer expenditures for electricity in the Policy Case are $16 billion (3.9 percent) higher in 2030; however, the higher electricity bills are partially offset by lower natural gas bills.

- Cumulative (undiscounted) expenditures for electricity for the period 2009-2030 are about $65 billion (about 0.8 percent) higher than in the Reference Case, while cumulative discounted expenditures are $15 billion (0.4 percent) higher.

Liquid Fuels and Transportation Sector Impacts

The RFS mandate results in dramatic increases in biofuels consumption and reduced consumption of petroleum-based fuels.

- To meet the RFS requirements in the Policy Case, ethanol production increases more than 4-fold over production in the Reference Case in 2025. In the Policy Case, about 30 billion gallons of ethanol is sold in 2020, 61 billion gallons in 2025, and 66 billion gallons in 2030. In the Reference Case, only 11 billion gallons of ethanol is sold in 2020, 13 billion gallons in 2025, and 16 billion gallons in 2030.

- In 2025, the E85 share of the gasoline pool is over 30 percent in the Policy case, compared to less than 1 percent in the Reference Case.[3] Such a shift would require

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[2] All energy price and expenditure values in this report are in 2005 dollars.
[3] E85 contains approximately 75 percent ethanol and 25 percent gasoline. E85 consumption in 2025 is 4.3 million barrels per day, and the total gasoline pool is 12.87 million barrels per day.

massive investment to ensure that vehicles and delivery and refueling infrastructure are in place to meet the needs of the market.

- Corn-based ethanol production in the Policy Case increases to about 25.5 billion gallons in 2025 and 2030, almost triple the 9.0 billion gallons produced from corn in the Reference Case in 2025. In the Reference Case, corn-based ethanol production increases to nearly 12 billion gallons in 2030.

- Cellulosic ethanol technology is assumed to become commercially available in 2010, but the relatively high capital costs of cellulosic ethanol plants is initially a significant barrier to its adoption. After 2015, with RFS credit prices and corn prices rising in the Policy Case, cellulosic ethanol becomes more economical, and production grows to about 8 billion gallons in 2020, 28 billion gallons in 2025, and more than 31 billion gallons in 2030.

- Increased ethanol imports meet part of the high biofuel requirement of the proposed RFS policy. In the Policy Case, ethanol imports grow to 8 billion gallons (137 percent more than in the Reference Case) in 2025 and 9 billion gallons (158 percent more than in the Reference Case) in 2030.

- Consumption of petroleum products[4] is significantly reduced. Relative to the Reference Case, nonrenewable liquid fuel use is about 2.3 quadrillion Btu (5 percent) lower in 2020, 5.3 quadrillion Btu (11 percent) lower in 2025, and 6.0 quadrillion Btu (12 percent) lower in 2030. The RFS mandate increases transportation energy prices and consumer expenditures for transportation fuels.

- The projected retail price of gasoline in the Policy Case increases by about 10 cents per gallon (5 percent) in 2020, 28 cents (13 percent) in 2025, and 24 cents (11 percent) in 2030 relative to Reference Case prices. Diesel fuel price increases are somewhat greater than those for gasoline, because production of biodiesel is not large enough to affect the price of diesel imports.

- Consumer expenditures on liquid transportation fuels increase by $28 billion (about 5.4 percent) in 2020 and about $50 billion (8 percent) in 2030 in the Policy Case relative to the Reference Case.

- Cumulative *undiscounted* transportation energy expenditures by consumers from 2009 to 2030 are about $562 billion higher in the Policy Case than in the Reference Case. Cumulative *discounted* expenditures over the same period are $193 billion higher in the Policy Case than in the Reference Case.

- The RFS credit price, which reflects the payment above market value that is required to bring the marginal gallon of renewable fuel to market in the Policy Case, is $2.18 per gallon in 2025 and falls to $2.02 per gallon in 2030.

[4] Excludes consumption of ethanol and biodiesel.

Higher prices contribute to a reduction in transportation demand for liquid motor fuels on an energy basis.

- Total demand for light-duty vehicle travel is 1.6 percent (62 billion vehicle miles) lower in 2025 and 2.2 percent (93 billion vehicle miles) lower in 2030 in the Policy Case than in the Reference Case.

- In the last decade of the projection period, higher fuel prices in the Policy Case cause a shift in consumer preference from light trucks to cars. By 2030, the shift more than makes up for the drop in fuel economy resulting from lower sales of hybrid and diesel vehicles.

- On an energy basis, transportation liquids consumption in 2030 decreases by 2.5 percent, from 38.2 quadrillion Btu in the Reference Case to 37.2 quadrillion Btu in the Policy Case.

Other Energy Impacts

- Increasing the use of renewable motor fuels leads to higher overall consumption of primary energy, in part because of the significant use of energy in the conversion from biomass to ethanol.

- Projected primary energy use from coal, oil, natural gas, and nuclear fuel is reduced substantially. Compared to the Reference Case, total nonrenewable primary energy use is nearly 4.8 percent lower in 2020, 7.7 percent lower in 2025, and 8.6 percent lower in 2030 in the Policy Case.

    - The reduction in coal, nuclear fuel, and natural gas energy use is primarily driven by the RPS. In the Policy Case, coal use is 3.1 quadrillion Btu (11 percent) lower in 2020, 6.1 quadrillion Btu (20 percent) lower in 2025, and 7.8 quadrillion Btu (23 percent) lower in 2030 than in the Reference Case. Between 2020 and 2030, the corresponding decrease in natural gas consumption ranges from 1.8 percent to 5.2 percent. The reductions in nuclear power are smaller than 10 percent in all years.

    - The reduction in petroleum consumption and the increase in biofuels consumption of ethanol and biodiesel are driven by the RFS. Relative to the Reference Case, petroleum consumption in the Policy Case is 11.4-percent (2.8 million barrels per day) lower in 2025 and 12.1-percent (3.1 million barrels per day) lower in 2030.

- The demand for net imports of crude oil and petroleum products, is reduced by approximately 0.8 million barrels per day in 2020, 2.1 million barrels per day in 2025, and 2.4 million barrels per day in 2030. Domestic crude oil production is minimally affected in the Policy Case, but refinery gain is reduced due to reduced refining activity and natural gas liquids production falls with the reduction in natural gas production resulting primarily from the RPS.

- On the basis of energy content, the RFS credit price in the Policy Case is significantly higher ($25.80 per million Btu in 2025 and $23.90 per million Btu in 2030) than the

RPS credit price for the electricity sector ($11.20 per million Btu in 2025 and $14.10 per million Btu in 2030). In other words, the difference in cost between renewable transportation fuels (in this case, ethanol) and fuels that are used for motor fuel transportation in the Reference Case is larger than the corresponding cost difference in electricity generation costs.

Greenhouse Gas Emissions Impacts

- Total U.S. energy-related carbon dioxide emissions in the Policy Case are 1,138 million metric tons (14 percent) lower in 2030 than in the Reference Case; however, they remain 831 million metric tons (14 percent) above 2005 levels. Carbon dioxide emissions from the U.S. transportation sector are reduced by 370 million metric tons (14 percent) in 2030, while electricity sector emissions are reduced by 724 million metric tons (22 percent).

Biomass and Corn Market Impacts

- Biomass consumption for energy uses in the Policy Case rises from less than 30 million tons in 2005 to 571 million tons in 2030, as the power sector and the transportation sector compete for biomass to meet their respective requirements. This level of consumption nearly exhausts the biomass supply represented in the Reference Case, placing upward pressure on biomass prices and raising uncertainty about the ability of the agricultural sector to provide the amounts of biomass that would be required in the Policy Case.

- In the Policy Case, the price of biomass rises from approximately $1.70 per million Btu (roughly $30 per ton) in 2005 to about $5.10 per million Btu (over $88 per ton) in 2030.

- Approximately 9.2 billion bushels of the total 2025 corn production is used to make ethanol in the Policy Case, up from 3.4 billion bushels in the Reference Case. As a result, less corn is available for food and feed.

- Corn prices in the Policy Case increase to about $6.50 per bushel in 2025 (compared with $3.00 per bushel in the Reference Case), then fall to about $6.20 in 2030. Demand for corn-based ethanol remains flat from 2025 to 2030, because of increased cellulosic ethanol production.

Economic Impacts

Achieving the 25-percent renewable fuel target in both the electricity generation and transportation fuel markets leads to higher energy prices, as producers substitute more expensive renewable fuels for less expensive fossil fuels. Higher energy prices reduce economic activity.

- Total GDP losses (discounted at a rate of 4 percent) in the Policy Case relative to the Reference Case over the 2009-2030 period are $296 billion (0.12 percent).

- Cumulative discounted losses in consumer expenditures in the Policy Case relative to the Reference Case over the 2009-2030 period are $149 billion (0.10 percent).

1. Background and Scope of the Analysis

Background

This Service Report was prepared by the Energy Information Administration (EIA) in response to a January 30, 2007, request from Senator James Inhofe.[5] Senator Inhofe requested an analysis of a proposal (referred to as the 25 x 25 Policy Scenario in his letter request) to achieve a 25-percent renewable portfolio standard (RPS) and a 25-percent renewable fuel standard (RFS) by 2025. The combined RPS and RFS policy proposal is referred to as "the Policy" hereafter in the report. Copies of the request letter and a follow-up letter of clarification are provided in Appendix A.

Proposal Summary

The proposal analyzed in this study has two components: (1) an RPS, which requires that the percentage of electricity sales produced from renewable sources, excluding existing hydroelectric generation, must reach 25 percent by 2025; and (2) an RFS, which requires that the volumetric percentage of the transportation gasoline and diesel fuel market supplied from renewable resources, in the form of ethanol and biodiesel, must reach 25 percent by 2025 and then grow proportionately with growth in demand for transportation gasoline and diesel fuel. Each sector (electricity sales and gasoline plus diesel transport fuels) is required to meet its own target by 2025. Twenty-five percent of electricity sales would be from renewable generators and 25 percent of gasoline plus diesel fuel sales would be from either ethanol or biodiesel on a volumetric basis.

A key assumption in both the electricity and transportation sectors is that all tax or other policy incentives for domestic renewable fuels and ethanol import tariffs in current laws and regulations are allowed to sunset without extension.

The RPS target in the electricity sector is implemented using a credit trading system, where the qualifying renewables include:

- Biomass used in dedicated plants or co-fired with other fuels
- Geothermal
- Municipal solid waste (including landfill gas)
- Solar thermal
- Photovoltaic (PV)
- Wind (both onshore and offshore)
- Incremental new hydroelectricity above that existing in 2006.

Further, existing qualifying generators, except existing hydroelectricity, receive credits under the proposed Policy. The renewable share is expressed as a share of electricity sales in kilowatthours. The required share is set equal to the share of qualifying renewable generation sales in 2006 and increases to 25 percent in 2025. Thereafter, it is held at 25

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[5]In followup communications on February 6, 2007, Senate staff also requested that the import tariff on ethanol imports be allowed to sunset, as provided under current law.

percent. All retail electricity sellers are included. RPS credit trading is allowed only within the electricity sector, and there is no cap on the credit price.

The RFS target for the motor transportation sector is also implemented using tradable credits, where the qualifying renewable fuels include:

- Corn-based ethanol
- Cellulose-based ethanol
- Biodiesel production from all sources, including animal fats and oil-based beans/seeds.

As with the RPS, existing qualifying sources receive credits. The renewable share is expressed as a share of all liquids sold in the motor transportation sector that displace either gasoline or diesel. The required share is set equal to the share of qualifying renewables sold in 2006 and increases to 25 percent in 2025. Thereafter, it is held at 25 percent. RFS credit trading is allowed only within the transportation sector, and there is no cap on the credit price. The existing import tariff on Brazilian ethanol imports (51 cents per gallon) is allowed to sunset in 2010. Finally, measures that facilitate compliance with the RFS, such as mandates to produce Flex Fuel Vehicles (FFVs) and the availability of E85 pumps at gasoline dispensing stations, are assumed as stipulated in Senate Bill 23 (S.23).

General Methodology

In this study, analyses of the energy sector impacts and energy-related economic impacts of the Policy proposal are based on the *Annual Energy Outlook 2007* (*AEO2007*)[6] reference and high price cases, as amended to allow for the additional assumptions and modeling enhancements necessary to evaluate the proposal. As in the preparation of the *Annual Energy Outlook* and most EIA service reports, the National Energy Modeling System (NEMS) was used to evaluate the impacts of the Policy Case and alternative assumptions.

A number of changes were made in NEMS to address the Policy and to include enhancements relevant to the analysis. They included changes to the macroeconomic module to improve the representation of the impact on the entire economy of price increases for agricultural products, motor fuel, and electricity; changes in the Petroleum Market Module to ensure convergence of NEMS; and changes to the Renewable Fuels and Transportation Modules to incorporate the proposal's mandates. The changes made to the *AEO2007* NEMS are summarized in Appendix B.

Sensitivity Cases

In addition to the four cases requested by Senator Inhofe (Reference, High Price, Policy, and High Price Policy), four additional cases are provided to illustrate the impacts of higher availability of ethanol imports and more optimistic assumptions for the cellulosic ethanol technology: Low-Cost Ethanol Imports, Low-Cost Ethanol Imports Policy, High Renewable Technology, and High Renewable Technology Policy. The cases analyzed for this request

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[6]Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0838(2007) (Washington, DC, February 2002), web site http://www.eia.doe.gov/oiaf/aeo/index.html.

are shown in Table 1. High Renewable Technology and High Technology are used interchangeably throughout this text.

Table 1. Analysis Cases

Case Name	Description
Reference Case	Based on the *AEO2007* reference case and updated as described above.
High Price Case	Based on the *AEO2007* high price case, but includes revisions adopted in the Reference Case for this study.
Policy Case	Based on the Reference Case for this study, but includes revisions to NEMS modules needed to represent the RPS and RFS policies and incentives.
High Price Policy Case	Based on the *AEO2007* high price case, but includes revisions adopted in the Reference Case and Policy Case for this study.
Low-Cost Ethanol Imports Case	Assumes that prices for U.S. ethanol imports are significantly lower, and that their availability is greater, than in the Reference Case.
Low-Cost Ethanol Imports Policy Case	Combines the assumptions from the Low-Cost Ethanol Imports Case with the Policy Case assumptions.
High Renewable Technology (High Technology) Case	Uses the assumptions of the *AEO2007* rapid renewable generation technology assumptions and the rapid cellulosic ethanol technology progress assumptions with the changes made in the Reference Case for this study. Cellulosic technology capital costs are assumed to decline to $186 million per 50-million-gallon-per-year plant in 2015 and remain constant thereafter. Finally, the “high yield” biomass supply curve was also assumed for the High Technology Case.
High Renewable Technology Policy (High Technology Policy) Case	Combines the assumptions from the High Renewable Technology Case with the Policy Case assumptions.

2. Analytical Issues

All long-term projections contain considerable uncertainty. It is difficult to foresee how existing technologies might evolve or what new technologies might emerge as market conditions change, particularly when those changes are expected to be fairly dramatic. Also, it is difficult to estimate the extent to which consumers will adopt new technologies. Given such uncertainties, meeting the Policy mandates—a 25-percent RPS in the electric power sector and a 25-percent RFS in the motor fuels market by 2025—could be very challenging.

Specifically, the magnitude and pace of infrastructure investments needed, together with uncertainty about the feasibility, cost, and initial date of commercial availability of advanced technologies that do not exist today or currently play a very small role, raise significant concerns. Further, success of the proposed Policy will depend critically on the passage of future enabling legislation compatible with the S.23[7] provisions on FFVs and on the installation of pumps for E85 and biodiesel to make the fuels available to consumers.

Infrastructure, Market, and Technology Concerns

In the electricity sector, the amount of qualifying renewable generation needed to comply with the RPS of the proposed Policy would require about a13-fold increase over the next 18 years from the current U.S. level of nonhydropower renewable generation. In the transportation sector, the amounts of ethanol and biodiesel production needed to comply with the RFS would require more than a 12-fold increase from current levels. While not impossible, such rapid development would be very challenging, and it would carry substantial risk.

Infrastructure Concerns

Meeting the 25-percent RPS target could require more than 100 gigawatts of new wind capacity. Because some of the best wind resources are located in unpopulated areas, distant from demand load centers, significant investments in transmission infrastructure may be needed to develop them. In other cases, offshore wind resources could be an attractive option; and again, new transmission infrastructure would be needed to connect offshore plants to the grid. Developing the necessary transmission infrastructure to take advantage of the best wind resources is certainly technically possible; however, costs and public acceptance are uncertain. For example, recent plans to expand the transmission system through relatively undeveloped areas have met considerable resistance.

Currently, most biofuel production facilities are located close to corn and soybean acreage in the Midwest in order to minimize the transportation costs for bulky, unrefined materials. The facilities are therefore situated far from major consumption centers on the East and

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[7]EIA was asked to adopt two enabling provisions of S.23 as part of the analysis of the Policy proposal. The first provision requires that light-duty vehicle manufacturers must build and certify vehicles that can use high ethanol blends (up to 85 percent ethanol) or diesel and biodiesel blends. The second provision requires that 50 percent of all major-owned or branded gasoline stations must provide dispensing facilities for E85 and biodiesel blends.

West coasts. Additionally, biofuel production generates large supplemental streams of bulky co-products with limited marketability.

Further complicating matters is the fact that biodiesel and ethanol cannot be blended at petroleum refineries and batched through existing pipelines. Ethanol is easily contaminated by water, and biodiesel dissolves entrained pipeline residues. Consequently, railroad cars and tanker trucks made from biofuel-compatible materials must be used to transport large volumes of biofuels to market. Many biofuel producers locate their facilities near dedicated feedstock supplies or large demand centers in order to minimize transportation costs and susceptibility to bottlenecks. Still, limited rail and truck capacity has complicated the delivery of ethanol and contributed to regional ethanol supply shortages and price spikes, as occurred between April and June 2006.

The potential transportation bottlenecks and costs for the biofuels industry are likely to become much more problematic with the proposed Policy than they are today. At the 25-percent RFS level mandated by the Policy, biofuels would significantly penetrate motor fuels markets across the entire United States. The necessary infrastructure for collecting, processing, and distributing large volumes of biofuels would have to be expanded or, in many cases, created. Without substantial infrastructure investment, it would be difficult or impossible for producers to avoid bottlenecks in the transportation and delivery of biofuels to market.

There are also other factors that could hamper the distribution of biofuels to end-use markets. Although E10 (“gasohol”) is readily dispensed throughout the United States, there are limited numbers of fueling stations for biodiesel and E85—currently, less than 1 percent of the total number of U.S. vehicle fueling stations. S.23, if passed, would require approximately 50 percent of “majors and branded” motor fuel dispensing stations (roughly 25 percent of all U.S. fueling stations) to install “high biofuel blend” pumps for E85 and/or B20.

Recent EIA estimates for replacing one gasoline dispenser and retrofitting existing equipment to carry E85 at an existing fueling station range from $22,000 to $80,000 (2005 dollars), depending on the scale of the retrofit. By these estimates, the total investment cost for installation of biofuel pumps would range from about $0.8 billion to about $3 billion. To recoup the investment costs over a 15-year period, assuming that an E85 pump would dispense one-half the volume of an average unleaded gasoline pump (about 160,000 gallons per year), the retail price of E85 would have to be raised by 2 to 7 cents per gallon.

The *total* infrastructure investment costs that would be required to support the 25-percent RFS have not been estimated. Further, some of the majors and branded dispensing stations may choose to sell their less profitable station holdings (they would become unbranded and non-major owned) to avoid the expense, and that could reduce the availability of E85 dispensing stations to consumers, making market acceptance of E85 slower.

Market Concerns

Market concerns arise both from the uncertainty inherent in petroleum and agricultural markets and from the linkage of food and fuel markets that would result from implementation of the RFS policy. With respect to petroleum, the current volatility of crude oil markets casts doubt on the potential for biofuels to remain competitive in the future without government mandates, such as the S.23 and this RFS policy proposal. With an RFS, fuel price risks are shifted to consumers through the price of credits; however, consumer acceptance, awareness, and willingness to use biofuels, as well as manufacturers' willingness to produce FFVs, are unknown (and unlikely without a government mandate). The costs associated with vehicle manufacturing also are shifted to consumers under an RFS mandate, but again there is no guarantee that consumers will choose to purchase E85 or biodiesel fuels in the quantities needed to fulfill the mandate.

The RFS, which requires biofuels production to reach approximately 65 billion gallons by 2025, could require more than 25 billion gallons of corn-based ethanol and 25 billion gallons of cellulosic ethanol, a technology that is not commercially available at present. It could also require a roughly 8-fold increase in ethanol imports as well as about 5 billion gallons of domestic biodiesel production. As a result, domestic corn and soybean prices could increase dramatically from current levels, significantly increasing domestic prices for food and feed and reducing exports.

In agricultural markets, production of corn and biomass is subject to agricultural risks, such as crop failure caused by disease or drought. Moreover, the competition for arable land that would result from increased corn production at the levels needed to satisfy the 25-percent RFS could significantly raise all food and feed prices in the United States. The current generation of corn and soy biofuels crops are grown almost exclusively on prime agricultural land in the Midwest. It is not clear that sufficient land resources would be available for large-scale expansion of corn and soybean cultivation, given the intense competition with conventional agricultural products for arable land.

The markets for biofuels, biofuel co-products, and crop commodities are linked, and they are susceptible to changes in the prices and availability of the crops. Surging demand for biofuel feedstocks under the RFS policy would exert upward price pressure on corn and soybean commodities and influence the markets for food, feed, industrial feedstocks, and exports. Additionally, the generation of co-products increases directly with biofuel production. At high levels of biofuel production, co-products may be oversupplied, resulting in depressed prices and lower revenues to offset fuel production costs.

In 2005, co-products from the 3.9 billion gallons of ethanol produced were significant, including 10 million tons of dried distillers' grains and solubles (DDGS), 473,000 tons of corn gluten meal, 2.6 million tons of corn gluten feed, and 283,000 tons of corn oil.[8] As biofuel production grows to the 7.5 billion gallons mandated in the Energy Policy Act of 2005 (EPACT2005), DDGS production is expected to grow to more than 15 million tons. With the RFS policy, more than 25 billion gallons of corn-based ethanol would be required in 2025, and DDGS production would exceed 50 million tons—probably causing a dramatic drop in its market-clearing price. At that point, the value of DDGS could be as low as the value of biomass or fertilizer.

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[8]Renewable Fuels Association, *2005 Annual Industry Outlook*, web site http://www.ethanolrfa.org/industry/outlook/.

Biodiesel production also results in some valuable co-products. Current biodiesel production uses surplus soybean oil generated as a co-product in the soybean meal industry, with little effect on other soybean commodity markets. Annual production levels approaching 300 to 600 million gallons of soybean oil would, however, begin to compete with food and feed markets for soybeans.[9] Ten pounds of crude glycerol is generated as a co-product for every 100 pounds of biodiesel, and the glycerol generated from 300 to 600 million gallons of biodiesel production per year would be equal to nearly one-half of the current glycerol market in North America, causing a substantial oversupply and depressing prices.

Technology Concerns

Meeting the 25-percent RFS and RPS mandates in the Policy proposal would require successful and early development of currently unproven and noncommercial technologies, including those that convert cellulose to sugars and, ultimately, to cellulosic ethanol. The success of the Policy would also depend on the cost, performance, and first date of commercial availability of advanced biomass electricity generation technology and the development of the energy crop industry needed to support it.

While it is expected that both technologies—advanced biomass generation and cellulosic ethanol production—will be feasible, their actual costs, performance, and first dates of commercial availabilities are uncertain, because no such commercial plants exist at present. If the technologies became commercially available in the first few years of the next decade and their costs were lower than expected, then the costs of meeting the RPS and RFS could be lower than projected here. On the other hand, if the costs of early commercial plants were much higher than projected[10] and/or the first dates of commercial availability were delayed into the second half of the next decade or beyond, then the actual costs of the policy could be much higher than estimated in this analysis. In that event, meeting the RFS by 2025 could require potentially implausible levels of corn-based ethanol production or unprecedented levels of ethanol imports from Brazil. With the success of the Policy dependent on noncommercial technologies with significant uncertainty in cost, performance, and date of commercial availability, significant economic risks would be imposed on the market.

In the case of electricity generation from biomass, the technology consists of a biomass handling preprocessor that reduces the biomass to a treatable consistency; a gasifier and scrubber to remove noxious or corrosive gases in the mix; and a combined-cycle generating plant. In concept, the technology is much like an integrated gasification combined-cycle (IGCC) plant with coal as the feedstock; however, no full-scale commercial IGCC plants have been built. The major engineering issue with biomass remains the "front end handling and processing" component, which tends to jam or clog. Small-scale pilot plants have not

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[9]Promar International, "Evaluation and Analysis of Vegetable Oil Market: The Implication of Increased Demand for Industrial Uses on Markets & USB Strategy" (November 2005), pp. 25-35, web site http://www.nbb.org/resources/reportsdatabase/reports/gen/20051101_gen-368.pdf.
[10]Precommercial engineering estimates of capital and operating costs of new technologies tend to understate the costs of the first few commercially available plants; there is generally no evidence to suggest that the cellulosic ethanol technology will prove otherwise.

attained utilization rates exceeding 60 percent. Because the front end is an expensive component, either the engineering problem must be solved or the unit will have to be built with a “spare front end handler” to maintain high overall utilization, significantly increasing its capital and nonfuel operating and maintenance costs.

In the case of cellulosic ethanol, current estimates of capital costs for a 50 million gallon per year cellulosic ethanol plant are expected to be high: about $365 million (2005 dollars), as compared with $65 million for a corn-based plant of similar size. With no commercial cellulosic ethanol plants currently in operation, investment risk is high for a first-of-its-kind, large-scale cellulosic ethanol production facility. EPACT2005 provides financial incentives that are expected to bring the first 250 million gallons per year of cellulosic ethanol production capacity on line between 2010 and 2015; however, it is not certain what the initial plant and operating costs will be or how quickly the costs and investment risk will fall as a result of manufacturing experience and further research.

Other Concerns and Uncertainties

In addition to the concerns discussed above, there are several other areas of uncertainty that could affect the feasibility and costs of meeting the RPS and RPS policy goals.

- The supply and cost of biomass energy crops to generate electricity and produce cellulose-based ethanol will be critical in determining credit prices and the prices of delivered energy under the main Policy. The critical uncertainty involves the availability and cost of biomass for use in electric power generation and ethanol production, as well as the cost, performance, and first dates of commercial availability of the technologies. To the extent that this analysis overstates the cost and understates the availability of biomass technology, the impact on the U.S. energy market and economy could be smaller than indicated here; however, if biomass supply is overstated and prices are understated here, the impact could be larger.

- The projected level of about 25 billion gallons of corn ethanol production in 2025 under the Policy would significantly increase U.S. corn demand and likely require much higher prices to clear the market, with a significant impact on food and feed markets and a large cut in, or elimination of, U.S. corn exports. Also, several recent studies that are less optimistic about yield growth and expansion of corn acreage suggest a maximum level of U.S. corn ethanol production that is below 20 billion gallons, which would make the feasibility of meeting the RFS much more uncertain.

- The impacts of rising corn prices on the prices of other domestic and international agricultural food and feed products—and ultimately on U.S. economic growth—is highly uncertain but potentially larger than the direct energy price impacts alone. Analysis of those impacts would require the application of an integrated model that examines agricultural competition across the economy and energy sectors both domestically and internationally. For this study, EIA used an integrated domestic model to derive biomass and corn prices; however, the model is not integrated with the rest of the domestic or international economy.

- The availability and pricing of ethanol exports from Brazil will be critical in determining domestic RFS credit prices. Further, the availability of ethanol exports will depend on the extent to which additional land resources are used for ethanol production, which is highly uncertain. Although Brazil may be willing to make such investments, it is unclear at what market price the investments would be made or how they would be funded.

- As indicated in the request for analysis, this study assumes the enactment, in some form, of legislation (like portions of S.23) that will facilitate the development of biofuels transportation and distribution infrastructure and the production of only dual-fuel capable light-duty vehicles after 2016. The enactment of such legislation is highly uncertain. Its details could determine what the costs are, who bears the costs of building the infrastructure, and the likelihood that the intended goals will be achieved.

Uncertainties in the Reference Case

NEMS, like all models, is a simplified representation of reality. Projections are dependent on the data, methodologies, model structure, and assumptions used to develop them. Because many of the events that shape energy markets (including severe weather, technological breakthroughs, and geopolitical developments) are random and cannot be anticipated, energy markets are subject to uncertainty. Moreover, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Nevertheless, well-formulated models are useful for analyzing complex policies. They can provide valuable insight, because they ensure consistency in accounting and represent (albeit imperfectly) key interrelationships.

EIA's projections are not statements of what will happen, but what might happen, given technological and demographic trends and current policies and regulations. The Reference Case used for this analysis, based on the *AEO2007* reference case, incorporates current laws and regulations as of September 1, 2006. Thus, it provides a policy-neutral starting point that can be used to analyze energy policy initiatives. In its reference cases, EIA does not propose, advocate, or speculate on future legislative or regulatory changes. Laws and regulations generally are assumed to remain as currently enacted or in force (including sunset or expiration provisions); however, the impacts of scheduled regulatory changes, when clearly defined, are reflected.

This report, like other EIA analyses of energy and environmental policy proposals, focuses on the impacts of those proposals on energy choices made by consumers in all sectors and the implications of those decisions for the economy. This focus is consistent with EIA's statutory mission and expertise. The study does not account for any possible health or environmental benefits that might be associated with enactment of a combined RPS and RFS.

3. Energy Market Impacts of the Renewable Policy Proposal

Electricity Sector Impacts

Implementing a 25-percent RPS by 2025 has significant impacts on power sector generation by fuel, generating technology selection, and electricity prices. The power sector shifts away from its long-term reliance on coal-fired generation, toward increased reliance on nonhydropower renewable generation and incremental hydroelectric generating sources. This trend has little impact on emissions of sulfur dioxide, nitrogen oxides, and mercury. Because these three pollutants are subject to emissions caps, their levels are essentially unchanged (although the costs of compliance are lower). However, the change in fuel mix leads to somewhat lower carbon dioxide (CO_2) emissions, which currently are not regulated. The higher cost of renewable generating technologies results in lower delivered prices for fossil fuels but higher electricity prices overall. Table 2 summarizes key electricity sector impacts.

RPS Credit Prices

The RPS credit price, shown in Table 2 for 2025 and 2030, generally increases through 2025, when the maximum required share for renewable generation is initially imposed. Between 2025 and 2030, the credit price is projected to vary between 3.8 and 4.8 cents per kilowatthour. The credit price represents the incremental cost of meeting the specified renewable target. Essentially, it describes the difference between the cost of the cheapest available renewable option that satisfies the requirement and the alternative technology that would have supplied the electricity if the RPS had not been in place. Naturally, the credit price is affected by the costs and performance of the available renewable options and the alternative nonrenewable technologies. Figure 1 illustrates the RPS credit prices in the Policy Case.

Inter-sector Compliance Options

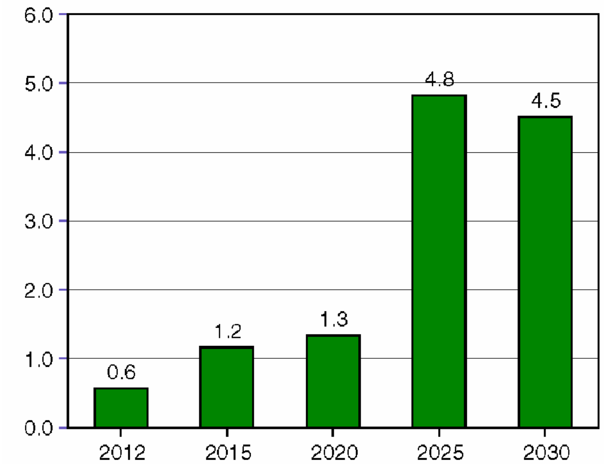
The proposed Policy analyzed in this report calls for compliance with separate renewable sales targets in the electricity and transportation sectors. The marginal cost of compliance, as reflected by the credit price for each sector, would not be expected to be the same for each sector, as each has different compliance options. Both sectors can and do use significant amounts of cellulosic biomass as part of the compliance strategy, and at times this may represent the marginal unit of supply to one or both sectors. Even so, costs may differ between the two sectors, as each has different conversion efficiencies and capital and non-feedstock operating costs.

Table 2. Selected Electric Power Results, 2025 and 2030

	2005	2025		2030	
		Reference	Policy	Reference	Policy
RPS Credit Price (2005 cents/kWh)	**NA**	**NA**	**4.8**	**NA**	**4.5**
Capacity (gigawatts)					
Coal Steam	314.8	406.1	323.4	468.0	342.5
Other Fossil Steam	121.4	88.3	80.9	87.0	80.9
Combined Cycle	176.6	210.4	196.0	211.6	196.6
Combustion Turbine/Diesel	133.2	135.1	146.5	154.2	178.9
Nuclear Power	100.0	111.7	102.7	109.1	98.9
Pumped Storage	20.8	20.8	20.8	20.8	20.8
Other	0.0	5.6	8.1	11.4	13.2
Conventional Hydropower	80.6	80.8	85.9	80.8	85.9
Geothermal	2.3	3.0	8.6	3.2	9.6
Municipal Solid Waste/Landfill Gas	3.6	4.1	5.8	4.2	5.9
Wood and Other Biomass	6.5	9.8	75.1	11.7	84.5
Solar[1]	0.6	2.1	2.0	3.6	3.8
Wind	9.6	17.8	130.6	17.9	144.4
Other Industrial Capacity[2]	17.7	31.1	33.4	35.1	39.6
Total	**987.7**	**1,126.7**	**1,220.0**	**1,218.4**	**1,305.6**
Generation (billion kilowatthours)					
Coal	2,014.6	2,852.6	2,161.7	3,320.0	2,382.2
Petroleum	121.9	105.0	101.4	107.0	102.9
Natural Gas	751.7	1001.0	768.3	938.0	838.8
Nuclear Power	780.5	886.0	815.2	869.5	789.4
Pumped Storage/Other	13.0	8.0	8.1	8.5	8.6
Conventional Hydropower	265.1	307.5	328.3	307.7	328.4
Geothermal	15.1	21.6	66.1	23.1	73.8
Municipal Solid Waste/Landfill Gas	23.3	27.2	40.4	27.7	40.8
Dedicated Biomass	30.5	57.0	535.9	69.5	605.3
Biomass Co-Firing	7.4	67.2	83.7	66.8	26.4
Solar[1]	0.9	4.4	4.2	7.2	7.6
Wind	14.6	51.3	425.1	51.5	475.2
Total	4,038.4	5,388.9	5,338.2	5,796.6	5,679.4
Electricity Prices and Sales					
Electricity Sales (billion kiowatthours)	3,660.0	4,825.9	4,778.3	5,168.4	5,056.6
Retail Electricity Prices (2005 cents/kWh)	8.1	8.0	8.3	8.0	8.5
Electric Sector Emissions					
Sulfur Dioxide (million short tons)	10.2	3.7	3.6	3.7	3.6
Nitrogen Oxides (million short tons)	3.6	2.3	1.9	2.3	2.0
Mercury (tons)	51.2	16.9	16.9	16.5	15.7
Carbon Dioxide (million metric tons)	2,375	3,046	2,425	3,321	2,597
Fuel Prices					
Natural Gas Wellhead Price (2005 dollars per mcf)[3]	7.51	5.54	5.47	5.90	5.86
Coal Minemouth Price (2005 dollars per ton)	23.34	21.83	21.34	23.17	21.73

[1]Includes solar thermal power, utility-owned photovoltaics, and distributed photovoltaics.
[2]Includes capacity in the industrial sector fueled by petroleum, natural gas, or other gaseous fuels.
[3]mcf = thousand cubic feet. kWh = kilowatthour.
Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

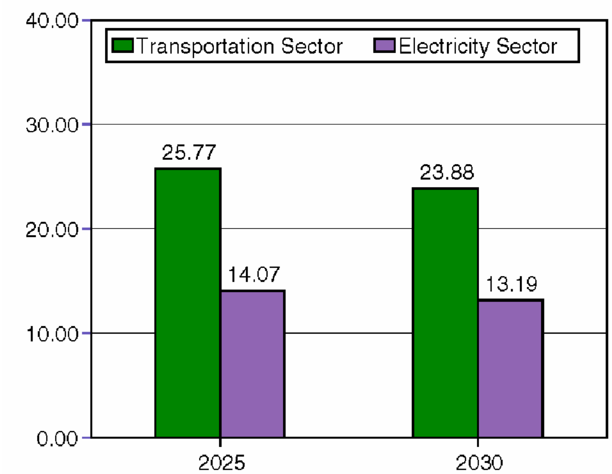
Figure 1. Renewable Portfolio Standard Credit Price, Policy Case
(2005 cents per kilowatthour)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

If the proposed Policy were applied as an aggregate target for the two sectors, with credit trading allowed between the sectors (that is, 25 percent of the combined electricity and motor transportation fuels markets), the credit prices in the two sectors would converge to a common value. Currently, the electricity sector target is specified in cents per kilowatthour and the transportation sector target in dollars per gallon of ethanol. A joint target would require a common unit of comparison, as shown in Figure 2 for the Policy Case.

Figure 2. Comparison of RFS and RPS Credit Prices in Common Units, Policy Case
(2005 dollars per million Btu)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

The higher credit price in the transportation sector indicates that an aggregate target would encourage more compliance in the electricity sector and reduced compliance in the transportation sector. More than 25 percent of the electricity generated in the electricity sector would be from renewable fuels, and less than 25 percent of the motor transportation fuels would be biofuels. The shift in the compliance burden between sectors would tend to reduce the overall cost of compliance; however, EIA is not able to determine the impact of such a scheme without specification of a mechanism for inter-sector credit trading.

Generation by Fuel

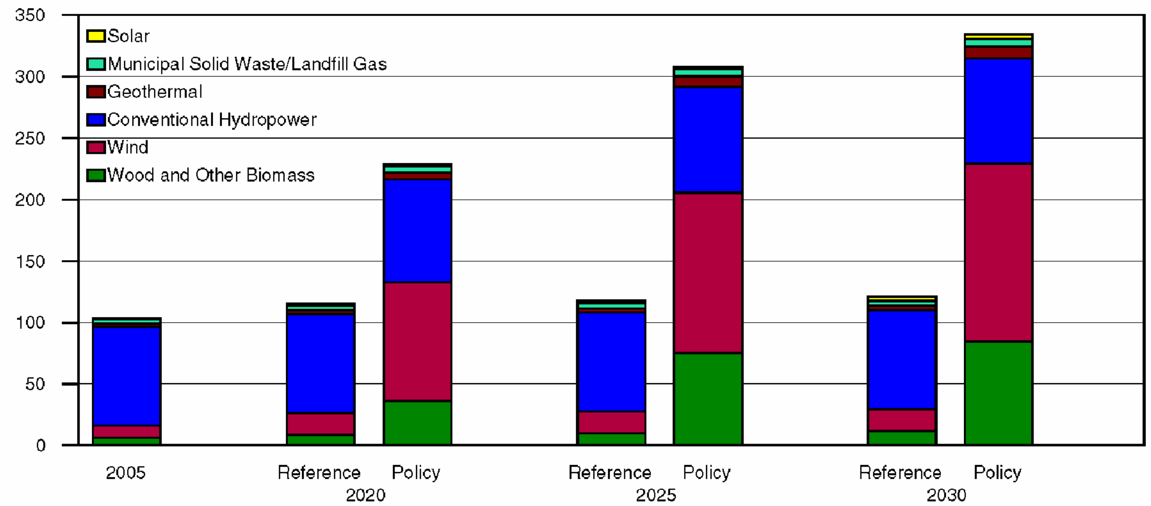
In the Reference Case, coal-fired plants continue as the primary source of electricity, increasing from about 50 percent of total supply in 2005 to 53 percent in 2025 (Table 2). Both nuclear and natural gas plants provided 19 percent of total generation in 2005. Nuclear generation is projected to increase over the subsequent 20 years but at a slower rate than total generation, and so the share of generation from nuclear plants in 2025 falls to 16 percent. Natural gas generation is projected to rise initially but then decline as natural gas prices increase. In 2025, the share of total generation from natural gas plants is projected to be about 19 percent—about the same share as in 2005. In 2030, nuclear power generation falls slightly from 2025 levels due to some age-related retirements, and its share of electricity generation falls to 15 percent. Natural gas power generation falls by about 6 percent from 2025 levels as increasing natural gas prices erode its competitiveness, and its total market share falls to about 16 percent in 2030 (Table 2).

Hydroelectric plants are the largest source of renewable generation, but production from existing facilities is not credited toward the RPS requirement. The share of hydroelectric generation declines in the Policy Case from about 6.5 percent of total supply in 2005 to 6 percent in 2025. Nonhydropower renewables remain a small source of electricity in the Reference Case, but the corresponding share of total generation doubles from 2 percent in 2005 to 4 percent in 2025. Biomass and wind plants represent the primary sources of nonhydropower renewable generation. Production from both these technologies more than triples between 2005 and 2025, although their share of total generation remains small throughout the projection.

In general, biomass and wind electricity supplies are projected to represent the primary options for complying with the RPS. Although total wind capacity exceeds biomass capacity (Figure 3), biomass generation is considerably higher than the output from wind capacity (Figure 4) because of a higher biomass capacity factor. Dedicated biomass plants have higher utilization rates than wind plants, which are dependent on an intermittent resource. Also, biomass can be co-fired with coal in existing fossil steam units.

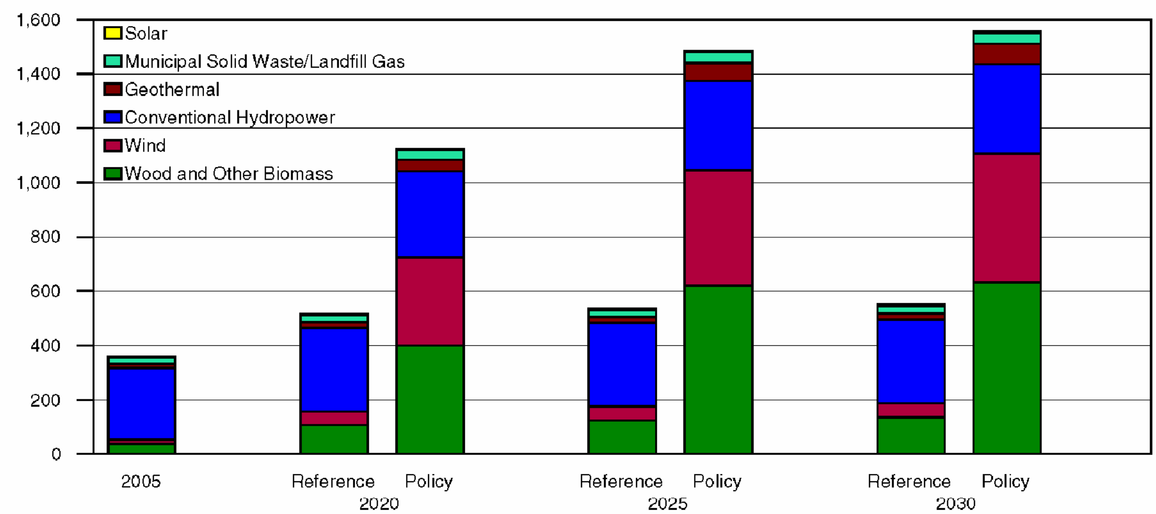
In the Policy Case, biomass generation in 2025 and 2030 provides about one-half of the renewable generation required by the RPS (Table 2). Considerable increases in biomass electricity generation occur in virtually every region of the United States. Wind plants account for more than 35 percent of the RPS requirement in 2025 and 2030. Most of the wind capacity additions are expected to be built in the West and Midwest. More moderate increases are projected for geothermal, municipal solid waste, and hydroelectric technologies, which together supply about 10 percent of the needed renewable generation. Little change in solar generation is expected as a result of the RPS (Table 2).

Figure 3. Renewable Generation Capacity, Reference and Policy Cases
(gigawatts)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Figure 4. Renewable Generation, Reference and Policy Cases
(billion kilowatthours)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

The requirement for renewable generation specified in the RPS is expected to reduce electricity production from other fuel types. Compared to the Reference Case, coal-fired generation is about 24 percent lower in 2025 and 28 percent lower in 2030 in the Policy Case. Natural-gas-fired generation is 23 percent lower in 2025 and 11 percent lower in 2030 in the Policy Case than in the Reference Case (Table 2). Similarly, nuclear generation is about 8 percent less in 2025 and 9 percent less in 2030.

With biomass expected to be the leading renewable option for satisfying the RPS, the availability of biomass fuel supplies has a considerable impact on the ability of the electric power sector to comply with the RPS. Some biomass feedstocks can be used for both electricity production (dedicated biomass plants and co-firing in coal-fired plants) and cellulosic-based ethanol, and the respective sectors compete for those common resources in order to comply with the RPS and RFS. If more economical supplies of imported ethanol were available, then less biomass fuel would be needed to produce cellulose-based ethanol, and more would be available for electricity generation.

Carbon Dioxide Emissions

In the Reference Case, CO_2 emissions resulting from electricity generation grow from 2,375 million metric tons in 2005 to 3,046 million metric tons in 2025, an increase of almost 30 percent (Table 2). The increase in emissions results from higher fossil fuel consumption, particularly coal.

In the Policy Case, the increased penetration of renewable generating plants displaces some generation from fossil plants and slows the growth in CO_2 emissions (Table 2). CO_2 emissions in 2025 total about 2,425 million metric tons, which represents a reduction of about 20 percent from the Reference Case and only a slight increase from 2005 levels.

Electricity Prices

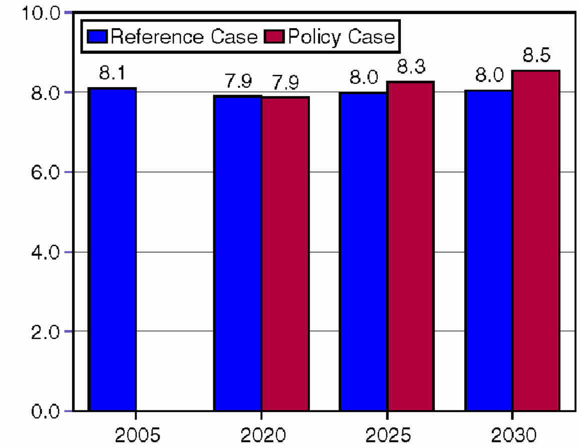
In the Reference Case, electricity prices are expected to decline from 2005 to 2015 and then increase gradually, so that the prices in 2025 and 2030 are similar to the price in 2005 (Table 2 and Figure 5). The initial decline in prices results from a corresponding decrease in fuel prices and comparatively few capacity additions (because some areas currently have a surplus of generating capacity). Between 2015 and 2025, fuel prices to electricity generators start to rise, and more new plants are required to meet projected increases in demand.

Compared to the Reference Case, the cost of complying with the RPS in the Policy Case is projected to increase the price of electricity by about 3.3 percent and 6.2 percent in 2025 and 2030, respectively (Table 2 and Figure 5). Although the increased renewable generation resulting from the RPS displaces fossil generation and results in lower fuel prices, that decrease is more than offset by the higher cost of building and operating renewable capacity per unit of output.

The RPS could, however, result in lower electricity prices in some areas of the United States. The Western Regions have considerable renewable resources that could enable suppliers to provide renewable generation in excess of their own requirements and sell surplus credits to producers in other areas with less economical renewable options. The resulting revenue could more than offset the costs of building renewable plants in the West.

Consumers' expenditures for electricity in the Policy Case are $9 billion higher than in the Reference Case in 2025 and $16 billion higher in 2030. The higher electricity bills are partially offset by lower consumer natural gas bills. Through 2022, however, electricity prices in the Policy Case are generally lower than in the Reference Case, because the cost of generation declines more than the cost of capital increases.

Figure 5. Electricity Prices, Reference and Policy Cases
(2005 cents per kilowatthour)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Relative to the Reference Case, end-use sector expenditures for purchased electricity rise while end-use sector expenditures for natural gas fall in the Policy Case. From 2009 through 2030, cumulative expenditures for electricity (discounted at 7 percent) are $15 billion (0.4 percent) higher and natural gas expenditures are $17 billion (1.0 percent) lower in the Policy Case than in the Reference Case.

End-Use Energy Consumption

Consumers and businesses in all sectors of the economy are projected to reduce their electricity consumption and increase their direct use of fossil fuels in response to the higher delivered electricity prices in the Policy Case. These changes reduce overall energy consumption but raise consumers' energy bills.

Residential and Commercial Sectors

There is little change in residential and commercial energy consumption in 2025 in the Policy Case relative to the Reference Case. Lower electricity consumption is offset by increased natural gas consumption. In both sectors, total delivered energy use[11] in 2025 is 0.1 percent lower in the Policy Case than in the Reference Case (Figures 6 and 7).

Residential electricity demand is 0.5 percent lower and commercial electricity demand is 0.3 percent lower in 2025 in the Policy Case than in the Reference Case, because electricity prices rise as suppliers pass along the costs of holding renewable credit permits and because of increased renewable fuel use. In 2030, electricity demand in the Policy Case is 1.0 percent lower in the residential sector and 1.1 percent lower in the commercial sector than projected in the Reference Case.

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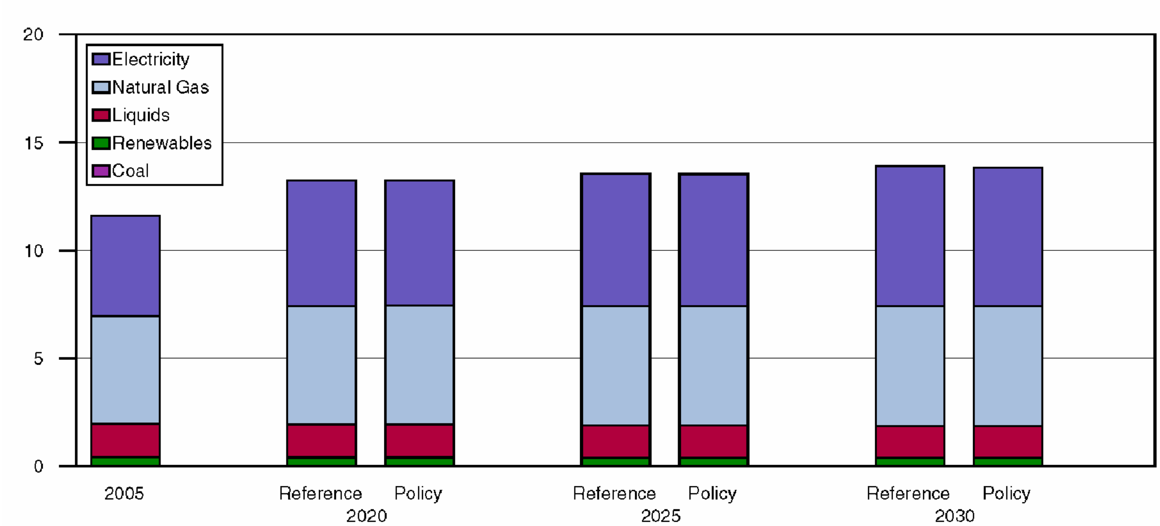
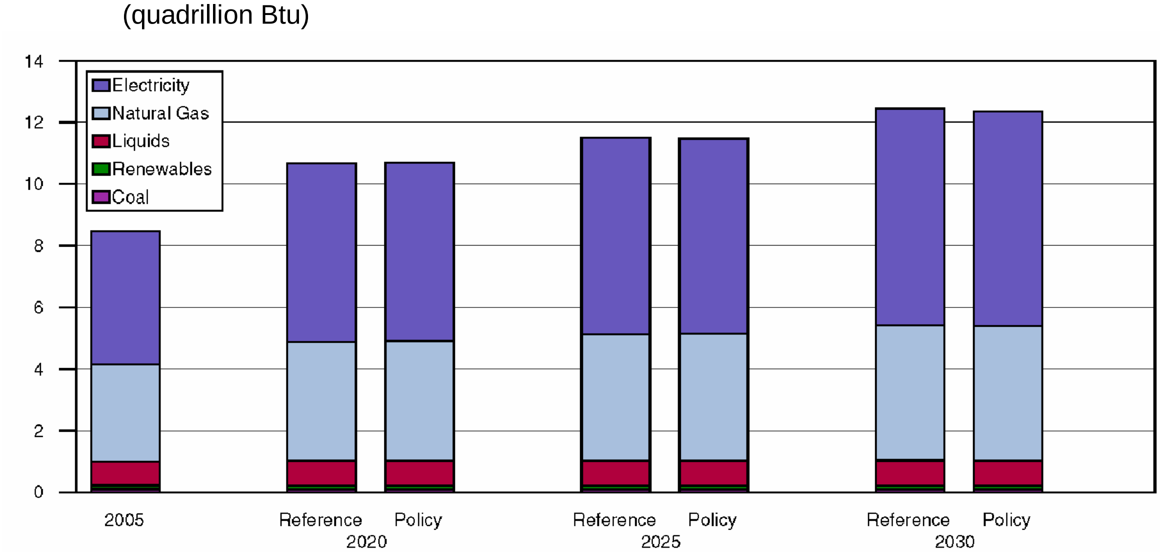
[11]Delivered energy does not include losses associated with the conversion and distribution of electricity.

Figure 6. Delivered Residential Energy Consumption, Reference and Policy Cases
(quadrillion Btu)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Figure 7. Delivered Commercial Energy Consumption, Reference and Policy Cases
(quadrillion Btu)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Increased use of renewable fuels leads to lower natural gas consumption in the electric power sector and, in turn, to lower natural gas prices in the Policy Case relative to the Reference Case. As a result, residential natural gas use is 0.2 percent higher and commercial natural gas use is 0.4 percent higher in 2025 in the Policy Case than in the Reference Case.

In the commercial sector, petroleum liquids consumption is 1.2 percent lower in 2025 in the Policy Case than in the Reference Case as a result of higher commercial distillate fuel prices. Although the price of heating oil in the Policy Case is similar to that in the Reference Case, the price of diesel fuel for commercial engines is higher than in the Reference Case, leading to lower commercial demand for petroleum.

Annual residential and commercial energy expenditures are higher with implementation of the Policy proposal. Residential energy expenditures increase by 1.5 percent ($30 per household) in 2025 in the Policy Case relative to the Reference Case due to higher electricity prices. The change in commercial energy expenditures with enactment of the Policy proposals is similar to that in the residential sector. Commercial energy expenditures are 2.3 percent higher in 2025 in the Policy Case than in the Reference Case.

Higher electricity prices relative to natural gas prices in the Policy Case lead to 2.3 percent more commercial natural-gas-fired combined heat and power (CHP) capacity in 2025 relative to the Reference Case. In 2030, the higher relative electricity prices result in 19 percent more natural-gas-fired CHP capacity in the Policy Case compared to the Reference Case. Higher electricity prices in the Policy Case also lead to more use of PV systems in the buildings sectors. Residential and commercial PV capacity in 2030 is 9.6 percent higher in the Policy Case than in the Reference Case.

Industrial Sector

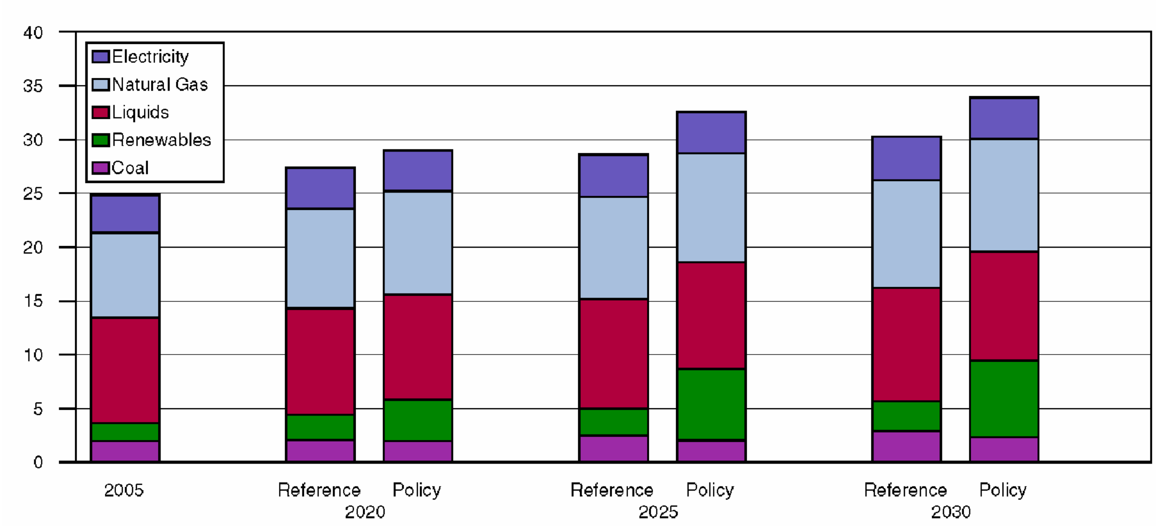
Industrial energy consumption is higher in the Policy Case due to large increases in the use of biofuels and heat co-products for ethanol production. Total delivered industrial energy consumption is 33.9 quadrillion Btu in 2030 in the Policy Case, compared with 30.3 quadrillion Btu in the Reference Case. The increase in industrial sector consumption of biofuels and natural gas in the Policy Case more than offsets a decline in coal use. In 2030, industrial consumption of biofuels and heat co-products increases from 0.8 quadrillion Btu in the Reference Case to 5.2 quadrillion Btu in the Policy Case, as a result of the increase in production of biomass-derived transportation fuels. Cellulosic ethanol production increases from 0.2 billion gallons to 31 billion gallons; the amount of corn used to produce ethanol increases by 107 percent; and biodiesel production increases from 1.6 billion gallons to 4.8 billion gallons.

Increased ethanol production also results in a sharp increase in natural gas use for heat and power production at ethanol plants, which in 2030 increases from 0.3 quadrillion Btu in the Reference Case to 0.8 quadrillion Btu in the Policy Case. Natural-gas-fired CHP plants are also responsible for increased natural gas consumption, particularly in response to higher electricity prices after 2020. An additional 4.3 gigawatts (18 percent) of natural-gas-fired CHP capacity is added in the Policy Case. Overall, industrial natural gas consumption averages 5 to 8 percent (400 to 600 trillion Btu) higher in the Policy Case than in the Reference Case (Figure 8).

The increases in consumption of biofuels, heat co-products, and natural gas are partially offset by a drop in the use of coal to produce liquids and electricity in coal-to-liquids (CTL) plants. CTL liquids production in 2030 falls from 445 thousand barrels per day in the Reference Case to 202 thousand barrels per day in 2030 in the Policy Case. As a result, total coal use at CTL plants is reduced by 55 percent, from 112 million tons in the Reference Case to 51 million tons in the Policy Case.

The net economic impact of the Policy Case is a reduction in industrial value of shipments, by 3.3 percent in 2030 compared with the Reference Case. All industries are adversely affected to some degree. Among manufacturing industries, petroleum refining has the largest percentage decline in output (12 percent in 2030), followed by the aluminum industry (8 percent) and the steel industry (6 percent).

Figure 8. Industrial Energy Consumption, Reference and Policy Cases
(quadrillion Btu)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

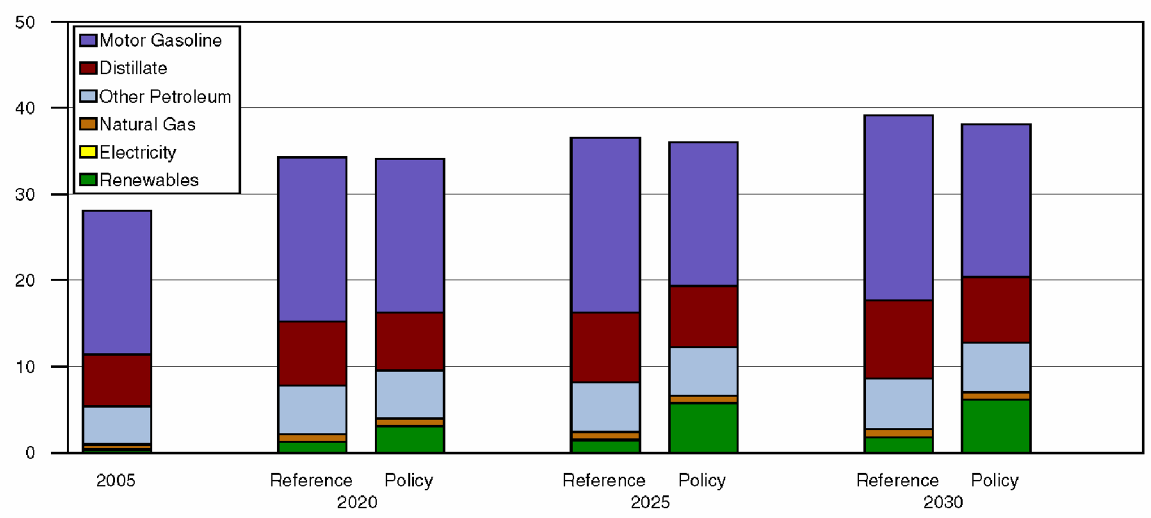
Transportation Sector

In the transportation sector, total energy consumption in 2025 and 2030 in the Policy Case is slightly lower than in the Reference Case (Figure 9). Total transportation energy consumption increases from 28.1 quadrillion Btu in 2005 to 36.5 quadrillion Btu in 2025 and 39.1 quadrillion Btu in 2030 in the Reference Case. Total transportation energy consumption in the Policy Case is 0.6 quadrillion Btu (1.5 percent) lower in 2025 and 1.0 quadrillion Btu (2.6 percent) lower in 2030, as a result of reductions in freight travel (due to reduced industrial output) and in fuel use for light-duty vehicle travel (associated with higher driving costs).

Ethanol and biodiesel consumption in the Policy Case represents a much larger share of highway liquid fuel use than in the Reference Case. On an energy basis, renewable fuels account for 5.0 percent and 5.6 percent of highway liquid fuel use in the Reference Case in 2025 and 2030, respectively. In the Policy Case, renewable fuels account for about 20 percent of highway liquid fuels consumption on an energy basis in 2025 and in 2030.

To facilitate compliance with the renewable fuel supply and consumption mandate, policies consistent with those outlined in S.23, the Biofuels Security Act of 2007, were adopted in this analysis. S.23 stipulates minimum requirements for the manufacture of dual-fuel capable light-duty vehicles and the installation of E85 fuel pumps by major oil companies at owned and branded stations. It requires that 100 percent of light-duty vehicles manufactured after 2016 must be dual-fuel capable and that 50 percent of owned and branded stations must install one or more pumps that dispense E85 fuel. However, two aspects of S.23 were not considered in this analysis: the requirement for specific minimum E85 sales volumes and the provisions for Corporate Average Fuel Economy credits from the manufacture and sale of dual-fuel vehicles.

Figure 9. Transportation Energy Consumption, Reference and Policy Cases
(quadrillion Btu)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

EIA data indicate that approximately 50 percent of all retail fuel sales occur through owned and branded retail outlets, which equates to a consumer fuel availability value of 25 percent.[12] Expected penetration rates of new dual-fuel vehicle sales and E85 fuel availability are illustrated in Figure 10.

Although the Policy Case requires the installation of E85 fueling infrastructure to begin by 2008 and reach the maximum share by 2017, the projections indicate that E85 will not become a cost-competitive alternative to gasoline until 2015. As a result, the projections indicate that the E85 infrastructure requirements considered in the analysis could be delayed by as much as 7 years.

The cost of installing E85 retailing infrastructure and the associated impact on fuel cost and fuel retailer profitability were not considered in this study. An EIA analysis of the incremental cost associated with retrofitting an existing gasoline station to dispense E85 indicates that the costs could vary widely, depending on the scale of the retrofit and the annual volume of E85 dispensed.[13] At 40 thousand gallons per year, the estimated incremental charge required to recover the cost over 15 years ranges from 8 cents per gallon

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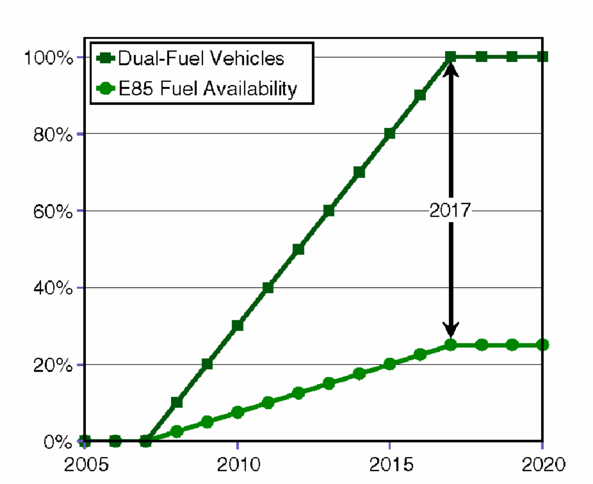
[12]It was determined that retail sales volumes were a better indicator of the potential fuel availability to consumers than the number of retail outlets offering an alternative fuel. The intent of this assumption is to capture consumer access/through rates at regulated stations versus those not required to provide the alternative fuel. The retail sales volumes were determined by assuming that fuel marketers required to report on Form EIA-28 fit the owned and branded requirement defined in S.23 (see http://www.eia.doe.gov/emeu/perfpro/btab30.html).
[13]Energy Information Administration, *Incremental Costs of Installing E-85 Dispensers at Gasoline Stations* (Washington, DC, July 21, 2005).

for a minimal retrofit (tank cleaning and nozzle, hose, and filter replacement) to 29 cents per gallon for the replacement of the existing underground tank and dispenser with E85-compatible equipment. As annual E85 pump volumes approach 50 percent of equivalent unleaded gasoline pump volumes (about 160,000 gallons per year), the incremental costs decrease significantly and could vary from 2 cents per gallon to 7 cents per gallon depending on the scale of the retrofit. The incremental costs per gallon are 2 to 3 times higher if the cost recovery period is reduced to 5 years. These estimates do not account for any gains or losses in revenues that may result from replacing an unleaded gasoline dispenser with an E85 dispenser. In the initial years of operation, fuel-related revenues are likely to be lower if an existing gasoline tank and dispenser are replaced with E85 equipment.

Figure 10. Minimum Requirements for New Dual-Fuel Light-Duty Vehicle Manufacturing and E85 Fuel Availability, Policy Case
(percent of total)



Source: National Energy Modeling System, run IRES2525.D060607A.

The incremental cost of adding an E85 dispenser at a new retail fuel facility is negligible in comparison with the cost of adding a new gasoline dispenser. If the conversion to E85 from an existing gasoline dispenser is made during the regularly scheduled cycle for gasoline tank and equipment maintenance and cleaning, the incremental cost of conversion to the E85 fuel dispensing capability ranges between a few percent and 50 percent of the cost for a conversion done outside the normal maintenance cycle.

Also not addressed in this study are the costs and implications associated with developing an ethanol distribution network capable of moving in excess of 60 billion gallons of ethanol annually. The distribution costs represented here reflect an infrastructure designed to accommodate volumes expected under typical business-as-usual projections, which are significantly lower than the volumes addressed in this study. Distribution of ethanol in all cases is accomplished via truck, rail, and barge shipments, with costs varying by mode of travel and intra- or interregional considerations.

Depending on the mode of travel and distance shipped, ethanol distribution costs vary from 3.5 cents per gallon to 14.0 cents per gallon, excluding any additional costs that may be incurred due to additional infrastructure development requirements, congestion, new distribution patterns, or legal issues related to an expanded ethanol distribution network. Also not considered are any distribution cost *savings* that could result from the installation of dedicated ethanol pipelines.

Fuel Prices and Expenditures

The 25-percent RFS policy raises consumer prices for gasoline and diesel in 2025 by about 13 percent and 22 percent, respectively (Table 3). After 2025, the RFS percent ceases to change, reducing the upward pressure on gasoline and diesel prices. In 2030, gasoline and diesel prices in the Policy Case are about 11 percent and 17 percent higher, respectively, than in the Reference Case.

Table 3. Transportation Sector Key Indicators and Delivered Energy Consumption

	2005	2025		2030	
		Reference	Policy	Reference	Policy
Light-Duty Vehicles					
Billion Miles Traveled	2,721	3,930	3,869	4,323	4,230
Efficiency – Miles Per Gallon					
Average For New Light-Duty Vehicles	25.2	29.1	29.1	29.4	29.7
New Cars	30.0	33.5	33.8	33.9	34.5
New Light Trucks	21.8	26.1	25.7	26.6	26.5
Average, All Light-Duty Stock	19.7	21.9	21.7	22.3	22.4
New Car Sales (thousands)	8,109	8,687	9,095	8,926	9,406
New Light Truck Sales (thousands)	8,125	10,442	9,560	11,256	10,628
Highway Energy Use (quadrillion Btu)					
Total Light-Duty Vehicles	16.9	21.6	21.5	23.3	22.9
Automobiles	8.4	8.7	9.0	9.0	9.2
Light Trucks	8.5	12.9	12.4	14.2	13.7
Energy Use by Fuel (quadrillion Btu)	16.9	21.6	21.5	23.3	22.9
Motor Gasoline	16.6	20.8	15.1	22.3	16.1
Distillate Fuel Oil (Diesel)	0.3	0.7	0.1	0.9	0.1
E85	0.0	0.01	6.24	0.02	6.69
Total Transportation Consumption (quadrillion Btu)	**28.1**	**36.5**	**36.0**	**39.1**	**38.1**
Key Transportation Fuel Prices (dollars per gallon)					
Average Gasoline Price	2.32	2.16	2.44	2.21	2.45
Average Diesel Price	2.41	2.21	2.70	2.31	2.70
Average E85 Price	2.19	2.22	1.89	2.23	1.91
Transportation Energy Expenditures		**2009–2025**		**2009-2030**	
Cumulative Undiscounted Billion Dollars	NA	8,493	8,759	11,552	12,113
Discounted at 7 Percent	NA	5,121	5,232	5,968	6,162

Note: All prices are in 2005 dollars.

Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Unlike gasoline and diesel fuel prices, E85 prices in the Policy Case fall, because revenues from RFS credits reduce the price of ethanol production. E85 prices in the Policy Case are about 15 percent lower than those in the Reference Case in 2025 and 2030, despite the increased cost of ethanol production in the Policy Case.

Transportation energy expenditures in the Policy Case are about $68 billion (12 percent) higher in 2025 and $50 billion (7.7 percent) higher in 2030 than in the Reference Case. Cumulative undiscounted consumer expenditures for transportation energy between 2009 and 2025 are about $266 billion higher in the Policy Case than in the Reference Case.

End-Use Carbon Dioxide Emissions

In the Reference Case, total end-use CO_2 emissions increase from 5,945 million metric tons CO_2 equivalent in 2005 to 7,381 million metric tons in 2025 and 7,914 million metric tons in 2030 (Table 4). In the Policy Case, CO_2 emissions from the end-use sectors are significantly lower, because the average carbon intensity of the fuels used is lower. In 2025, total end-use CO_2 emissions are 13 percent (972 million metric tons) lower in the Policy Case than in the Reference Case, and in 2030 they are 14 percent (1,138 million metric tons) lower.

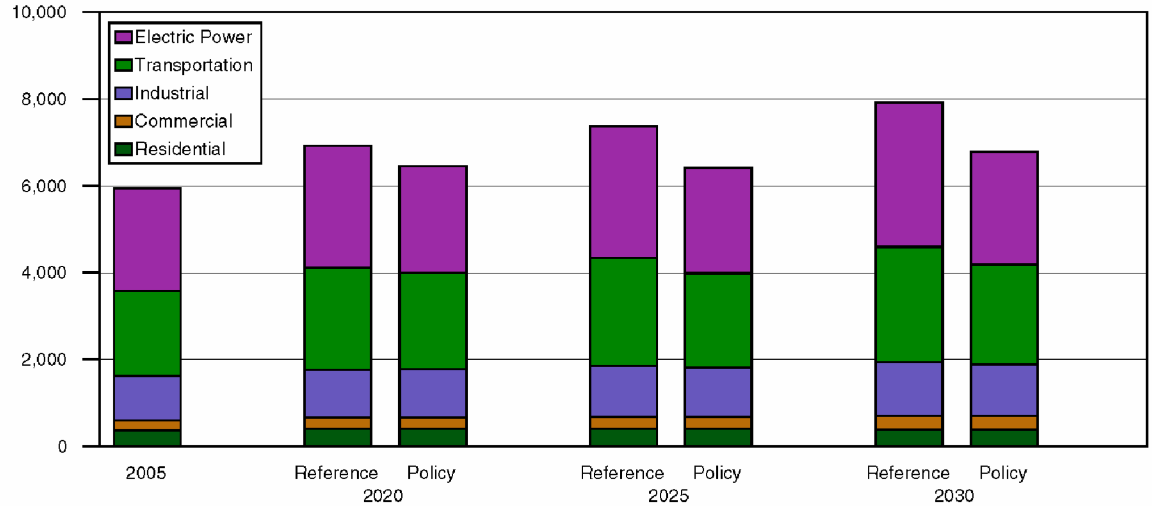
Table 4. Carbon Dioxide Emissions by End-Use Sector
(million metric tons carbon dioxide)

Sector	2005	2025		2030	
		Reference	Policy	Reference	Policy
Residential	1,254	1,531	1,304	1,614	1,360
Commercial	1,051	1,461	1,228	1,623	1,345
Industrial	1,682	1,893	1,710	2,013	1,777
Transportation	1,958	2,497	2,168	2,664	2,294
Total	**5,945**	**7,381**	**6,409**	**7,914**	**6,776**

Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

In the Reference Case, the transportation sector accounts for 33.8 percent of total CO_2 emissions in 2025, followed by the industrial sector (25.6 percent), residential sector (20.7 percent), and commercial sector (19.8 percent). CO_2 emissions from the electric power sector are assigned to each sector according to its share of electricity sales. Compared with the Reference Case, the reductions in CO_2 emissions in 2025 in the Policy Case are proportional to the change in energy consumption in the transportation sector. The transportation sector reductions account for 34 percent (329 million metric tons) of the total CO_2 reduction of 972 million metric tons in 2025 (Figure 11).

Figure 11. Carbon Dioxide Emissions by End-Use Sector, Reference and Policy Cases
(million metric tons)



Notes: Emissions associated with electricity consumption in the end-use sectors is reported under electric power.
Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

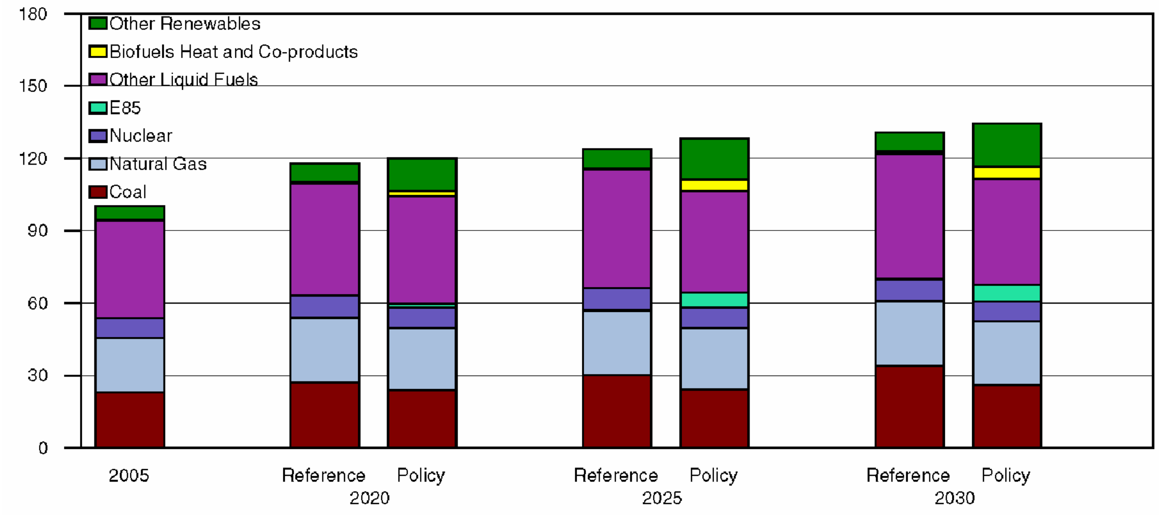
Primary Energy Impacts

Increasing the use of renewable fuels in the electricity and motor fuels sectors would lead to higher overall primary fuel use, because additional energy would be needed to produce ethanol and because of the accounting conventions used to estimate the primary resources consumed in renewable electricity generation. For example, for wind, geothermal, and solar electricity generation, primary energy use is calculated by multiplying the renewable electricity generated by an assumed standard heat rate of 10,200 Btu per kilowatthour to derive a fossil-fuel equivalent. In these cases the measure can be somewhat misleading, because increased use of primary energy is often considered a negative attribute of policy. A more meaningful measure is total consumption of nonrenewable primary energy from coal, oil, and nuclear fuels.

In the Policy Case for this analysis, total primary energy consumption from nonrenewable sources is 5.3 percent lower in 2020, 7.7 percent lower in 2025, and 8.6 percent lower in 2030 than in the Reference Case (Figure 12).

The 25-percent RPS policy leads to lower coal and, to a lesser extent, natural gas and nuclear fuel use in 2025 as generation from nonrenewable fuels is displaced by generation from renewable fuels. In the Policy Case, coal use is 3.1 quadrillion Btu (11 percent) lower in 2020, 6.1 quadrillion Btu (20 percent) lower in 2025, and 7.8 quadrillion Btu (23 percent) lower in 2030 than in the Reference Case. The change in natural gas and nuclear use is smaller than 10 percent in all years.

Figure 12. Primary Fuel Consumption, Reference and Policy Cases
(quadrillion Btu)



Note: “Other Liquid Fuels” includes all liquid fuels other than E85.
Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

The percentage of nonrenewable fuel use declines in the Policy Case with the increasing RPS and RFS percentages but not as quickly as the RPS and RFS requirements rise. In the electricity generation sector, new renewable capacity displaces more efficient coal and natural gas capacity that would have been built in the Reference Case. Because the newer capacity would have been more efficient and would have been run at higher utilization rates than the older coal and natural gas units, the RPS actually increases the amounts of coal and natural gas consumed per kilowatthour of electricity generated.

Nonrenewable liquid fuel use is also significantly lower in the Policy Case, because it is displaced by increased ethanol use in gasoline blending and E85 and increased biodiesel use in diesel fuel, including ethanol and biodiesel blends. Overall, nonrenewable liquid fuel use is 2.3 quadrillion Btu (5 percent) lower in 2020, 5.3 quadrillion Btu (11 percent) lower in 2025, and 6.0 quadrillion Btu (12 percent) lower in 2030 in the Policy Case than in the Reference Case.

In contrast, because of the increased production and use of E85 and biodiesel in the Policy Case, the amounts of biofuels used to produce heat and co-products and other renewable fuels are all significantly higher than in the Reference Case. In combination, the use of these fuels in the Policy Case is more than double that in the Reference Case in 2020 and approaches 3.5 times the Reference Case level in 2025 and 2030.

Fuel Supply Impacts

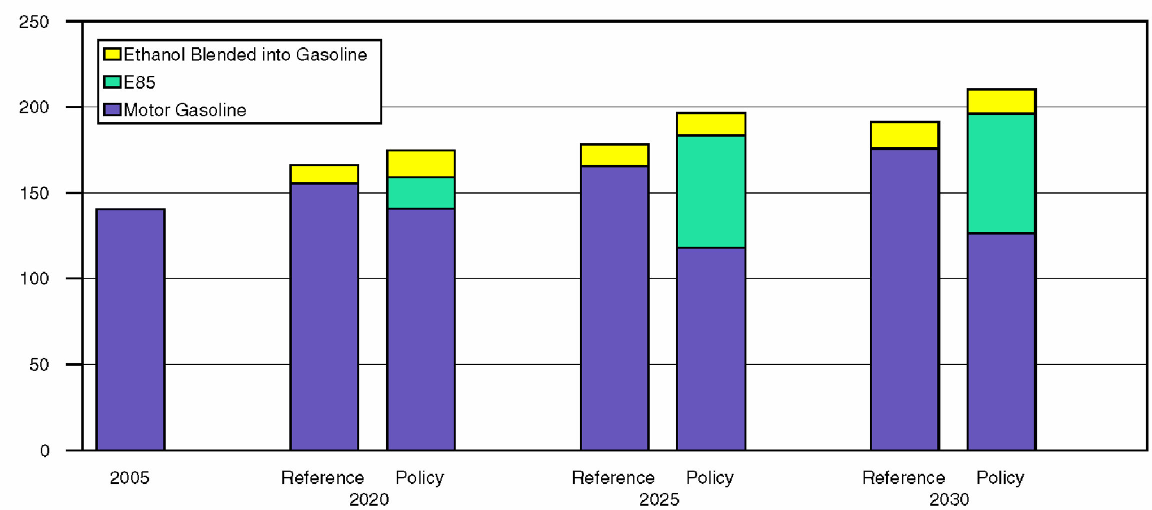
Petroleum and Renewable Fuels Impacts

The provisions of the proposed RFS require that gasoline and diesel producers must either blend and sell an increasing percentage of renewable fuels or purchase enough credits to cover their sales of gasoline and diesel fuels. For the Reference Case, this implies a need for approximately of 34 billion gallons of renewable fuel in 2020, increasing to 66 billion gallons in 2025.[14] For 2026 and each year thereafter, the renewable fuels requirement would be proportional to 25 percent of total gasoline and diesel sales, including ethanol and biodiesel blends, in that year. In 2030, the Policy Case would require approximately 70 billion gallons of biofuels to be consumed in the motor transport market.

Under the RFS proposal, suppliers of gasoline, diesel, E85, and diesel blends would be obligated to hold one biofuel credit for every 4 gallons of motor fuel sold (e.g., gasoline, E10, E85, biodiesel blends, and diesel). For this study, ethanol and biodiesel are considered to be the only renewable fuels qualified to fulfill the RFS requirement. In contrast to the existing RFS, no additional credit is assigned to either fuel, depending on its feedstock or technology.

Given the magnitude of the RFS requirement, gasoline blends containing up to 10 percent ethanol (E10) would not be sufficient to ensure compliance. Most gasoline-powered vehicles currently manufactured are warranted to operate on gasoline blends with ethanol content up to 10 percent. The use of FFVs, which can operate on much higher concentrations of ethanol—currently, up to 85 percent (E85)—would be required.[15] In 2025, the market share of E85 in the gasoline pool is projected to increase from less than 1 percent in the Reference Case to almost 30 percent in the Policy Case (Figure 13).

Figure 13. Composition of the U.S. Gasoline Pool, Reference and Policy Cases
(billion gallons)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

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[14]The quantity of motor gasoline consumed in 2025, including sales of E85, is 197 billion gallons. The amount of diesel fuel consumed in 2025, as represented by sales of ultra-low-sulfur diesel (ULSD) and biodiesel blends, is 65 billion gallons.
[15]To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for the projections.

Many new light-duty vehicles powered by diesel fuel are warranted for up to 5 percent biodiesel. The reluctance of engine manufacturers to warranty higher blends stems from concerns about the wide range of product quality currently on the market. A campaign to improve the quality of the product significantly is assumed to mitigate such concerns to the point where the number of manufacturers willing to warrant certified B20 blends (a mixture of petroleum diesel and 20 percent biodiesel) will be sufficient to absorb the volumes of biodiesel available.[16]

Tables 5 and 6 and Figure 14 summarize the major impacts of the proposed RFS on the downstream market for liquid motor fuels. Relative to the Reference Case, the RFS requirement is projected to increase the consumption of renewable fuels by 21 billion gallons in 2020 and 50 billion gallons in 2025 in the Policy Case. The increase in biofuel consumption increases the cost of gasoline in the Policy Case by 10 cents per gallon in 2020 and by 28 cents per gallon in 2025 (2005 dollars). For diesel fuel, the cost increases are 15 cents per gallon in 2020 and 49 cents per gallon in 2025. The comparatively higher impact on diesel prices results in part from the lower average renewable content of diesel fuel.[17] Each gallon of renewable fuel blended into a product lowers the number of credits needed and the price. As a result, diesel bears more of the cost of RFS compliance than motor gasoline on a per-gallon basis.

Higher relative prices in the Policy Case contribute to a reduction in transportation fuel use. In the Policy Case, liquid motor fuels consumption is approximately 480 trillion Btu (about 1.5 percent) lower than in the Reference Case in 2025 and about 940 trillion Btu (about 2.5 percent) lower in 2030.[18] The combination of displacing petroleum volumes with renewable fuels and lowering consumer demand for petroleum products reduces the consumption of imported crude oil and petroleum products by approximately 0.8 million barrels per day in 2020, 2.1 million barrels per day in 2025, and 2.4 million barrels per day in 2030. Domestic crude oil production is minimally affected in the Policy Case, but refinery gain is reduced due to reduced refining activity and natural gas liquids production falls with the reduction in natural gas production resulting primarily from the RPS. The import share of liquid fuel consumption, including ethanol imports, declines from about 60 percent in the Reference Case to about 51 percent in the Policy Case in 2025.

Despite the drop in fuel use, consumer expenditures on liquid transportation fuels increase in the Policy Case by $28 billion in 2020, $69 billion in 2025, and $51 billion (2005 dollars) in 2030 compared with the Reference Case.

The RFS credit price is $2.18 in 2025 and $2.02 per gallon in 2030 in the Policy Case.

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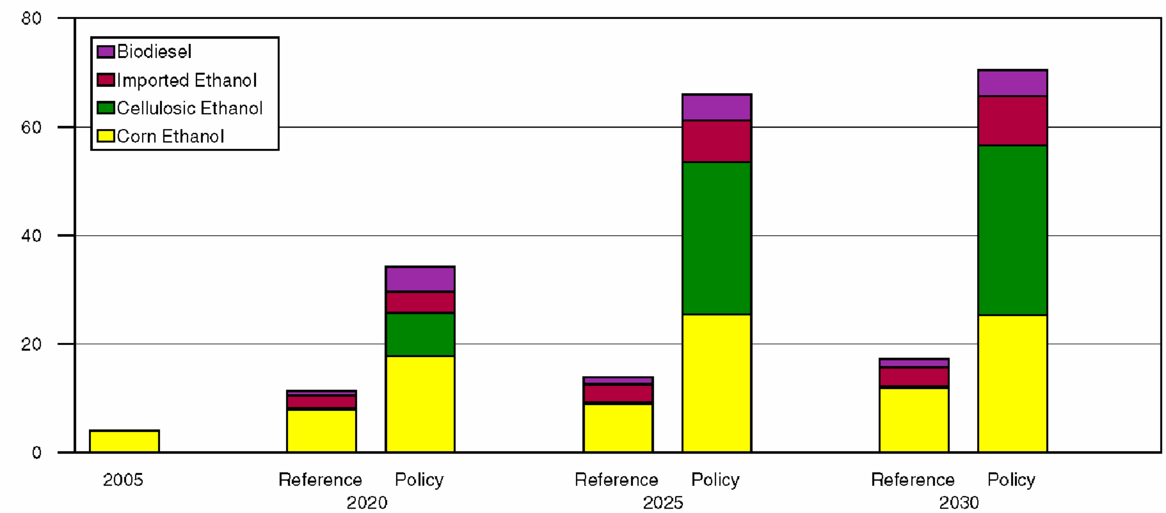
[16]Cummins (a manufacturer of on-highway truck engines with significant market share) has approved B20 from BQ-9000 certified companies. BQ-9000 is the biodiesel industry's quality control program for biodiesel producers consistently meeting American Society of Testing Materials specification D-6751.
[17]The opportunities for large-scale biodiesel production—at the scale envisioned for either corn-based or cellulosic ethanol for this policy proposal—are limited, in part because ethanol receives the same credit price per gallon as biodiesel even though biodiesel contains considerably more energy per gallon, and because ethanol is expected to be cheaper to produce at quantities exceeding 5 billion gallons per year.
[18]Because E85 has roughly 75 percent of the energy content of gasoline, energy units (rather than volume) are used in comparing fuel demand across cases.

Table 5. Liquid Fuels Supply Impacts of the Reference and Policy Cases

Supply and Disposition	2005	2025		2030	
		Reference	Policy	Reference	Policy
Supply (million barrels per day)					
Net Crude Oil Imports	10.1	12.0	11.3	12.8	11.7
Net Product Imports	2.5	2.9	1.8	3.5	2.5
Ethanol Imports	0.01	0.2	0.5	0.2	0.6
Domestic Ethanol Supply	0.3	0.6	3.5	0.8	3.7
Net Import Share of Liquid Product (percent)	60.5	59.6	51.1	61.0	52.8
Ethanol (billion gallons)					
Corn Based	3.9	9.0	25.5	12.0	25.3
Cellulose Based	0.0	0.3	28.1	0.3	31.3
Imports	0.1	3.3	7.7	3.5	9.0
Ethanol Total	**4.0**	**12.5**	**61.3**	**15.7**	**65.6**
Consumption (quadrillion Btu)					
E85	0.0	0.01	6.2	0.02	6.7
Motor Gasoline	17.0	21.3	15.5	22.7	16.6
Motor Diesel	6.0	8.6	7.7	9.6	8.2
Transportation Liquid Fuels Subtotal	27.4	35.6	35.1	38.2	37.2
All Liquid Fuels	**39.5**	**48.1**	**47.3**	**51.0**	**49.6**
Delivered Petroleum Product Prices (2005 dollars per gallon)					
E85	2.19	2.23	1.89	2.23	1.91
Ethanol Wholesale Price	1.80	1.64	2.76	1.67	2.69
Motor Gasoline	2.32	2.16	2.44	2.21	2.45
Motor Diesel	2.41	2.21	2.70	2.31	2.70
Credit Price	**NA**	**NA**	**2.18**	**NA**	**2.02**

Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Figure 14. Sources of Renewable Liquid Fuel Supply, Reference and Policy Cases
(billion gallons)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Table 6. Renewable Fuels Summary for the Reference and Policy Cases

	2005	2025 Reference	2025 Policy	2030 Reference	2030 Policy
RFS Results					
RFS Constraint (billion gallons)	3.5	9.0	66.0	9.8	70.4
Credit Price[1] (dollars per gallon)	NA	NA	2.18	NA	2.02
Ethanol (billion gallons)					
Corn Based Production	3.9	9.0	25.5	12.0	25.3
Cellulose Based Production	0.00	0.25	28.0	0.25	31.3
Imports	0.1	3.3	7.7	3.5	9.0
Total	**4.0**	**12.5**	**61.3**	**15.7**	**65.6**
Ethanol in E85 (billion gallons)	0.01	0.05	48.1	0.08	51.6
Ethanol in Gasoline Blending	4.0	12.5	13.2	15.6	14.1
Percent of Motor Gasoline Pool	2.9	7.0	31.2	8.2	31.2
Blend Percent of Motor Gasoline	2.9	6.9	9.4	8.1	9.4
Prices (2005 dollars)					
Corn Price (dollars per bushel)	2.29	3.00	6.50	3.17	6.21
CD 4 Biomass Price (dollars per million Btu)	0.94	1.51	5.02	1.51	5.12
Agricultural Impacts					
Total Corn Crop (million bushels)	11,807	14,138	14,473	14,899	15,170
Corn for Ethanol (million bushels)	1,323	3,363	9,228	4,433	9,174
Fraction of Corn Going to Ethanol	11%	24%	64%	30%	60%
Net Corn Exports (million bushels)	1,814	2,657	-1,871	2,099	-1,561
Corn Acres (million acres)	74	77	79	77	78
Corn Yield (bushels per acre)	160	183	183	194	194
Biomass Supplied (million tons)	<30	41	535	43	579

[1]All prices are in 2005 dollars.
Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Ethanol Imports

The United States recently passed Brazil to become the world’s largest producer of fuel ethanol. In the past, Brazil has emphasized ethanol production from sugar cane for domestic use. More recently, representatives of the Brazilian government have expressed interest in exporting more ethanol, with the United States considered as an important potential market.[19]

Brazil currently cultivates sugar cane on about 6 million hectares of land (1 hectare = 2.47 acres). About half of the cane is used to produce ethanol, and the other half is used to produce sugar for food use. Brazil’s ethanol production in 2004 was 4.1 billion gallons, and its total exports were 635 million gallons, including 112 million gallons exported to the United States.

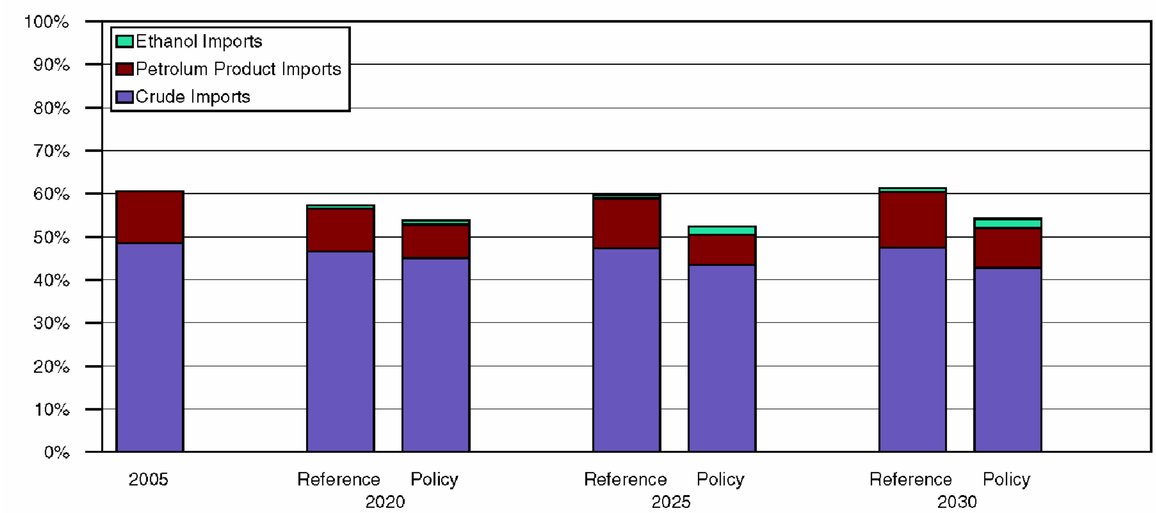
Brazil has vast potential to increase ethanol production and exports. One recent study indicated that as much as 90 million more hectares of underutilized agricultural land is

[19]“Gov. [Jeb] Bush Throws Support Behind Ethanol Initiative,” *The Miami Herald* (December 19, 2006). See http://www.mre.gov.br/portugues/noticiario/internacional/selecao_detalhe.asp?ID_RESENHA=293740&Imprime=on.

available.[20] However, the investments needed to increase production capacity to 54 billion gallons in 25 years may be substantial.[21]

Very high levels of biofuel consumption would be needed to meet the requirement of the proposed RFS policy (Figure 15), and it is possible that higher levels of ethanol imports could be a cost-effective way to meet part of the requirement. Currently, ethanol imported directly from Brazil is subject to a tariff of 54 cents (nominal) per gallon. The tariff on ethanol imports is scheduled to expire in 2010, and imports are projected to rise to 3.3 billion gallons of ethanol in the Reference Case in 2025 from approximately 0.11 billion gallons in 2005. In the Policy Case, ethanol imports total 7.7 billion gallons in 2025, or 4.5 billion gallons more than in the Reference Case (Table 6).

Figure 15. Imports as Percent of Liquid Fuel Products Supplied, Reference and Policy Cases
(percent of total supply)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Cellulosic Ethanol

No commercial plant using cellulosic feedstock to produce ethanol is in existence today. IOGEN, a Canadian biotechnology firm, estimates that the cost of such a plant would be approximately $6 per gallon of capacity annually (2005 dollars) for a plant producing 50 million gallons per year.[22] EIA estimates for its *AEO2007* reference case, and those used in this study, are based on the IOGEN estimate.

As in *AEO2007*, the capital costs in this analysis are adjusted for technological optimism (early estimates of construction costs for first-of-a-kind plants tend to be optimistic) and learning-by-doing (construction costs decline with manufacturing experience) in a manner

[20]Cambridge Energy Research Associates, *Ethanol-Powered Brazil: The Land of Green Gold?*, p. 13.
[21]University of Campinas, Sao Paulo, Brazil, *Study of the Possibilities and Impacts of the Production of Large Quantities of Ethanol with the Aim to Partially Replace Gasoline in the World.*
[22]Quoted as “installed” capital cost for the facility. See “Not Your Father’s Ethanol,” *Business Week* (February 21, 2005).

consistent with the treatment of other emerging technologies within NEMS.[23] Once the first few plants are built, with Federal incentives in this case, learning-by-doing reduces costs as experience increases.[24]

Learning-by-doing assumes that production costs fall as manufacturing experience with the technology increases. The rate of learning, however, depends on the newness and maturity of the component parts that make up the technology—the more mature the component parts, the slower the learning rate.

For cellulosic ethanol, this study assumes that two-thirds of the capital costs would be represented by mature technologies or materials, such as the power plant; only elements such as the pre-treatment and hydrolization/fermentation units are subject to very rapid learning. After the addition of 200 units (equivalent to 10 billion gallons per year capacity), the capital cost in the EIA approach is approximately 83 percent of the base cost in 2012, and 66 percent of the estimated first-of-a-kind cost. The cumulative effect of applying EIA's methodology results in an *n*th-of-a-kind plant cost for cellulosic ethanol of $5.14 per gallon per year.

A widely quoted National Energy Renewable Laboratory (NREL) study by Aden et al.[25] details an engineering study that estimates a capital cost of $3.39 per gallon per year.[26] There are several important differences between the NREL and EIA estimates. First, the NREL study is an engineering analysis of an *n*th-of-a-kind plant, which assumes that several technological and engineering hurdles will be overcome, whereas EIA's estimate is for a first-of-a-kind commercial plant. Second, the NREL study assumes a slightly larger plant (69.3 million gallons per year versus 50 million gallons per year). The economies of scale make the NREL study plant slightly less expensive. Finally, the total project economics in the NREL study were chosen to match the Department of Energy's target selling price of $1.07 per gallon (2000 dollars) to be achieved by 2010. Basing the future price on a research and development target raises the issue of uncertainty: investments in research and development cannot, statistically speaking, assure a successful outcome within a specific time frame.

EIA's *n*th-of-a-kind plant cost estimate for cellulosic ethanol of $5.14 per gallon per year is 51 percent higher than the NREL estimate for a similar but not necessarily identical plant. The EIA and NREL estimates of *n*th-of-a-kind capital costs illustrate the range of costs that may be realized, while the application of learning to the plant components illustrates the extent to which costs could decline if the technology merely evolved without further technological breakthroughs. Such breakthroughs could reduce the "footprint" of the plant

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[23]For example, http://www.eia.doe.gov/oiaf/aeo/overview/electricity.html, "technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development," and EPRI, *Technical Assessment Guide, Volume 1: Electricity Supply-1986*, pp. B-18 to B-20.

[24]See Energy Information Administration, *Electricity Market Module Documentation*, DOE/EIA-M068(2006), pp. 69-73, web site http://tonto.eia.doe.gov/FTPROOT/modeldoc/m068(2006).pdf.

[25]A. Aden, M. Ruth, K. Ibsen, J. Jechura, K. Neeves, J. Sheehan, and B. Wallace, *Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover*, NREL/TP-510-32438 (June 2002).

[26]Escalated by Chemical Engineering Plant Cost Index, from 2000 to 2005 constant dollars.

and lead to much greater cost reductions than currently projected by EIA. Such breakthroughs are not predictable, however, and assuming that they will occur would indicate a higher degree of technological progress than has been observed for other technologies.[27]

Agriculture Market Impacts

Dramatic increases in domestic production of corn ethanol would be needed to meet the renewable fuels requirement in the Policy Case. Corn ethanol production reaches 25 billion gallons in 2025 in the Policy Case, and U.S. corn production is projected to be insufficient to meet the total demand for corn at such high levels of ethanol production.

Historically, the United States has been a large exporter of corn, and in the absence of new policy it is projected to continue exporting corn. But assuming that corn and cellulose would be the only sources of ethanol, the United States would be required to import corn or corn products to meet demand in the Policy Case. For example, U.S. corn exports total 2.7 billion bushels in 2025 in the Reference Case, whereas corn *imports* total 1.9 billion bushels in 2025 in the Policy Case (Table 6).

It is likely, however, that U.S. agriculture and biofuels markets would adjust to higher corn prices in ways that would eliminate the need for corn imports. For instance, feedstocks previously regarded as uneconomical might be used to produce ethanol or biodiesel (in the United States or elsewhere) to meet the requirement. Furthermore, the projections assume that corn yields would continue to increase at historical rates, from 151 bushels per acre in 2006 to 183 bushels per acre in 2025. Genetic improvements to corn plants, however, may allow quicker yield growth or higher sugar/starch content. Any of these developments, which may be triggered by the relatively higher price of corn, would lessen the need for corn imports in the Policy Case. Alternatively, any corn imports could be in the form of a wide range of finished and intermediate products that contain corn.

EIA models domestic ethanol production from corn and cellulosic biomass and Brazilian ethanol production from sugar cane. It is possible that very high corn prices could cause U.S. ethanol producers to turn to other starchy or sugary crops that EIA has not modeled, such as sugar cane, higher-starch corn, sorghum, wheat, barley, sugar beets, potatoes, or cassava. Ethanol producers might also choose corn wet-mill technology over corn dry-mill technology to produce ethanol. Wet mills produce corn oil, corn gluten meal, and corn gluten feed as co-products. The output of these products per bushel of corn is more valuable than DDGS from a dry mill, but wet mills require higher capital expenditures.

New corn ethanol plants are assumed to be the dry-mill type, producing DDGS as a co-product. DDGS can be used as an animal feed supplement, but there are limits on its use, depending on the type of animal. At current levels of corn ethanol production, DDGS is assumed to sell for the price of corn on a weight basis. This analysis assumes that the DDGS value starts to fall in relation to corn at a production level of 18 billion gallons. If the value of DDGS falls sufficiently, it is assumed that the DDGS would be burned for process

[27] A. McDonal and L. Scharattenhozer, "Learning Rates for Energy Technologies," *Energy Policy*, Vol. 29, No. 4 (2001), pp. 255-261.

energy at the ethanol plant. In 2025, 78 million tons of DDGS is projected to be produced in the Policy Case, with 15 million tons used for process energy.

There are many uncertainties about the agriculture market impacts of high levels of biofuels demand. The corn price in 2025 is projected to rise from $3.00 per bushel (2005 dollars) in the Reference Case to $6.50 per bushel in the Policy Case (Table 6). The higher corn prices would cause prices for other commodities to rise, and the increases would be reflected in food prices. In the short term, higher food prices would impose hardships on developing nations. In the longer term, however, farmers in the developing world could benefit from the increased demand for agricultural products, which would lead to more investment and more farm employment. Some investments could enable current subsistence farmers to market their surplus output.

EIA models domestic biodiesel production from soybean, cottonseed, canola (edible rapeseed), sunflower oils, yellow grease, and animal fats. European biodiesel producers prefer industrial rapeseed oil for raw material, because it yields biodiesel with better cetane and cold flow properties than soybean oil biodiesel. Industrial rapeseed is not edible, however, which limits it potential market and marketability by farmers. U.S. farmers want as many markets for their crop as possible to enhance profits at minimum risk, and they tend to resist cultivation of crops specialized to one use. Farmers like the fact that conventional corn and soybeans can be sold for food or industrial use.

The proposed RFS policy probably would result in added incentives for farmers to grow specialized biofuels crops beyond those incorporated in current modeling structures. It is possible that U.S. agriculture in the future will be better optimized for biofuels production. Finally, EIA also does not model biodiesel production from algae or jatrohpa, both of which promise higher yields of oil per acre of land than soybeans.

Meeting the requirements of the proposed Policy could be more costly than indicated in this analysis if other nations also increased their requirements for renewable motor fuels. Japan, for example, recently mandated ethanol-blended gasoline, and the European Union has set a target of 5.75 percent biofuels in fuels for light-duty vehicles. The proposed Policy would also be affected by the choices of other nations that produce and export biofuels. Brazil, the largest exporter of ethanol, and Indonesia and Malaysia, major exporters of palm oil that can be used to make biodiesel, might choose to use more of their production domestically to displace fossil fuels.

Natural Gas Supply

In the Policy Case, natural gas consumption declines in the electric power sector as natural gas generation is displaced by renewable energy sources (Table 7). In the industrial sector, natural gas consumption increases in the Policy Case, as more natural gas is used in the production of corn-based ethanol. Natural gas consumed in petroleum refining is included in the industrial natural gas consumption figures shown in Table 7.

Table 7. Natural Gas Consumption by Sector, 2030
(trillion cubic feet)

Consumption Category	Reference Case	Policy Case
Residential and Commercial	9.6	9.6
Electric Power	5.9	5.0
Industrial	8.6	9.1
Petroleum Refining	1.2	1.7
Other Consumption	2.0	1.9
Total U.S. Consumption	**26.1**	**25.6**

Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

The increase in natural gas consumption for corn-based ethanol production in the Policy Case partially offsets the decline in natural gas consumption for electric power generation. As a result, total natural gas consumption and supply are projected to be only slightly (0.5 trillion cubic feet) lower in the Policy Case than in the Reference Case (Tables 7 and 8).

Table 8. Natural Gas Supply by Source, 2030
(trillion cubic feet)

Supply Category	Reference Case	Policy Case
U.S. Natural Gas Production	20.4	20.0
Net Pipeline Imports	0.9	0.9
Net LNG Imports	4.6	4.5
Supplemental Supply	0.1	0.1
Total Natural Gas Supply	**26.0**	**25.5**

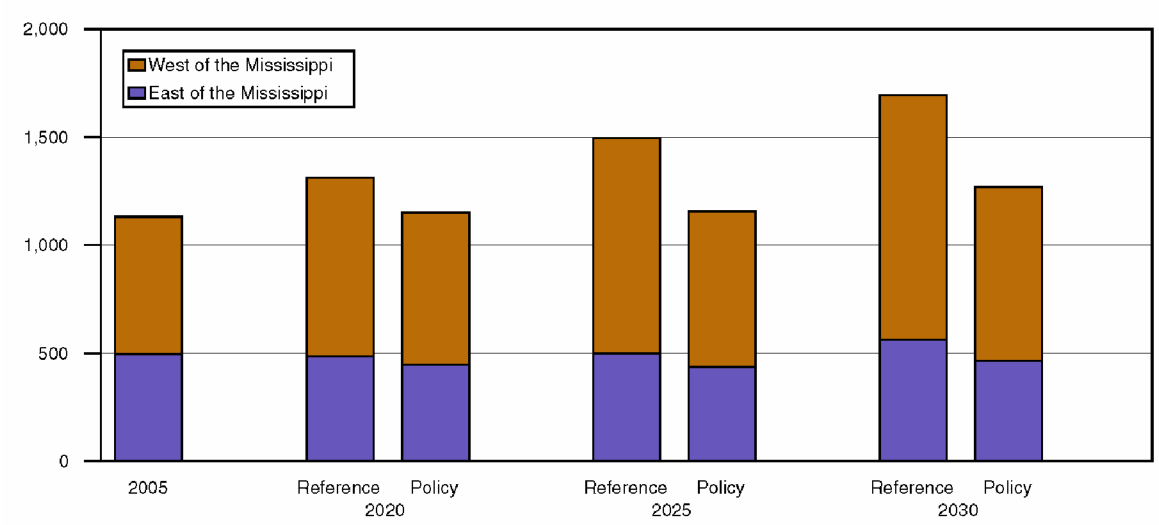
Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Coal Supply

Total coal production in the Policy Case is projected to be 23 percent (340 million tons) lower in 2025 and 25 percent (426 million tons) lower in 2030 than in the Reference Case (Figure 16). The impacts fall more heavily on coal production west of the Mississippi River, which meets most of the incremental demand for coal in the Reference Case. While the RFS also affects coal markets to some extent, the RPS for the electricity sector is the dominant influence that drives the shift away from coal in the Policy Case.

The displacement of coal-fired electricity generation by renewable generation accounts for most of the reduction in coal consumption in the Policy Case relative to the Reference Case, and much of the remaining decline is attributable to decreased production of coal-based synthetic liquids. In 2025, coal-fired generation is 691 billion kilowatthours lower in the Policy Case than in the Reference Case, equal to 73 percent of the increase in renewable generation in 2025. In 2030, the decline in coal-fired generation in the Policy Case is even larger, amounting to 938 billion kilowatthours—equal to 93 percent of the increase in renewable generation in 2030 (see Table 2).

Figure 16. Coal Production by Region, Reference and Policy Cases
(million short tons)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Reduced output of coal-based synthetic liquids in the Policy Case results from lower demand for diesel and other petroleum products and a lower selling price for the excess electricity generated at CTL plants. Relative to the Reference Case, coal consumption at CTL plants in the Policy Case is 50 million tons lower in 2025 and 61 million tons lower in 2030.

Economic Impacts

In the Policy Case, higher energy and food prices are projected to reduce economic activity (Table 9). Achieving 25-percent penetration of renewable fuels in both electricity generation and motor transportation leads to higher energy prices as consumers substitute more expensive renewable fuels for less expensive fossil fuels. Higher renewable fuel demand, in turn, increases the cost of key inputs and results in higher electricity and transportation prices.

Impacts on Energy and Aggregate Prices

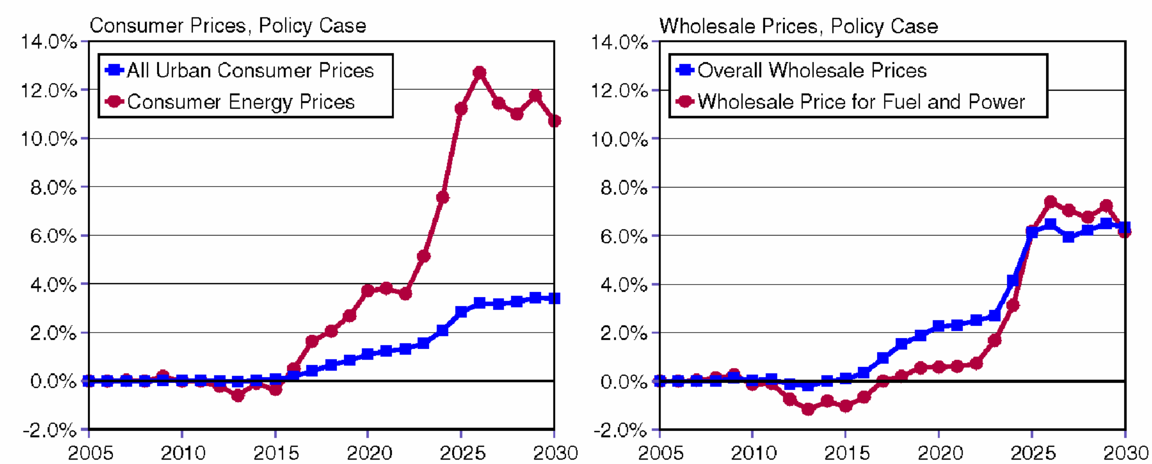
Consumer energy prices in the Policy Case rise steadily for the first 10 years of the projection, to 13.0 percent above prices in the Reference Case—roughly one-quarter of the increase in overall consumer prices. The peak consumer price inflation occurs in 2025, when the renewable standards are met, then starts to subside. The inflation rate (year-to-year change in consumer prices) reaches 12.7 percent for consumer energy prices and 3.0 percent for overall consumer prices in 2025. As energy prices begin to recede, overall consumer prices stabilize to approximately 3.0 percent above Reference Case levels. Wholesale prices show similar patterns: peaking in 2025, then starting to stabilize at higher levels after 2025 (Figure 17).

Table 9. Economic Impacts, Policy Case

	2006	2020		2025		2030	
		Reference	Policy	Reference	Policy	Reference	Policy
Components of GDP (billion 2000 dollars)							
GDP	**11,415**	**17,082**	**17,060**	**19,670**	**19,595**	**22,496**	**22,427**
Consumption	8,083	12,010	11,989	13,732	13,693	15,590	15,584
Investment	1,966	3,034	3,029	3,772	3,762	4,737	4,797
Government	1,997	2,396	2,399	2,542	2,549	2,710	2,723
Exports	1,299	3,588	3,571	4,902	4,836	6,586	6,439
Imports	1,928	3,768	3,755	4,966	4,960	6,654	6,715
Aggregate Prices in the Economy							
WPI – Fuel & Power (1982 = 1.0)	1.72	1.83	1.84	2.12	2.25	2.42	2.57
CPI – Energy (1982/84 = 1.0)	2.03	2.17	2.25	2.51	2.79	2.85	3.15
CPI – All Urban (1982/84 = 1.0)	2.02	2.60	2.63	2.90	2.98	3.23	3.34
WPI – All commodities (1982 = 1.0)	1.66	1.81	1.85	1.94	2.06	2.06	2.19
Inflation Rate, Unemployment Rate and Federal Funds Rate							
Inflation	3.56	1.83	2.09	2.26	3.02	2.27	2.24
Unemployment Rate	4.72	4.46	4.56	4.54	4.70	4.71	4.90
Federal Funds Rate	5.01	5.04	5.22	5.10	5.52	5.19	5.25
Industrial Sector (billion 2000 dollars)							
Total Industrial	5,899	7,792	7,703	8,590	8,344	9,502	9,188
Non-Manufacturing	1,557	1,847	1,802	1,937	1,859	2,022	1,955
Manufacturing	4,342	5,945	5,901	6,654	6,485	7,480	7,233
Energy-Intensive	1,186	1,431	1,416	4,528	1,470	1,635	1,565
Non-Energy-Intensive	3,156	4,514	4,484	5,126	5,015	5,845	5,669
Disposable Income	**8,279**	**13,007**	**12,989**	**15,171**	**15,137**	**17,530**	**17,529**
Disposable Income Per Capita	**27,632**	**38,582**	**38,529**	**43,248**	**43,153**	**48,036**	**48,032**

Note: WPI = Wholesale Price Index; CPI = Consumer Price Index.
Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Figure 17. Consumer and Producer Prices, Policy Case
(percent change from Reference Case)



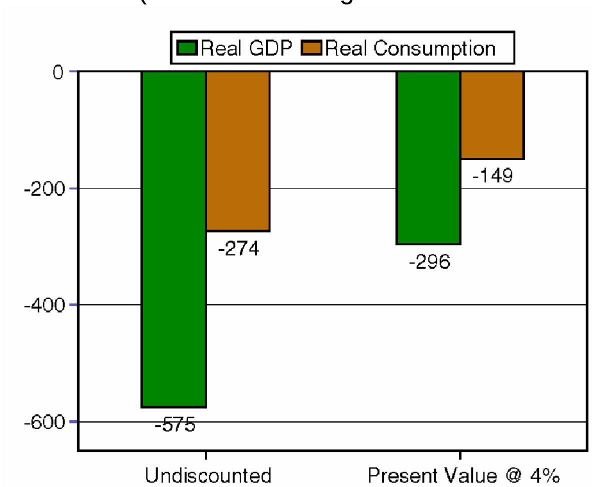
Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

GDP and Consumption Impacts

In general, higher delivered energy prices relative to a baseline reduce real output for the economy, energy consumption, and, indirectly, real consumer spending for other goods and services due to lower purchasing power. In the Policy Case, higher energy prices result in lower aggregate demand for goods and services and lower real GDP relative to the Reference Case (Figure 18). In the Policy Case, total discounted GDP losses[28] over the 2009 to 2030 time period are $296 billion (-0.12 percent) relative to the Reference Case. After energy prices peak in 2025, both real GDP and consumption begin to return to baseline levels.

Real GDP is a measure of what the economy produces; however, consumers ultimately are interested in their purchases of goods and services, or "consumption." GDP and consumption impacts of a proposed policy can differ if the policy leads to changes in the level and shares of the GDP: consumption, investment, government expenditures, and net exports. In the Policy Case, cumulative discounted consumption losses relative to the Reference Case are $149 billion (-0.09 percent). Consumption impacts, like GDP impacts, generally grow over time; however, as energy price increases subside, consumption begins to return to the respective reference cases. On an undiscounted basis, GDP and consumption losses are much larger[29] (Figure 18).

Figure 18. Real GDP and Consumption Impacts, Policy Case
(cumulative change from Reference Case, billion 2000 dollars)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

Industry and Employment Impacts

As energy prices increase, the energy-intensive sectors, including food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum, show greater losses than

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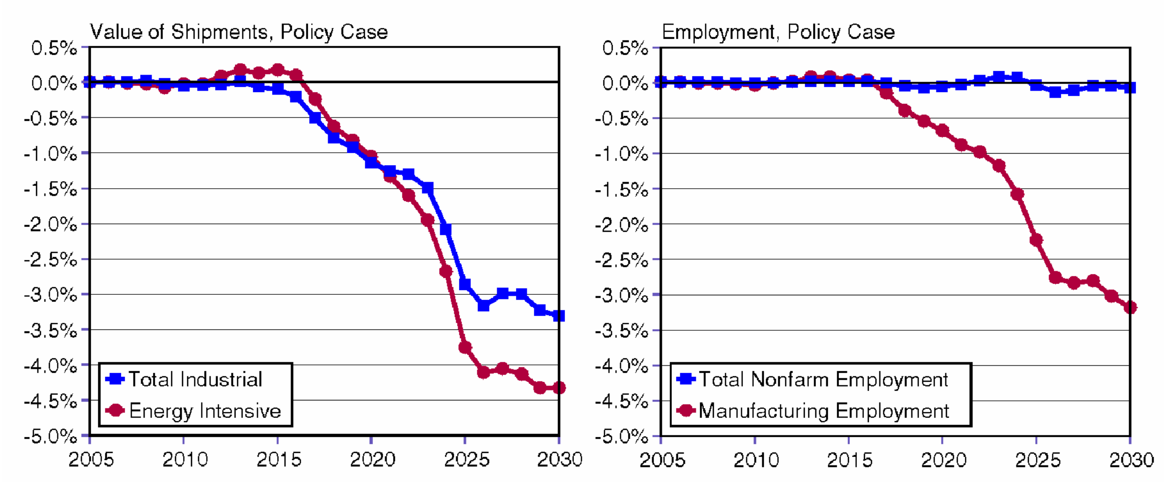
[28]The discount rate used to compute macroeconomic losses in GDP and consumption losses is 4 percent.
[29]Using the economic principle of discounting and the time value of money tends to weigh losses at the beginning of a period more than equal losses at the end of a period. For example, a dollar loss in 2030 is valued at about $0.45 in 2010 when discounted at 4 percent.

the rest of the industrial sectors, reaching 4.3 percent below the Reference Case in 2030 in the main Policy Case. Figure 19 shows output losses for the industrial sector as a whole and for the energy-intensive industries in the Policy Case. The industrial value of shipments in the energy-intensive industries is down by 4.3 percent relative to the baseline in 2030, as higher inflation and lower demand impact industrial activity. Total non-farm employment is down by 0.1 percent in 2030, as a result of lower industrial activity.

Figure 19. Industrial Impacts, Policy Case
(percent change from Reference Case)



Source: National Energy Modeling System, runs IBASE.D060607A and IRES2525.D060607A.

4. Alternative Cases

Chapter 2 described some of the analytic issues and uncertainties associated with an analysis of the proposed Policy—national implementation of a 25-percent RPS and a 25-percent RFS by 2025. Chapter 3 summarized EIA's analysis of the expected consequences of the Policy, using a Reference Case based on assumptions close to those of the *AEO2007* reference case. This chapter describes analyses estimating the likely impacts of the same Policy in alternative cases, based on different assumptions about key uncertainties in the Reference Case.

Assessment of the consequences of any potential policy or proposed legislation requires the selection of a reference case against which impacts are to be measured; however, the reference case chosen will inevitably include a variety of uncertainties, including most importantly the future path of national economic growth, energy prices, and the development and adoption of new technologies. Any change in reference case assumptions about the specific resolution of such uncertainties in a projection represents, in effect, a potential alternative reference case or "view of the world." For example, the high and low economic growth cases and the high and low price cases in *AEO2007* represent such potential alternative reference cases or outlooks.

For this analysis, EIA chose three groups of key uncertainties to be examined, first by changing assumptions from those in the Reference Case—creating three "alternative reference cases"—and then by adding the policy assumptions to each of the alternative cases.[30] The resulting six cases, which were summarized briefly in Chapter 1 (see Table 1), are as follows:[31]

- **High Price Case:** The High Price Case, modified from the *AEO2007* high price case to incorporate the same changes in assumptions that were made in the Reference Case for this study, uses more pessimistic assumptions for worldwide crude oil and natural gas resources. In this alternative reference case, world light, sweet crude oil prices in 2030 are about 70 percent higher than projected in the Reference Case.

- **High Price Policy Case:** Combines the High Price Case with model changes required to meet the Policy assumptions.

- **Low-Cost Ethanol Imports Case:** This alternative reference case incorporates the same changes in assumptions that were made in the Reference Case for this study but

[30]Typically, EIA tries to select pairs of alternative cases for its analyses that represent both more pessimistic and more optimistic assumptions about how key uncertainties will be resolved. In this analysis that was not possible, primarily because assumptions opposite to those used for the alternative cases described in this chapter—low price path for liquid fuels and natural gas, reduced availability and higher prices for ethanol imports, and slower rates for the development and adoption of renewable energy technologies (including reduced availability of biomass supplies)—would raise the cost of the policy substantially and, in all probability, make it outright impossible to achieve in some cases.
[31]The High Price Case was specifically requested by Senator Inhofe. The Low-Cost Ethanol Imports Case and High Renewable Technology Case were added by EIA to demonstrate the impacts of two other key groups of parameters.

replaces the Reference Case ethanol import supply curves with more optimistic supply curves.[32]

- **Low-Cost Ethanol Imports Policy Case:** Combines the Low-Cost Ethanol Imports Case with the Policy assumptions.

- **High Renewable Technology Case:** This alternative reference case, which is also referred to as the High Technology Case, incorporates the same changes in assumptions that were made in the Reference Case for this study and in addition uses assumptions for advanced renewable generation technologies and cellulosic ethanol production from the *AEO2007* high renewables case, *and* a much larger biomass supply (see Appendix B, Figure B1).

- **High Technology Policy Case:** Combines the High Technology Case with the Policy assumptions.

Measuring and Interpreting the Relative Impacts of the Policy

In this chapter, each of the three alternative reference cases has an associated policy case. Each alternative reference case (without the Policy assumptions) represents an alternative outlook for the U.S. energy economy, which in turn ultimately determines the magnitude of the energy and economic costs *when the proposed Policy is added to it.* In comparing the impacts of the Policy on the alternative reference cases, the appropriate comparison is between the *paired* reference and associated policy cases because they represent the same basic outlook for everything except the Policy. Comparisons between one reference case and the policy case for a *different* reference case with the Policy imposed are generally inappropriate. For example, comparison of gasoline prices in the Reference Case described in Chapter 3 with gasoline prices in the High Price Policy Case would be inappropriate because it would overstate the costs of the Policy. Similarly, comparison of gasoline prices in the Reference Case with gasoline prices in the High Technology Policy Case would also understate the costs of the Policy, unless there is a strong basis for claiming that the more favorable technology menu in the High Technology Policy Case is available only as a direct result of the Policy.

Absent a direct link between the scenario assumptions and the Policy examined in this report, the appropriate measure of the effects of the Policy under different sets of underlying assumptions is the *change* in a given projection (such as gasoline prices) in an alternative policy case from the same projection in the corresponding alternative reference case. The impact estimates provided in this chapter reflect this approach.

[32]While the Low-Cost Ethanol Import Case shows slightly greater ethanol imports (3.4 billion gallons in 2025) than the Reference Case (3.3 billion gallons in 2025), little else changes relative to the Reference Case. Consequently, results from the Low-Cost Ethanol Imports Case generally are omitted from the tables and figures in this chapter.

Electricity Sector Impacts

In the three alternative reference cases presented in this chapter, renewable energy is more competitive than in the main Reference Case, because the assumptions in the alternative cases either lower the cost of renewable energy or raise the cost of fossil energy. Low-cost ethanol imports or more rapid progress in the development and adoption of renewable technologies would lower the cost of renewable energy; higher oil and natural gas prices would raise the prices of the fossil fuels that compete with renewables. In each of the corresponding policy cases, the projections for RPS credit prices and the impacts on electricity prices are lower than those in the main Policy Case (Table 10).

In the Low-Cost Ethanol Imports Policy Case, the availability of low-cost ethanol imports reduces the use of domestic biomass by U.S. ethanol producers and makes more biomass available to power producers. In the High Price Policy Case, higher oil and natural gas prices reduce the incremental costs of increasing renewable fuel use in power generation, thus reducing the cost of complying with the 25-percent RPS. Similarly, in the High Technology Policy Case, more rapid improvement in the cost and performance of new renewable technologies makes those technologies more economically attractive and lowers RPS compliance costs.

RPS Credit Prices

In the main Policy Case, the RPS credit price rises sharply between 2020 and 2025 as the required renewable generation share grows to the 25-percent target (Figure 20). The RPS credit price in the Policy Case peaks at about 4.8 cents per kilowatthour in 2025 and then generally hovers between 3.8 and 4.6 cents per kilowatthour thereafter. The same general pattern is seen in the alternative policy cases, but the RPS credit prices tend to peak at a lower level in 2025 and then fall after 2025:

- In the Low-Cost Ethanol Imports Policy Case, the RPS credit price peaks at 4.3 cents per kilowatthour in 2025, then falls to a level of 2.5 to 3.0 cents per kilowatthour from 2025 to 2030. U.S. ethanol producers use less biomass in this case because of the lower-cost ethanol imports. The resulting increased availability of lower-cost biomass to power producers reduces their need for more expensive renewables after 2025.
- In the High Price Policy Case, the RPS credit price peaks at 4.6 cents per kilowatthour in 2025 and then generally hovers between 3.2 and 3.5 cents per kilowatthour between 2025 and 2030. The higher oil and natural gas prices after 2025 in the High Price Case (compared to the Reference Case) reduce the credit price that is needed to stimulate renewable technology options for complying with the 25-percent RPS.
- In the High Technology Policy case, RPS credit prices are much lower than in the Policy Case, peaking at 3.4 cents per kilowatthour in 2025 and falling to 1.3 cents per kilowatthour in 2030. More rapid improvement in renewable generation technologies, particularly the biomass generation technology, is the key factor leading to the lower RPS credit prices in this case. In fact, generation from biomass combustion in dedicated plants in the High Technology Case, without the 25-percent RPS requirement, is more than three times the projected level in the Reference Case in 2025, making the additional requirements in the High Technology Policy Case less difficult to meet.

Table 10. Summary of Electricity Sector Impacts of Alternative Policy Cases, 2025

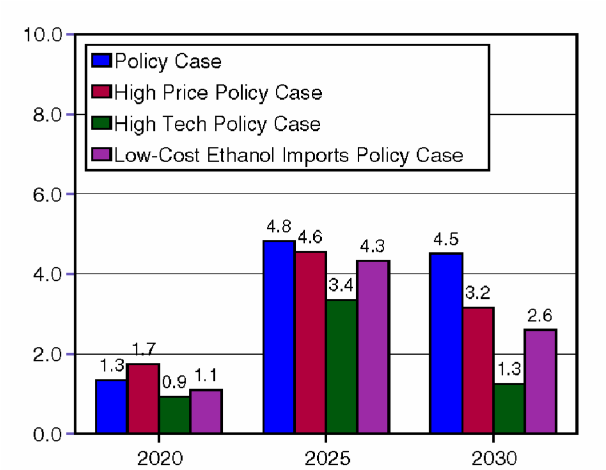
	2005	Reference	Policy	Low-Cost Ethanol Imports Policy	High Price	High Price Policy	High Tech	High Tech Policy
RPS Credit Price (2005 cents per kilowatthour)	NA	NA	4.8	4.3	NA	4.6	NA	3.4
Capacity (gigawatts)								
Coal Steam	315	406	323	323	442	353	393	325
Other Fossil Steam	121	88	81	82	75	77	89	81
Combined Cycle	177	210	196	196	194	195	208	197
Combustion Turbine/Diesel	133	135	146	140	128	140	134	142
Nuclear Power	100	112	103	103	122	103	112	103
Pumped Storage	21	21	21	21	21	21	21	21
Other	0	6	8	7	5	6	5	8
Conventional Hydropower	81	81	86	83	81	84	81	83
Geothermal	2	3	9	6	3	8	3	6
Municipal Solid Waste/Landfill Gas	4	4	6	5	4	5	4	5
Wood and Other Biomass	7	10	75	90	11	80	26	86
Solar[1]	1	2	2	2	2	2	2	2
Wind	10	18	131	98	18	123	18	107
Other Industrial Capacity[2]	18	31	33	33	27	28	31	32
Total	**988**	**1,127**	**1,220**	**1,190**	**1,134**	**1,224**	**1,127**	**1,198**
Generation (billion kilowatthours)								
Coal	2,015	2,853	2,162	2,163	3,108	2,360	2,764	2,191
Petroleum	122	105	101	100	91	87	105	101
Natural Gas	752	1,001	768	770	695	604	974	755
Nuclear Power	780	886	815	815	967	815	886	815
Pumped Storage/Other	13	8	8	8	8	8	8	8
Conventional Hydropower	265	308	328	319	308	322	309	318
Geothermal	15	22	66	47	24	59	23	44
Municipal Solid Waste/Landfill Gas	23	27	40	35	27	35	28	34
Dedicated Biomass	30	57	536	646	62	568	174	622
Biomass Co-Firing	7	67	84	110	78	88	60	89
Solar[1]	1	4	4	4	5	5	5	4
Wind	15	51	425	326	52	408	52	378
Total	**4,038**	**5,389**	**5,338**	**5,343**	**5,424**	**5,358**	**5,387**	**5,360**
Electricity Prices and Sales								
Electricity Sales (billion kilowatthours)	3,660	4,826	4,778	4,785	4,813	4,778	4,823	4,802
Retail Electricity Price (2005 cents per kWh)	8.10	7.99	8.26	8.26	8.25	8.48	7.98	8.08
Electric Sector Emissions								
Sulfur Dioxide (million short tons)	10.21	3.72	3.56	3.51	3.57	3.50	3.73	3.46
Nitrogen Oxides (million short tons)	3.60	2.25	1.93	2.03	2.19	1.92	2.24	1.99
Mercury (short tons)	51.25	16.86	16.86	17.35	15.79	15.42	16.83	16.86
Carbon Dioxide (million metric tons)	2,375	3,046	2,425	2,428	2,964	2,386	2,983	2,450
Fuel Prices (2005 dollars)								
Natural Gas Wellhead Price (dollars per mcf[3])	7.51	5.54	5.47	5.45	6.73	6.64	5.59	5.38
Coal Minemouth Price (dollars per ton)	23.34	21.83	21.34	20.83	24.14	22.37	21.63	20.76

[1]Includes solar thermal power, utility-owned photovoltaics, and distributed photovoltaics.
[2]Includes capacity in the industry sector fueled by petroleum, natural gas, or other gaseous fuels.
[3]mcf = thousand cubic feet.
Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES252HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Electricity Prices

The projected increases in electricity prices between the three alternative reference cases and their corresponding policy cases are generally smaller than the increase between the main Reference Case and the Policy Case (Figure 21). In the Policy Case, electricity prices reach 8.3 cents per kilowatthour in 2025, 0.3 cents per kilowatthour (3.3 percent) higher than in the Reference Case; and in 2030, the price difference between the Reference Case and the Policy Case grows to 0.5 cents per kilowatthour (6.2 percent). In the Low-Cost Ethanol Imports Policy Case, electricity prices are also 0.3 cents per kilowatthour (3.5 percent) higher in 2025 than in the Low-Cost Ethanol Imports Case, but the difference does not change by much after 2025. In the High Price Policy Case, electricity prices are 0.2 cents per kilowatthour (2.9 percent) higher than in the High Price Case in 2025 and 0.4 cents per kilowatthour (4.8 percent) higher in 2030.

Figure 20. RPS Credit Prices in Alternative Policy Cases
(2005 cents per kilowatthour)



Source: National Energy Modeling System, runs IRES2525.D060607A, IRES2525LCB.D060607A, IRES2525HP.D060607A, and IRES2525HT.D060607A.

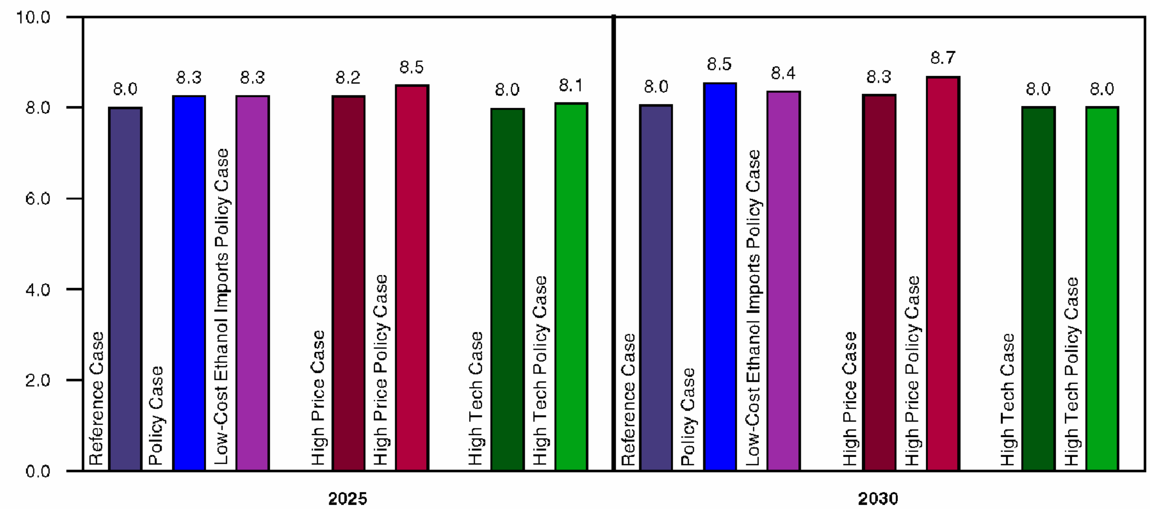
The importance of assumptions about technological progress is illustrated by their impact on electricity prices in the High Technology Policy Case: electricity prices in the High Technology Policy Case are only 0.1 cent per kilowatthour higher than prices in the High Technology Case in 2025, and there is virtually no difference in electricity prices between the two cases in 2030. In the High Technology Policy Case, new renewable technologies, particularly biomass, are competitive with nonrenewable generating technologies.

Electricity Generation by Fuel

Renewable generation in the alternative policy cases is generally similar to that in the main Policy Case (Figure 22). In all the alternative policy cases, there are very large increases in biomass and wind generation and smaller increases in geothermal and conventional hydroelectric generation, relative to the corresponding reference cases. The competition between biomass and wind to supply the generation needed to comply with the 25-percent

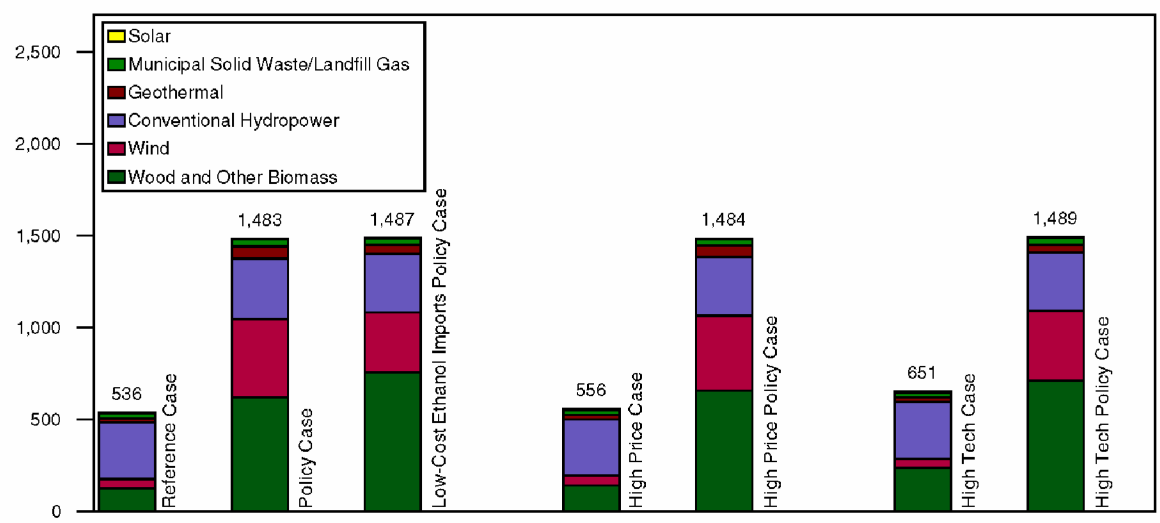
RPS does vary slightly among the alternative policy cases. In the Low-Cost Ethanol Imports Policy Case, where lower cost biomass is available to the power sector, there are larger increases in biomass electricity generation than are projected in the main Policy Case relative to the Reference Case.

Figure 21. Electricity Prices in Alternative Policy Cases, 2025 and 2030
(cents per kilowatthour)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IRES2525LCB.D060607A, IHIPRICE.D060607A, and IRES2525HP.D060607A.

Figure 22. Renewable Generation in 2025 in Alternative Cases
(billion kilowatthours)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IRES2525LCB.D060607A, IHIPRICE.D060607A, and IRES2525HP.D060607A.

Transportation Sector Impacts

Demand for transportation services is responsive to changes in fuel prices; however, the projected impacts on travel and fuel economy in the policy cases relative to their respective reference cases are minimal, because there are only minor fuel price changes between the reference cases and the associated policy cases. Transportation fuel prices vary the least between the High Price Case and High Price Policy Case and between the High Technology Case and the High Technology Policy Case (Table 11). As a result, travel demand and fuel economy show only marginal impacts, and the change in total transportation energy consumption in 2025 varies by only about 0.5 percent, across the paired reference and policy cases.

Table 11. Transportation Sector Key Indicators and Delivered Energy Consumption, 2025

	2005	Reference	Policy	High Price	High Price Policy	High Tech	High Tech Policy
Light-Duty Vehicles (LDVs)							
Billion Miles Traveled	2,721	3,930	3,869	3,664	3,641	3,935	3,909
Efficiency (miles per gallon)							
Average for New LDVs	25.2	29.1	29.1	31.6	31.0	29.0	28.8
New Cars	30.0	33.5	33.8	35.8	35.7	33.5	33.6
New Light Trucks	21.8	26.1	25.7	27.9	26.9	26.1	25.6
Average: All LDV Stock	19.7	21.9	21.7	23.1	22.9	21.7	21.6
New Car Sales (thousands)	8,109	8,687	9,095	10,255	10,127	8,631	8,815
New Light Truck Sales (thousands)	8,789	11,266	10,364	9,626	9,408	11,336	10,880
Highway Energy Use (quadrillion Btu)							
All LDVs	16.9	21.6	21.5	18.9	19.4	21.7	21.7
Automobiles	8.4	8.7	9.0	9.0	9.0	8.7	9.0
Light Trucks	8.5	12.9	12.5	9.9	10.3	12.9	12.7
Energy Use by Fuel (quadrillion Btu)	**16.9**	**21.6**	**21.5**	**18.9**	**19.4**	**21.7**	**21.7**
Motor Gasoline	16.6	20.8	14.4	17.9	13.4	20.9	15.3
Distillate Fuel Oil (Diesel)	0.3	0.7	0.1	0.8	0.1	0.7	0.1
E85	0.0	0.0	6.2	0.0	5.8	0.0	6.3
Total Transportation Energy Demand (quadrillion Btu)	**28.1**	**36.5**	**36.0**	**33.3**	**33.5**	**36.6**	**36.4**
Key Transportation Fuel Prices (dollars per gallon)							
Average Gasoline Price	2.32	2.16	2.44	3.06	3.20	2.12	2.26
Average Diesel Price	2.41	2.21	2.70	2.96	3.27	2.22	2.49
Average E85 Price	2.19	2.22	1.89	2.51	2.49	2.15	1.74
Transportation Energy Expenditures, 2009-2025							
Cumulative Undiscounted Billion Dollars	NA	8,493	8,759	10,773	10,924	8,482	8,616
Discounted at 7 Percent	NA	5,121	5,232	6,396	6,462	5,117	5,175

Note: All prices are shown in 2005 dollars.
Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES252HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Because renewable fuels are more competitive in the High Price Case and the High Technology Case than in the Reference Case, the RFS credit price is highest in the Policy Case (Table 12). Consequently, in the Policy Case, gasoline prices in 2025 are 13 percent higher and diesel prices are 22 percent higher than projected in the Reference Case, whereas in the High Price Policy Case gasoline and diesel prices in 2025 are 5 percent and 10 percent higher, respectively, than in the High Price Case, and in the High Technology Case gasoline and diesel prices in 2025 are 7 percent and 12 percent higher, respectively, than projected in the High Technology Case. Unlike gasoline and diesel fuel prices, E85 prices are lower in the policy cases than in the corresponding reference cases, because revenues from the credits are assumed to be used to reduce the cost of ethanol production.

Because the Policy Case has the highest RFS credit prices and the largest relative increases in fuel prices, it also has the largest increase in transportation energy expenditures. Compared with the Reference Case, transportation energy expenditures in 2025 are $68 billion (about 12 percent) higher in the Policy Case. Compared with the High Price Case, transportation energy expenditures in 2025 are $43.1 billion (about 6 percent) higher in the High Price Policy Case. And compared with the High Technology Case, transportation energy expenditures in 2025 are $35 billion (about 6 percent) higher in the High Technology Policy Case. From 2009 to 2025, cumulative undiscounted transportation energy expenditures by consumers are $266 billion higher in the Policy Case than in the Reference Case, $151 billion higher in the High Price Policy Case than in the High Price Case, and $132 billion higher in the High Technology Policy Case than in the High Technology Case—again illustrating that the starting point (reference case) and the pace of technological progress can have significant impacts in determining the projected effects of policy changes on energy expenditures.

Table 12. Liquid Fuels Supply Impacts in Alternative Policy Cases, 2025

	2005	Reference	Policy	High Price	High Price Policy	High Tech	High Tech Policy
Supply Balance (million barrels per day)							
Net Crude Oil Imports	10.0	12.0	11.3	9.8	9.5	12.0	11.4
Net Product Imports	2.5	2.9	1.8	1.7	1.1	2.8	1.7
Ethanol Imports	0.01	0.2	0.5	0.3	0.5	0.2	0.4
Domestic Ethanol Supply	0.3	0.6	3.5	0.8	3.2	0.8	3.7
Net Import Share of Liquids	60.5	59.6	51.1	49.6	44.2	59.0	50.9
Ethanol (billion gallons)							
Corn-Based	3.9	9.0	25.6	11.9	24.1	8.7	18.9
Cellulosic	0.00	0.25	28.1	0.2	24.6	4.0	38.0
Imports	0.1	3.3	7.7	2.9	7.5	3.0	5.3
Total	**4.0**	**12.5**	**61.3**	**15.1**	**56.2**	**15.8**	**62.2**
Consumption (quadrillion Btu)							
E85	0.00	0.01	6.2	0.02	5.8	0.01	6.3
Motor Gasoline	17.0	21.3	15.5	18.3	13.8	21.3	15.7
Transportation Liquid Fuels	27.4	35.6	35.1	32.4	32.6	35.6	35.5
All Liquid Fuels	39.5	48.1	47.3	44.3	44.2	48.1	47.8
Delivered Liquid Fuel Product Prices (2005 dollars per gallon)							
E85	2.19	2.22	1.89	2.51	2.49	2.15	1.74
Ethanol Wholesale Price	1.80	1.64	2.76	1.68	2.73	158	2.02
Motor Gasoline	2.32	2.16	2.44	3.06	3.20	2.12	2.26
RFS Credit Price	NA	NA	2.18	NA	1.46	NA	1.34
Total Energy Expenditures (billion 2005 dollars)	**907**	**1,236**	**1,317**	**1,460**	**1,513**	**1,231**	**1,269**

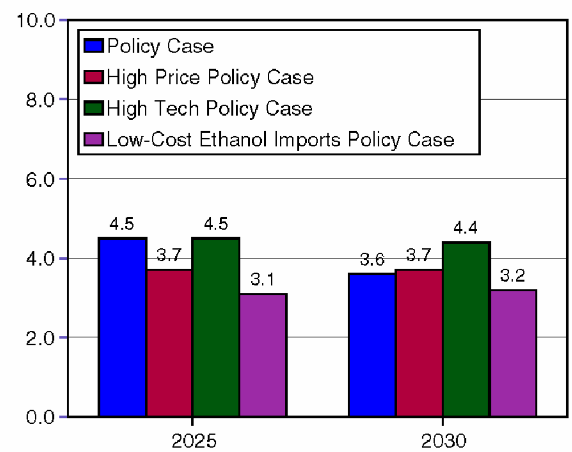
Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES252HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Primary Energy Consumption

Differences in primary energy consumption between the respective reference and policy cases are similar across the cases (Figure 23). The largest difference is between the High Technology Case and the High Technology Policy Case, where industrial sector use of biofuels heat and co-products in 2030 is 4.8 quadrillion Btu higher in the High Technology Policy Case than in the High Technology Case because of the lower costs and higher availability of biomass supplies compared to the other reference and policy cases.

Primary energy consumption in 2025 increases in all the policy cases relative to their respective reference cases, by between 3.0 and 4.5 quadrillion Btu, because coal- and natural-gas-fired generating capacity is replaced by renewable capacity to meet the policy mandates.[33] With the large buildup of renewable generation capacity, more efficient generation technologies using natural gas and coal are not added, and the average efficiency of all fossil-fired generation is reduced. On the other hand, industrial natural gas consumption increases as more ethanol production facilities begin operating.

Figure 23. Change in Primary Energy Consumption Across the Cases, 2025 and 2030
(quadrillion Btu)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES252HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Fuel Supplies

Fuel supply projections from the Reference Case, High Price Case, and High Technology Case are summarized and compared with projections from the corresponding policy cases in Table 12 (for liquid fuels) and Table 13 (for renewable fuels). As noted earlier, the starting point (assumptions) for each case matters greatly. That is, the assumptions for the different reference cases, without the policy requirements, determine the magnitude of the energy and economic impacts when the policy requirements are added.

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[33]A portion of the projected increase in primary energy consumption is due to the accounting framework used to translate wind, geothermal, solar energy used for electricity generation to primary resource equivalents. The accounting framework equates a kilowatthour of generated electricity to primary energy by multiplying by a constant but somewhat arbitrary heat rate that is close to the fossil fuel generation system average.

Table 13. Renewable Fuels Summary for the Reference and Policy Cases, 2025

	2005	Reference	Policy	High Price	High Price Policy	High Tech	High Tech Policy
RFS Results							
RFS Constraint (billion gallons)	3.5	9.0	66.0	8.4	61.0	9.0	66.9
RFS Credit Price (2005 dollars per gallon)	NA	NA	2.18	NA	1.46	NA	1.34
Ethanol (billion gallons)							
Corn-Based	3.9	9.0	25.5	11.9	24.1	8.7	18.9
Cellulosic	0.00	0.25	28.0	0.25	24.6	4.0	38.0
Imports	0.1	3.3	7.7	2.9	7.5	3.0	5.3
Total	4.0	12.5	61.3	15.1	56.2	15.8	62.2
Ethanol Used in E85	0.01	0.05	48.1	0.1	44.4	0.1	48.9
Ethanol Used in Gasoline Blending	4.0	12.5	13.2	15.0	11.9	15.7	13.3
Ethanol Percent of Motor Gasoline Pool	2.9	7.0	31.2	9.7	31.7	8.8	31.2
Blend Percent of Motor Gasoline Pool	2.9	6.9	9.4	9.5	9.6	8.6	9.4
Prices (2005 dollars)							
Corn Price (2005 dollars per bushel)	2.29	3.00	6.50	3.27	6.14	2.99	4.43
Census Division 4 Biomass Price (2005 dollars per million Btu)	0.94	1.51	5.02	1.51	4.95	1.50	3.96
Agricultural Impacts							
Total Corn Crop (million bushels)	11,807	14,138	14,473	14,201	14,449	14,313	14,338
Corn for Ethanol (million bushels)	1,323	3,363	9,228	4,462	8,805	3,247	6,871
Percent of Corn Going to Ethanol	11	24	64	31	61	23	48
Net Corn Exports (million bushels)	1,814	2,657	-1,871	1,809	-1,544	2,747	-52
Corn Acres Harvested (million acres)	74	77	79	77	79	77	78
Corn Yield (bushels per acre)	160	183	183	183	183	183	183
Biomass Supplied (million tons)[1]	<30	41	535	48	529	126	698

[1]Biomass Supplied excludes wood and wood waste, which may be used for biomass power generation.
Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES252HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

For example, if the price of fossil fuels rose rapidly to three times the Reference Case levels, and the potential for building new U.S. nuclear capacity were significantly limited, the incremental cost of the policy through 2030, all else being equal, would be negligible, because renewable generating technologies would probably be economical without any additional incentives. On the other hand, if fossil fuel prices fell to less than $20 per barrel and wellhead natural gas prices to $2.00 per thousand cubic feet, all else being equal, the incremental cost of the policy would be considerably higher than projected in the Policy Case for this analysis.

World oil prices and U.S. natural gas prices, the rate of improvement in renewable generation and cellulosic ethanol technologies, and the availability and prices of domestic biomass and imported ethanol are key determinants of the cost of implementing the 25-percent RPS and RFS policy in this analysis. The High Price Case represents an alternative view of the future with significantly higher world oil and domestic natural gas prices. The High Technology Case represents a view that incorporates the Reference Case assumptions in all areas except renewable technology development, the availability of low-cost biomass supplies, and the rate of technological progress in developing cellulosic ethanol technology.

The other uncertainty examined for this analysis is the availability of imported ethanol at low cost. The Low-Cost Ethanol Imports Case, in addition to incorporating all the

Reference Case assumptions, assumes the availability of large quantities of ethanol imports. As expected, the impacts of the Policy on this case are dramatic: a projected 20.7 billion gallons of ethanol is imported in 2025 in the Low-Cost Ethanol Imports Policy Case, compared with 3.4 billion gallons in the Low-Cost Ethanol Imports Case, 7.7 billion gallons in the Policy Case, and 3.3 billion gallons in the Reference Case. The dramatic increase of ethanol imports in the Low-Cost Ethanol Imports Policy Case delays the need for accelerated development of domestic production facilities for corn-based and cellulosic ethanol and makes more domestic biomass available for use in electricity generation. As a result, the projected RPS and RFS credit prices are lower than those in the Policy Case, and the impacts on electricity and motor fuel prices are smaller.

High Price Policy Case

Price increases in High Price Policy Case (relative to the High Price Case) are smaller than the price increases between the Reference Case and the Policy Case, because the price of liquid petroleum products in the High Price Case is higher than those in the Reference Case and closer to the prices of the renewable fuels that replace them. As such, the shift to alternative motor transport fuels in the High Price Policy Case results in a smaller price increase relative to the High Price Case than is seen in the Policy Case relative to the Reference Case.

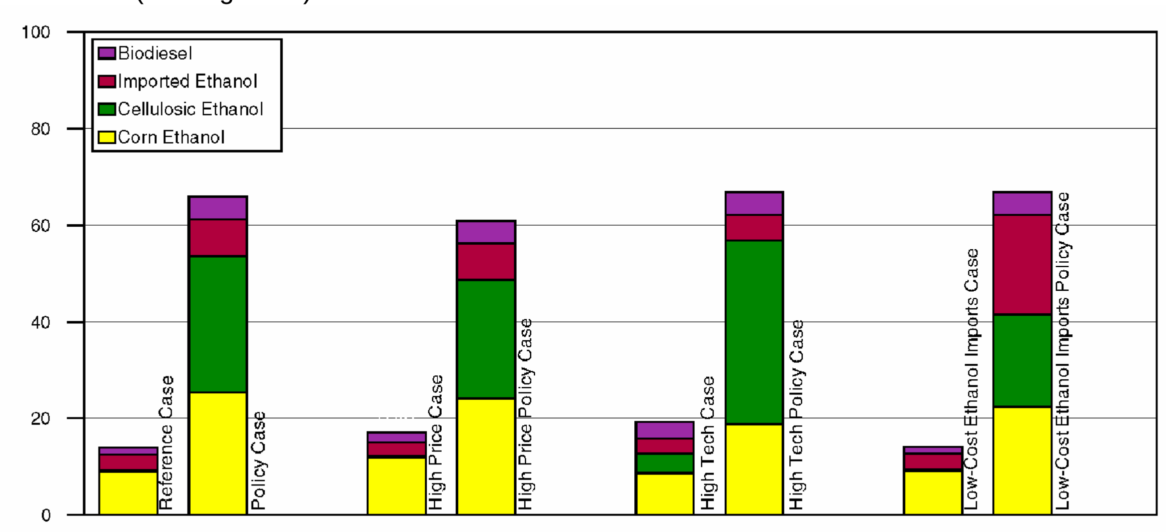
By themselves, the assumptions of the High Price Case induce an additional 2.9 billion gallons per year (32 percent) of corn ethanol production, even as the total demand for liquid fuels falls from 48.1 to 44.3 quadrillion Btu (-7.9 percent) (Figure 24). However, the product prices in the High Price Case are not high enough by themselves to induce the building of cellulosic ethanol production facilities. Consumer energy expenditures in the High Price Case are $224 billion (18 percent) above those in the Reference Case in 2025, whereas in the Policy Case consumer expenditures are only 7 percent above those in the Reference Case. In addition, the increase in consumer energy expenditures in the High Price Policy Case relative to the High Price Case in 2025, $53 billion, is 35 percent smaller than the increase in the Policy Case relative to the Reference Case (again, showing that the starting point matters).

In the High Price Policy case, renewable fuels are more competitive with petroleum fuels than projected in the Policy Case, and the RFS credit price in 2025 is 33 percent lower: $1.46 per gallon compared with $2.18 per gallon (2005 dollars). The 4-percent increase in consumer energy expenditures in 2025 in the High Price Policy Case relative to the High Price Case, to $1,513 billion, is also smaller than the 6.6-percent increase in the Policy Case relative to the Reference Case. As the price of domestically produced renewable liquids moves closer to the price of petroleum liquids, the import share of liquids declines from 60 percent in the Reference Case to 50 percent in the High Price Case and to 44 percent in the High Price Policy Case.

Because the 25-percent RFS requirement is met at a lower overall level of demand for motor fuels in the High Price Policy Case than in the Policy Case, both corn ethanol production and cellulosic ethanol production are lower, while ethanol imports are essentially the same in the two cases. Corn ethanol production increases by 16.5 billion gallons and cellulosic ethanol increases by 27.8 billion gallons in 2025 between the

Reference and Policy Case. When the Policy is applied to the High Price Case, corn ethanol production increases by 12.2 billion gallons, and cellulosic ethanol production increases by 24.4 billion gallons. Comparing the relative changes between the Policy Case and the High Price Policy Case, the reduction in corn ethanol production is much smaller than the reduction in cellulosic ethanol production due to the difference in the cost structures of corn and cellulosic ethanol plants. That is, comparing the Policy Case to the High Price Policy Case, corn ethanol production is 5.8 percent (1.4 billion gallons) lower in 2025, and cellulosic ethanol production is 12 percent (3.4 billion gallons) lower. For the new technology of cellulosic ethanol plants, cumulative learning effects lower the capital costs as more capacity is built.

Figure 24. Sources of Renewable Fuel Supply in Alternative Cases, 2025
(billion gallons)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES2525HI.D060607A, IHITECH.D060607A, IRES2525HT.D060607A, ILCBRAZIL.D060607A, and IRES2525LCB.D060607A.

Corn prices in the High Price Case, at $3.27 per bushel in 2025, are 9 percent higher than projected in the Reference Case, and 33 percent (1.1 billion bushels) more corn is used for ethanol production. In the High Price Policy Case, however, the amount of corn used for ethanol production is 4.6 percent (0.4 billion bushels) less than in the Policy Case. At the production levels projected in the analysis cases for this study, increases in the demand for corn used in ethanol production are met, for the most part, not by the planting and harvesting of more acres but by changes in net imports and consumer demand. As a result, the percentage of the total U.S. corn crop consumed for ethanol production is somewhat lower in the High Price Policy Case (61 percent) than in the Policy Case (64 percent).

The U.S. Department of Agriculture estimates that approximately 92.9 million acres of corn is planted in the United States,[34] of which 85.4 million acres is expected to be harvested,[35]

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[34]USDA/National Agricultural Statistics Survey (NASS), *Acreage, June 2007* (Washington, DC, June 29, 2007).

bringing 2007-2008 corn production to 12.8 billion bushels.[36] The 85.4 million acres harvested exceeds the level of corn acres harvested across all cases, as shown in Table 13 for 2025. The observations about the acreage planted and harvested point to the large degree of uncertainty and volatility that arise in the agricultural markets, as discussed in Chapter 2.

High Technology Policy Case

In the High Technology Case, the price of renewable liquid fuels in the transportation sector is lower than projected in the Reference Cases, because technological advances are assumed to reduce the cost of building cellulosic ethanol production facilities and the cost of the biomass supply to those facilities. The net cost of biofuel production in the High Technology Case is reduced sufficiently to make biofuels (such as cellulosic ethanol) competitive with conventional motor transport fuels without new policy mandates. As a result, cellulosic ethanol production in 2025 increases from 250 million gallons per year in the Reference Case and High Price Case to 4 billion gallons per year in the High Technology Case. In the High Technology Policy Case, however, the RFS credit price, which represents a "cross subsidy" for all qualified motor transport fuels, is still needed to achieve the Policy requirement (Table 13).

In the High Technology Policy Case, the increase in cellulosic ethanol production leads to lower corn ethanol production, lower corn prices, and lower energy expenditures by consumers for motor fuels than in the Policy Case. Cellulosic ethanol production is projected to total 38 billion gallons in 2025 in the High Technology Policy Case. As a result, corn ethanol production in 2025 is 26 percent lower in the High Technology Policy Case, at 18.9 billion gallons, than the 25.5 billion gallons projected in the Policy Case; corn prices are 32 percent lower at $4.43 per bushel (2005 dollars); and corn imports are nearly eliminated.

On the other hand, the increase in demand for biomass to be used in cellulosic ethanol plants and electric power plants in the High Technology Policy Case is substantial. From a level of less than 30 million tons supplied in 2005, the High Technology Policy Case projects total U.S. demand for biomass in 2025 at 698 million tons, or 30 percent higher than in the Policy Case. That would represent a substantial percentage of the total biomass estimated to be available for use, raising concerns about the feasibility of achieving the levels of supply that would be needed.

Total energy expenditures by consumers in the High Technology Policy Case in 2025 are projected to total $1,269 billion, 3.6 percent below the Policy Case projection and only 3 percent above the Reference Case projection. Said another way, total energy expenditures by consumers in the High Technology Policy Case in 2025 are $48 billion (3.6 percent) less than in the Policy Case and only $33 billion (2.7 percent) more than in the Reference Case.

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[35]USDA/World Agricultural Outlook Board (WAOB), *World Agricultural Supply and Demand Estimates*, WASDE-448 (Washington, D.C., July 12, 2007).
[36]*Ibid.*

Low-Cost Ethanol Imports Policy Case

In the Low-Cost Ethanol Imports Case, ethanol imports in 2025 are projected at 3.4 billion gallons—not much more than the 3.3 billion gallons projected in the Reference Case. In the Low-Cost Ethanol Imports Policy Case, however, imports of ethanol from Brazil total 20.7 billion gallons in 2025, an increase of 170 percent from the 7.7 billion gallons projected in the Policy Case.

Like the High Price Policy Case, the Low-Cost Ethanol Imports Policy Case predominantly affects demand for cellulosic ethanol in comparison with the Policy Case. Cellulosic ethanol production in 2025 falls from 28 billion gallons in the Policy Case to 19.2 billion gallons in the Low-Cost Ethanol Imports Policy Case (a 32-percent decrease), whereas corn ethanol production falls from 25.5 billion gallons to 22.4 billion gallons (12 percent), because lower demand for corn reduces corn prices, making corn-based ethanol more competitive with cellulosic ethanol.

Given the level of corn ethanol displaced, the Low-Cost Ethanol Imports Policy Case results in a smaller reduction in corn prices and a smaller reduction in RFS credit prices relative to the Policy Case than are projected in the other alternative policy cases examined. For example, the 2025 price of corn in the Low-Cost Ethanol Imports Policy Case, at $5.57 per bushel in 2005 dollars, is 9 percent lower than projected in the High Price Policy Case and 26 percent higher than projected in the High Technology Policy Case. The RFS credit price of $1.83 per gallon in 2005 dollars in 2025 in the Low-Cost Ethanol Imports Policy Case is 25 percent above the RFS credit price in the High Price Policy Case and 37 percent above that in the High Technology Policy Case.

In summary, although the Low-Cost Ethanol Imports Policy Case reduces RFS credit prices by 16 percent and corn prices by 14 percent relative to the Policy Case projections, the savings achieved are not as great as those in the other alternative policy cases examined in this study.

Economic Impacts

Key economic results illustrating the projected effects of implementing the Policy in the Reference Case and in the High Price and High Technology alternative reference cases are summarized in Table 14. As noted in Chapter 3, implementation of the proposed Policy in the electricity generation and transportation markets would lead to higher energy prices as consumers substitute more expensive renewable fuels for less expensive fossil fuels; and the higher energy prices would lead to a decline in economic activity.

Table 14. Summary of Economic Impacts of Alternative Policy Cases in 2025

	Reference	Policy	High Tech	High Tech Policy	High Price	High Price Policy
Components of GDP (billion 2000 dollars)						
GDP	19,670	19,595	19,676	19,645	19,673	19,628
Consumption	13,732	13,693	13,736	13,724	13,605	13,591
Investment	3,772	3,762	3,773	3,755	3,762	3,761
Government	2,542	2,549	2,542	2,545	2,549	2,555
Exports	4,902	4,836	4,903	4,864	4,846	4,795
Imports	4,966	4,960	4,966	4,943	4,691	4,695
Aggregate Prices in the Economy						
WPI: Fuel and Power (1982 = 1.0)	2.12	2.25	2.11	2.16	2.59	2.66
CPI: Energy (1982/84 = 1.0)	2.51	2.79	2.49	2.63	3.05	3.22
CPI: All Urban (1982/84 = 1.0)	2.90	2.98	2.90	2.94	2.90	2.96
WPI: All commodities (1982 = 1.0)	1.94	2.06	1.94	1.99	2.03	2.11
Inflation Rate, Unemployment Rate, and Federal Funds Rate						
Inflation	2.26	3.02	2.24	2.87	2.11	2.67
Unemployment Rate	4.54	4.70	4.53	4.53	4.54	4.64
Federal Fund Rate	5.10	5.52	5.10	5.50	4.75	5.05
Industrial Sector (billion 2000 dollars)						
Total Industrial	8,590	8,344	8,595	8,436	8,556	8,385
Nonmanufacturing	1,937	1,859	1,937	1,891	1,971	1,910
Manufacturing	6,654	6,485	6,658	6,545	6,585	6,475
Energy-Intensive	4,528	1,470	1,529	1,487	1,494	1,451
Non-Energy-Intensive	5,126	5,015	5,129	5,058	5,091	5,024
Disposable Income	15,171	15,137	15,176	15,181	14,867	14,856

Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHITECH.D060607A, IRES2525HT.D060607A, IHIPRICE.D060607A, and IRES252HP.D060607A.

In the High Technology Policy Case, accelerated progress in the development and improvement of renewable generation and cellulosic ethanol technologies and greater availability of relatively low-cost domestic biomass supplies make the policy easier to achieve than in the Policy Case. Similarly, in the Low-Cost Ethanol Imports Policy Case, the policy is easier to achieve because large volumes of ethanol imports are available at relatively low cost. In both cases, RPS and RFS credit prices are lower than projected in the Policy Case, ultimately mitigating the cost of the Policy to consumers and its impacts on the U.S. economy. The cost of the Policy is lower in the alternative policy cases, because renewable fuels are already more competitive with traditional fossil fuels in the corresponding alternative reference cases, according to the scenario definitions.

In the High Price Policy Case, the economic impacts of imposing the Policy on the High Price Case, which assumes higher fossil fuel energy prices than in the Reference Case, are smaller than the impacts in the High Technology Policy Case and Low-Cost Ethanol Imports Policy Case, which are based on alternative reference cases with lower energy prices. With higher prices for liquid fuels and natural gas: (a) the aggregate price of energy is higher; (b) GDP and consumption are lower; (c) the demand for energy, specifically for electricity and liquids, is lower; and (d) the proportion of renewable fuels used is higher in both the electric power and motor transportation sectors.

When fossil fuel prices are higher, renewable generation and biofuels are more competitive in a greater number of situations, and so a relatively smaller economic incentive is needed to achieve the necessary market penetration. Consequently, when the RPS and RFS policy requirements are added to the High Price Case, the negative impacts on key energy and economic indicators in the High Price Policy Case are smaller than those in the Policy Case relative to the Reference Case. The result is a pattern of lower RPS and RFS credit prices, smaller increases in electricity prices, and smaller increases in motor transportation fuel prices. Therefore, the projected losses in real GDP, consumption, and industrial output are smaller.

Key energy sector results illustrating the projected effects of implementing the Policy in the Reference Case and in the High Price and High Technology alternative reference cases are summarized in Table 15. In the High Price Policy Case, consumer energy prices rise steadily through 2025, to almost 6 percent above prices in the High Price Case—roughly one-half of the percentage increase projected in the Policy Case relative to the Reference Case (Figures 25 and 26). Overall, the CPI for All Urban consumer prices is as much as 2.5 percent higher in the High Price Policy Case than in the High Price Case (Table 14). The percentage increases in energy prices projected in the High Technology Policy Case relative to those in the High Technology Case are even smaller, averaging only 2 percent in 2025. Smaller price changes mean smaller impacts on real GDP, consumption, and industrial production as compared with the impacts in the High Price Policy Case relative to the High Price Case.

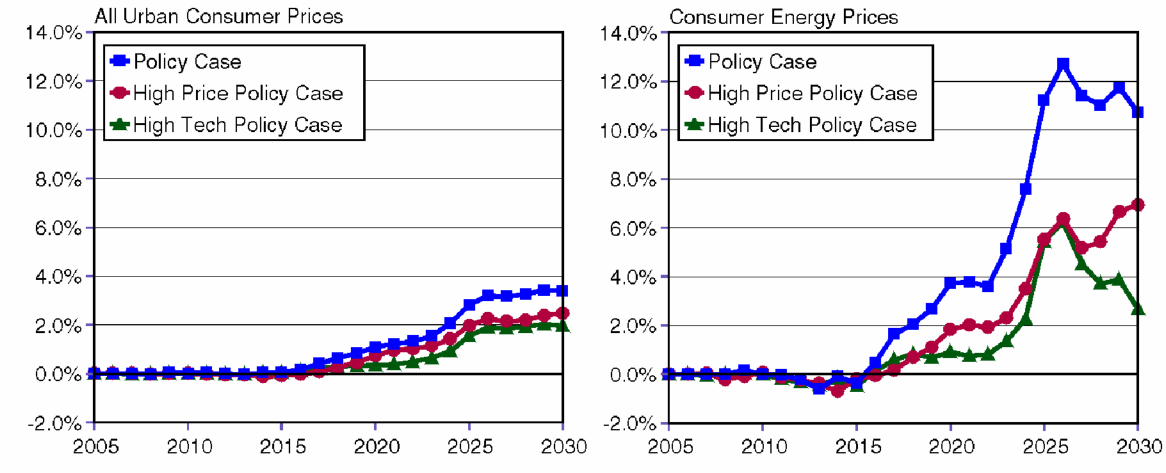
Relative to the High Price Case, discounted GDP losses in the High Price Policy Case total $165 billion (less than 0.1 percent)—equal to slightly more than one-half the impact on GDP in the Policy Case relative to the Reference Case (Figure 27). In other words, because price changes from the High Price Case to the High Price Policy Case are smaller than those from the Reference Case to the Policy Case, the impacts on national consumption and GDP are smaller. After 2025, when energy prices peak, both real GDP and consumption begin to return to baseline levels. In the High Technology Policy Case, GDP losses in 2025 relative to projected GDP in the High Technology Case are comparable to, but smaller than, those in the High Price Policy Case (relative to the High Price Case), illustrating the beneficial effect of faster-than-expected technological progress.

Table 15. Summary of Energy Impacts of Alternative Policy Cases in 2025

	Reference	Policy	High Price	High Price Policy	High Tech	High Tech Policy
RPS Credit Price (2005 cents per kilowatthour)	NA	4.8	NA	4.6	NA	3.4
RFS Credit Price (2005 dollars per gallon of biofuel)	NA	2.18	NA	1.46	NA	1.34
Consumption (quadrillion Btu)						
Liquids	49.1	48.3	45.2	45.1	49.1	48.8
Natural Gas	26.8	25.6	24.7	24.4	26.6	25.4
Coal	30.3	24.1	32.7	26.0	29.6	24.5
Nuclear	9.2	8.5	10.1	8.5	9.2	8.5
Hydropower	3.1	3.3	3.1	3.2	3.1	3.2
Biomass	3.9	11.4	4.3	11.3	5.3	13.0
Other Renewables	1.4	7.0	1.5	6.5	1.5	5.6
Total	**123.8**	**128.3**	**121.5**	**125.2**	**124.4**	**128.9**
Average Prices: Selected Fuels						
Transportation Fuels						
Motor Gasoline (2005 dollars per gallon)[1]	2.16	2.44	3.06	3.20	2.12	2.26
Diesel (2005 dollars per gallon)[2]	2.21	2.70	2.96	3.27	2.22	2.49
E85 (2005 dollars per gallon)	2.22	1.89	2.51	2.49	2.15	1.74
Biomass (2005 dollars per million Btu)[3]	1.51	5.02	1.51	4.95	1.50	3.13
Electricity Fuel Input Prices (2005 dollars per million Btu)						
Steam Coal	1.62	1.59	1.76	1.69	1.61	1.56
Distillate	10.29	10.19	15.50	15.60	10.23	10.19
Residual Fuel Oil	6.59	6.57	11.92	11.79	6.58	6.61
Natural Gas	5.96	5.72	6.98	6.78	5.98	5.62
Average Retail Electricity Prices (2005 cents per kilowatthour)	**8.0**	**8.3**	**8.2**	**8.5**	**8.0**	**8.1**
Undiscounted Cumulative Expenditures, 2009-2025 (billion 2005 dollars)[4]						
Electricity Revenues from Retail Sales	5,838	5,833	6,015	6,019	5,828	5,798
Motor Transport Expenditures	8,493	8,759	10,773	10,924	8,482	8,616
Subtotal	14,331	14,592	16,788	16,924	14,260	14,414
Total U.S. Energy Expenditures	**18,643**	**18,879**	**21,748**	**21,873**	**18,616**	**18,675**
Discounted Cumulative Expenditures, 2009-2025 (billion 2005 dollars)[5]						
Electricity Revenues from Retail Sales	3,511	3,507	3,619	3,616	3,506	3,491
Motor Transport Expenditures	5,121	5,232	6.396	6,462	5,117	5,175
Subtotal Expenditures	8,632	8,739	10,015	10,098	8,623	8,666
Total U.S. Energy Expenditures	**11,271**	**11,361**	**13,017**	**13,063**	**11,257**	**11,277**

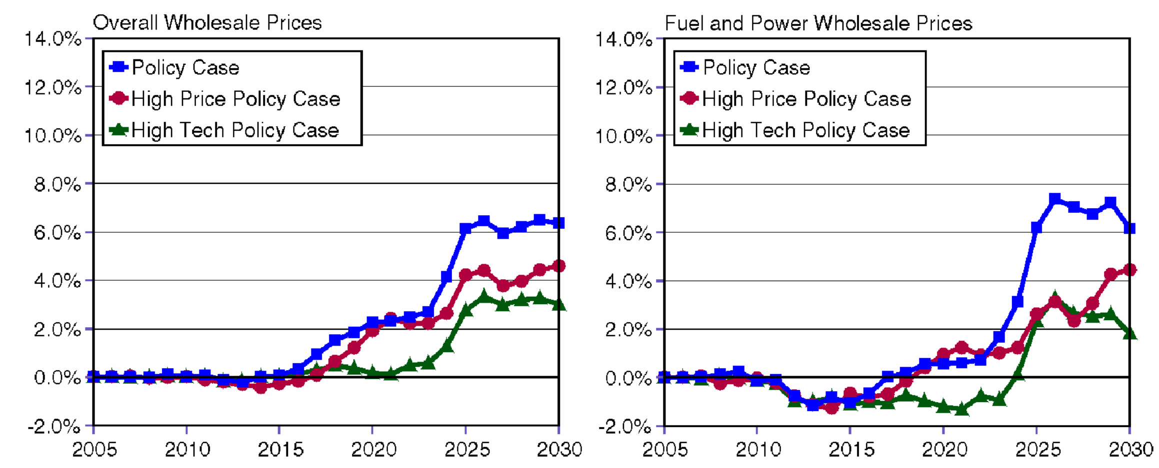
[1]Motor gasoline contains up to 10 percent ethanol.
[2]Diesel fuel may contain up to 20 percent biodiesel from renewable sources.
[3]Census Division 4 price.
[4]Simple undiscounted sum (2005 dollars).
[5]Discounted at 7 percent per year back to 2009.
Source: EIA Office of Integrated Analysis and Forecasting. National Energy Modeling System runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES252HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Figure 25. Consumer Price Impacts in the Policy Cases
(percent change from corresponding reference cases)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES2525HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Figure 26. Wholesale Price Impacts in the Policy Cases
(percent change from corresponding reference cases)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES2525HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Cumulative discounted consumer expenditures from 2005 to 2025 in the High Price Policy Case are only $35 billion (0.02 percent) lower than projected in the High Price Case (Figure 28). As is typically the case for GDP, consumption declines generally grow over time as energy prices continue to rise in the High Price Policy Case relative to the High Price Case; however, as the increase in energy prices subsides, the consumption declines also slow, and eventually they are reversed. On an *undiscounted* basis, the declines in GDP and consumption from the High Price Case to the High Price Policy Case are much larger.[37]

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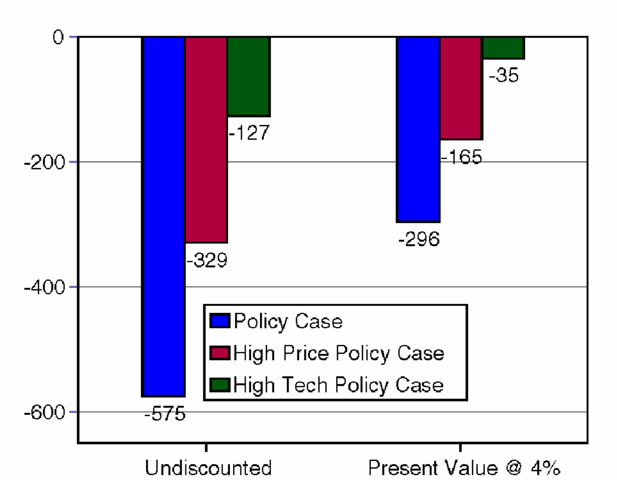
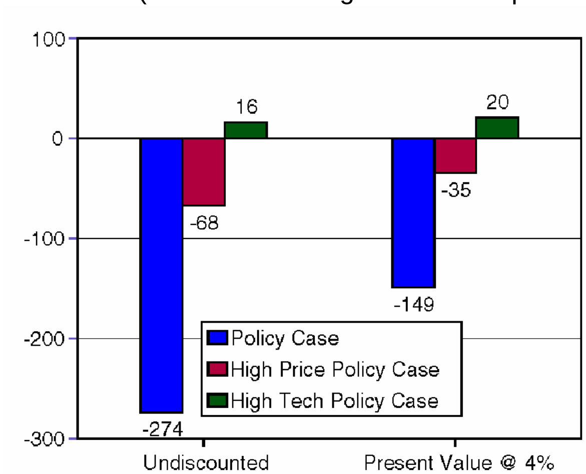
[37]Using the economic principle of discounting and the time value of money tends to weigh losses at the beginning of a period more than equal losses at the end of a period. For example, a dollar loss in 2030 is valued at about $0.45 in 2010 when discounted at 4 percent.

Figure 27. GDP Impacts in the Policy Cases
(cumulative change from corresponding reference cases, billion 2000 dollars)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES2525HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Figure 28. Consumption Impacts in the Policy Cases
(cumulative change from corresponding reference cases, billion 2000 dollars)



Source: National Energy Modeling System, runs IBASE.D060607A, IRES2525.D060607A, IHIPRICE.D060607A, IRES2525HP.D060607A, IHITECH.D060607A, and IRES2525HT.D060607A.

Appendix A. Request Letters

United States Senate

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

WASHINGTON, DC 20510–6175

January 8, 2007

Mr. Guy F. Caruso
Administrator
Energy Information Administration
U.S. Department of Energy
El-1, Forrestal Building
1000 Independence Ave. SW
Washington, DC 20585

Dear Mr. Caruso:

Increased prices of motor fuels in recent years have promoted interest in developing less expensive and domestic fuel alternatives to power vehicle fleets. For various reasons, ethanol has become the most popular of these alternatives. While Chairman of the Senate Committee on Environment and Public Works, I successfully moved legislation that became the historic renewable fuels title to last year's comprehensive energy bill (Public Law No: 109-58, August 8, 2005). Since that time, I chaired three oversight hearings concerning that title and future transportation fuels, and a legislative hearing on a bill to improve the permitting process for critical domestic fuels infrastructure.

Ensuring inexpensive, reliable, and practical sources of fuel for all Americans is a national priority. Therefore, I have been reviewing the various proposals with great interest both as ranking member of the committee of jurisdiction as well as a Senator from Oklahoma, one of the foremost energy states in the country.

To that end, I would appreciate your analysis of an assumed new federal mandate beginning in 2007 that requires 25% of the total energy used in the electric power and motor transportation fuels sectors come from renewable sources by 2025 (the "25 x '25 Policy Scenario"). You should use the relevant AEO 2007 forecast cases.

In particular, please apply the 25 x 25 Policy Scenario for each of the following AEO 2007 oil price/economic growth cases:

- Reference case (Mid-range economic growth with mid-range oil price)
- Reference case with low economic growth;
- Reference case with high economic growth;
- Low oil price case;
- High oil price case.

For each 25 x 25 Policy Scenario, please detail the difference in total U.S. energy expenditures (constant $) compared to the above-stated cases for the forecast period from 2007-2025. Please also provide the energy prices under each 25 x 25 Policy Scenario for the major fuels used in the

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electric power and motor transportation fuels sectors, including gasoline and retail electricity, shown separately for fossil-based and renewables-based fuel. Assume that federal subsidies for the various energy forms are not extended beyond their current statutory expiration dates. Also, please provide the estimated energy expenditures for 25 by 25 in total and also a subtotal for the electricity sector and a subtotal for the transportation sector.

If there would likely be any significant regional differences, please identify and estimate in terms of energy prices, expenditures, and economic impacts.

Finally, please describe the cellulosic technologies that are likely to be employed in meeting the 25 by 25 goal, and provide a forecast of the costs of renewable fuels feedstock.

Please provide me with your report no later than February 15, 2007.

Sincerely,

James M. Inhofe

United States Senate
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
WASHINGTON, DC 20510-6175

January 30, 2007

Dr. Howard Gruenspecht
Deputy Administrator
Energy Information Administration
1000 Independence Ave. SW
Washington, D. C. 20585

Dear Dr. Gruenspecht:

This letter follows up on Senator Inhofe's letter of January 8, 2007, which requested that EIA provide an analysis of a proposed Federal mandate for renewable energy. It reflects a conversation I had with your staff on January 19 and provides further clarification of the request. The key features of the renewable energy mandate discussed included:

- The policy instrument to be used,
- How the sectors are covered (jointly or separately),
- What fuels are considered qualifying renewables,
- How the renewable shares are defined,
- Who is covered,
- What happens after 2025,
- Should any specific ethanol-related policies be assumed that facilitate the renewable fuels target, and
- Which scenarios should be evaluated.

Based on my discussions with your staff, I understand that EIA plans to use the following analysis approach:

- Each sector (electricity sales and gasoline plus diesel transport fuels) would meet its own renewable targets, that is:
    - 25 percent of electricity sales would be from renewable generators
    - 25 percent of gasoline plus diesel sales would be from either ethanol or biodiesel on a volumetric basis.
- Four cases will be prepared based on the reference and high oil price cases from the *Annual Energy Outlook 2007,* with and without the renewable standards.
- Existing renewable credit programs and ethanol import tariffs are assumed to sunset at their legislatively mandated dates in all cases.

<u>The key assumptions to be used in the Electricity Sector include:</u>

- Policy Instrument: Renewable Portfolio Standard (RPS) with tradable credits
- RPS characteristics:

- Qualifying renewables include:
    - Biomass (used in dedicated plants or co-firing with other fuels)
    - Geothermal
    - Municipal solid waste (including landfill gas)
    - Solar thermal
    - Photovoltaic
    - Wind
    - Incremental Hydroelectricity above that existing in 2006.
- Existing qualifying generators (except for hydroelectricity) do receive credits.
- The required share is expressed as a percentage of electricity sales in kilowatthours.
- The required share starts at the share of qualifying renewable generation in 2006, increases to 25 percent in 2025, and is held at 25 percent for subsequent years (i.e. no provision sunsets).
- All retail electricity sellers are included.
- RPS (electricity) credit trading is only allowed within the electricity sector.
- There is no credit price cap.

<u>The key assumptions to be used in the Motor Transportation Sector include:</u>

- Policy Instrument: Renewable Fuels Standard (RFS) with tradable credits.
- RFS characteristics:
    - Qualifying renewables include:
        - Corn-based ethanol
        - Cellulosic-based ethanol
        - Biodiesel production from all sources including oil-based beans/seeds.
    - Existing qualifying sources do receive credits.
    - The required share is expressed as a percentage based on current *AEO2007* reference case projections for overall gasoline and diesel consumption, rising to 25 percent of gasoline plus diesel motor fuel consumption.
    - The required renewable share starts at the share of qualifying biofuels sold in 2006, increases gradually to 25 percent in 2025, and is held at 25 percent for subsequent years (i.e. no provision sunsets).
    - RFS credit trading may only occur within the transportation sector.
    - There is no credit price cap.

- Measures to facilitate compliance (e.g., mandates to produce cars, E-85 pumps at stations, etc.) will take the form of provisions in S.23, the Biofuels Security Act of 2007.

Ideally, we would like to have the report in March 2007. However, given the above analytical structure and agency workload, I understand that such a date may not be feasible and ask that the analysis be completed as soon as time and resources permit.

If you have any questions regarding this clarification of the request, please don't hesitate to contact me at (202) 224-0516.

Sincerely,

Frank Fannon

Appendix B. Key Updates and Changes to the *AEO2007* Reference Case Assumptions

The following list identifies the changes that were made to the *AEO2007* version of the NEMS models, input assumptions, and policy assumptions to allow analysis of the proposed Policy.

Macroeconomic Changes from *AEO2007* Reference Case

- The 51-cent-per-gallon subsidy on ethanol was allowed to expire as stated in current U.S. law.

- Ethanol was included in the transportation fuels as input to the Global Insight macroeconomic model because of its magnitude.

- For the Policy cases, the producer price index for farm products was increased by 50 percent of the corn price increase derived from the renewables module. Grains, livestock, poultry, eggs, and dairy constitute 90 percent of the producer price index for farm products. On a wholesale level, this assumes that 60 percent of the corn price increase was passed on for the above mentioned categories.

- Ethanol imports were included in non-petroleum industrial supplies and materials imports in the Global Insight macroeconomic model.

Petroleum Market Module Changes from *AEO2007* Reference Case

- The 51-cent-per-gallon blenders' subsidy on ethanol and the 54-cent import tariff were allowed to expire simultaneously in 2010, approximating current U.S. law.

- While the blenders' tax credit is set to expire 1 year after the ethanol import tariff, both laws were assumed to expire in the same year to preserve the intent of the requested analysis.

- Added an improved representation of international ethanol import supply as a function of price.

- Updated the cellulose ethanol representation from a simple input supply curve to a merchant plant representation that incorporates capital investment and production decision making as well as technology learning.

- Updated the biodiesel representation to a merchant plant representation and added the ability to process animal fats.

- Added totally new logic to represent the demand for E85 as function of price and a number of other key consumer preferences within the Petroleum Market Module to represent producer and consumer behavior in an RFS policy. The new formulation was necessary to ensure and accelerate convergence of demand and prices in the RFS case.

- Incorporated the flexibility to choose between imports of petroleum gasoline and gasoline blending components.

- Increased the ethanol blending percentage in non-California reformulated and oxygenated gasoline to 10 percent. The change represents a recent EIA reassessment of the market. The change, while critical in the Policy cases, has little influence on the reference or high price cases of *AEO2007*.

- Added logic to implement EPACT2005 Provision 942 (Cellulosic Biofuel Production Incentives) in the Policy cases. The extension allows for further support for cellulosic ethanol if prices are expected to be economic sooner in the time horizon through an RFS.

- Lowered the DDGS netback price for ethanol production whenever corn-ethanol production exceeds 18 billion gallons.

- Adjusted maximum build rates for ethanol plants consistent with current market investment trends.

The *AEO2007* analysis assumed that the maximum ethanol import quantity that would be available at any price through the entire projection horizon would be about 900 million gallons per year. A review of a recent study for potential Brazilian ethanol production and exports to the United States through 2012 provided new data points through which simple exponential supply curves were estimated by year.[38] Whether the levels of ethanol supply from Brazil to the United States will increase as assumed by these curves will depend critically on the level of investments made in Brazil to expand sugar cane crop production and ethanol conversion facilities and the competition for the ethanol from the rest of the world. The removal of the import tariff combined with the new ethanol import supply curves results in ethanol imports that are three times larger than in the *AEO2007* reference case.

The study cited above claims that there are over 90 million hectares (over 200 million acres) of cleared but idle, non-environmentally sensitive, land available for development of ethanol production. If the land were aggressively developed for sugar cane production, Brazilian ethanol production could grow to over 50 billion gallons per year. Large-scale investments for plant and infrastructure, estimated to be between $150 billion to $250 billion dollars, would be required to build roads, purchase farming equipment, expand the ethanol transportation infrastructure, build new conversion plant facilities, and provide for port and ship expansions. One of the scenarios addressed in this analysis, the Low-Cost Ethanol Imports Case assumes that such investments are made for Brazilian ethanol development.

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[38]University of Campinas, Sao Paulo, Brazil, *Study of the Possibilities and Impacts of the Production of Large Quantities of Ethanol with the Aim to Partially Replace Gasoline in the World.*

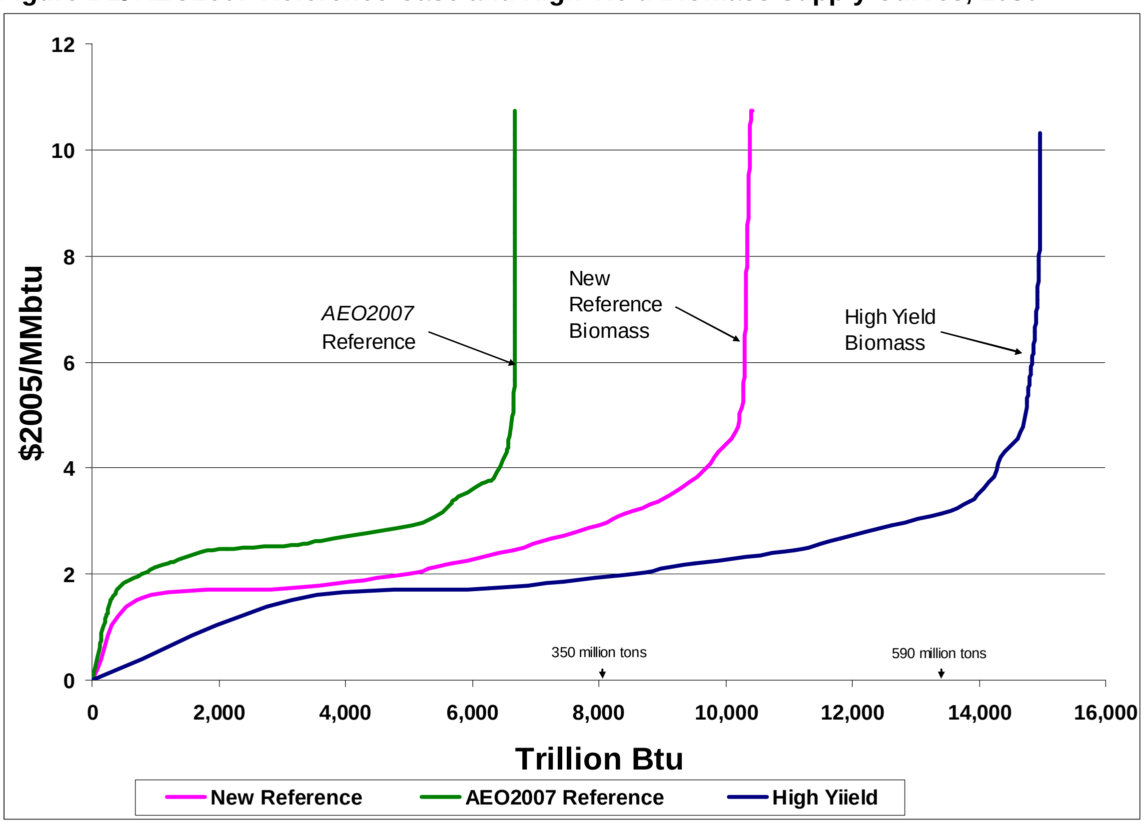
Renewable Market Module Changes from *AEO2007* Reference Case

- Added offshore wind technology as a capacity expansion option in selected coastal regions, with revised cost and performance estimates.

- Updated corn and biomass feedstock costs consistent with University of Tennessee POLYSYS study.

EIA's estimates of biomass supply curves were taken from the U.S. Department of Agriculture's latest estimates through 2015, which were developed under contract with Dr. Ugarte at the University of Tennessee using an integrated land and crop competition model. EIA contracted with Dr. Ugarte to extend these curves through 2030. The corn supply curves also were developed using POLYSYS and were generally higher-priced than those in *AEO2007* for the same level of demand; however, the maximum availability of corn supply in the new estimate is much larger than the *AEO2007* reference case and allows for corn imports when corn prices and demand are sufficiently high. In addition to the reference case, a high yield case was constructed to evaluate the impact of potentially higher biomass crop yields. Similar to the reference case, the biomass supply curves through 2015 were obtained from the USDA and extended through 2030 by Dr. Ugarte under contract to the EIA (Figure B1).

Figure B1. *AEO2007* Reference Case and High Yield Biomass Supply Curves, 2030



Source: Dr. Daniel de la Torre Ugarte, University of Tennessee. Using the agricultural model POLYSIS.

Transportation Module Changes from *AEO2007* Reference Case

- The Policy cases incorporated two key provisions of S.23—the manufacture of dual-fueled vehicles and the expanded infrastructure for distribution of fuels like E85—as stated by study request letter.

S.23 requires that all new light-duty vehicle (LDV) sales be dual-fuel capable (high percentage blends of ethanol and gasoline and biodiesel and diesel) by 2017. Such provisions will probably be vigorously debated and opposed by LDV manufacturers and owners of affected fuel dispensing stations. Since the potential to produce domestic biodiesel supply is expected to be much smaller than the potential to produce domestic ethanol supply, all new LDV sales were assumed to be E85 capable by 2017. The second provision requires that at least 25 percent of all gasoline distribution stations provide E85 refueling. The costs of developing such an infrastructure will be significant, but S.23 does not specify who will bear the costs. It is likely that such costs will be borne at least in part by consumers and possibly by the firms required to provide the dispensing stations. Such costs, which were not available and were not estimated for this analysis, could significantly increase the economic impacts on the U.S. economy.

Electricity Market Module Changes from *AEO2007* Reference Case

- Modified the interregional transmission cost structure to allow renewable capacity additions from one region to serve adjacent regions, with higher associated transmission costs, which is especially important in an RPS scenario.

- Improved the representation of competition for biomass for electricity generation and cellulosic ethanol production.

- Added offshore wind technology as a capacity expansion option in selected coastal regions, with revised cost and performance estimates.

Because a combined RPS and RFS had never been previously analyzed, the logic for equilibration of biomass supply and demand between the electric power sector and the motor transportation sector needed to be created. The newly constructed algorithm equates the biomass supply price between both sectors.