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TECHNICAL
REPORT

Impacts on U.S. Energy Expenditures and Greenhouse-Gas Emissions of Increasing Renewable-Energy Use

Appendix A

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Prepared for the Energy Future Coalition

RAND

Environment, Energy, and Economic Development

A RAND INFRASTRUCTURE, SAFETY, AND ENVIRONMENT PROGRAM

The research in this report was conducted at the request of the Energy Future Coalition under the auspices of the Environment, Energy, and Economic Development Program (EEED) within RAND Infrastructure, Safety, and Environment (ISE).

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APPENDIX A

Baseline Data and Numerical-Parameter Assumptions

In this appendix, we detail the numerical assumptions and baseline figures going into our models. We first summarize the baseline information from the 2006 AEO. We then discuss the assumptions used for the electricity and motor-fuel markets. Each of these sections contains a description of the renewable-energy technologies and assumptions used in modeling the primary fossil-fuel energy markets (oil, coal, and natural gas). The last two sections show the methods and data used to calculate changes in CO_2 emissions and the ranges of key parameters used in our uncertainty analysis.

Baseline Figures for Use in Model Benchmarking

As noted, we use the 2006 AEO reference-case scenario for 2025 to benchmark the calculations. Table A.1 summarizes some key, basic features of this scenario relative to actual figures for 2004, while Figure A.1 shows the assumed price path for crude oil in this EIA scenario. For completeness, we also show comparable information from the EIA high–oil-price scenario.

Figure A.1 shows that, in EIA's reference case, crude-oil prices decline to about $45 per barrel followed by an increase in the latter part of the projection period. Crude-oil prices steadily increase in the high–oil-price case and exceed $80 per barrel in 2025. EIA has revised these projections upward in the 2007 and 2008 AEOs. However, crude-oil prices in the reference-case projections follow the same general trend: Prices decline from current levels in the initial period, followed by a steady increase in the latter portion of the projection period.

One other important piece of baseline information for the analysis is the expected amount of new capacity that will be built between 2010 and 2025 and for which planning has not started.

As shown in Table A.2, for the reference case of its 2006 AEO, EIA projected 148.9 GW of new fossil-fuel and nuclear-power capacity to be built between 2010 and 2025. This includes capacity built to replace current capacity likely to be retired during this period, as well as capacity built to meet increasing demand for power. We use 2010 capacity plus any currently planned capacity as the baseline for assessing how a 25x'25 policy could cause future capacity substitution. We assume that this baseline of built and planned capacity in 2010 is unlikely to be affected by a 25x'25 policy requirement. Renewable electricity could substitute for new capacity scheduled to come online after 2010 if that prospective policy requirement were imposed soon.

Table A.1
EIA 2006 *Annual Energy Outlook* Projections and 2004 Observed Data

Projection	2004	AEO Scenario for 2025	
		Reference Case	High Oil Price
GDP (billions of 2000 chain-weighted dollars)[a]	10,756	20,123	20,100
Electricity production (billions of kWh)	3,612	4,945	4,944
Coal	1,916	2,728	3,084
Natural gas	486	775	411
Nuclear	789	871	871
Hydroelectricity	265	299	299
Other renewable	54	187	201
Average household price for electricity (2004 cents/kWh)	8.9	8.4	8.6
Motor-fuel use			
Gasoline and diesel (millions of barrels per day of oil equivalent)	11.07	15.23	13.84
Unconventional	0.00	0.58	1.00
Average wholesale price of motor fuels (2004 $/gallon)	1.22	1.53	2.41

SOURCE: EIA (2006b).

[a] *Chain weighted* refers to a method of calculating GDP that has updating of weights used in the summation over time (Jones, 2002).

Figure A.1
EIA AEO 2006 Crude-Oil Price Projections

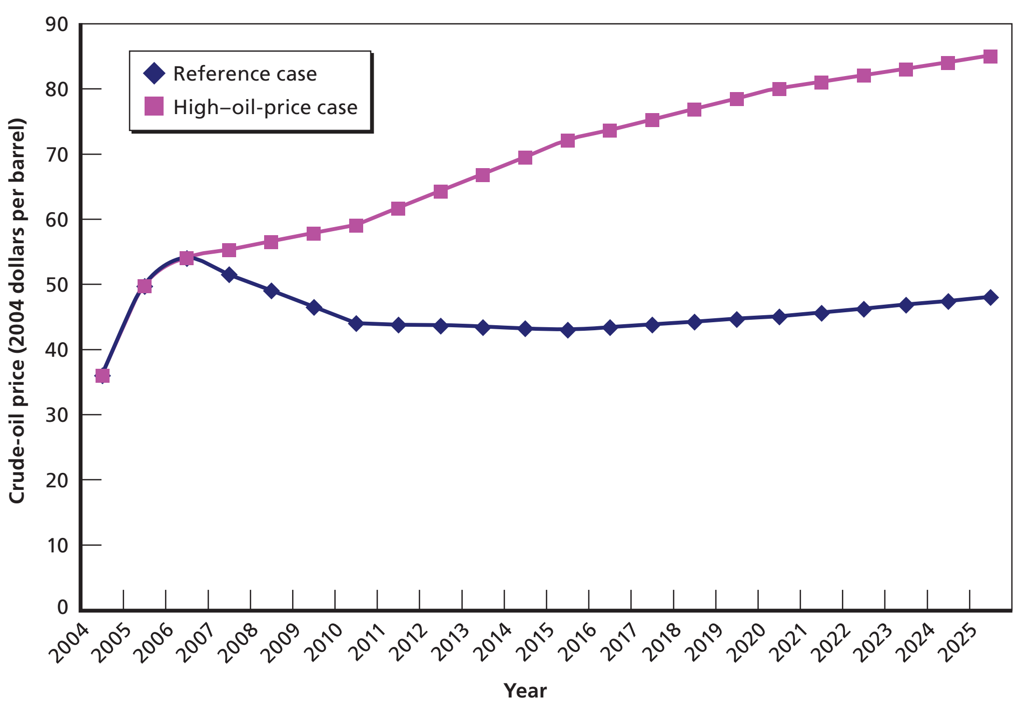

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Table A.2
2006 AEO Projections for New Electricity Capacity Added from 2010 to 2025

Type	Coal	Natural Gas Combined Cycle	Combustion Turbine	Nuclear	Wind	Biomass	Other Renewable
Amount (GW)	74.4	41.9	26.6	6.0	3.53	1.45	4.14

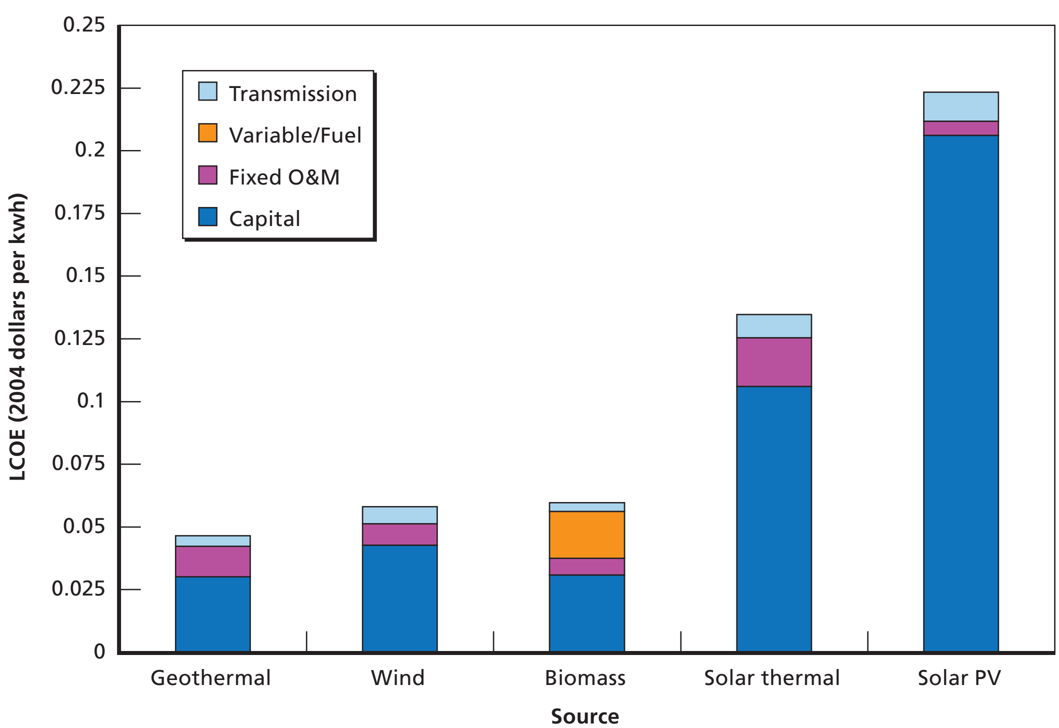
SOURCE: EIA (2006b, Tables A.9 and A.16).

Assumptions About Renewable-Electricity Costs

In evaluating the options for substituting successive amounts of renewable for nonrenewable capacity in 2025, we rely initially on EIA estimates for the LCOE (see Figure A.2). These costs are the average costs associated with the various technology alternatives at the level of power generation specified for each in the 2006 AEO reference case.

We use 2020 costs as opposed to 2025 because most power plants will need to be already constructed or under construction by this point to meet the 2025 target. EIA's cost projections actually have minimal cost change between 2020 and 2025 for geothermal, wind, and biomass. They do show some progress for solar-thermal and -PV costs.

Figure A.2
AEO 2006 Renewable-Electricity Cost Projections for 2020



SOURCES: EIA (2006a, 2006b) reference-case cost assumptions; Beamon (2007a).
NOTE: O&M = operation and maintenance.
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EIA's estimates of renewable-technology costs give us a point of departure, or a benchmark, for developing alternative supply curves for the technologies. EIA uses expert judgment in assessing future technology costs. But it is widely recognized that there are uncertainties about these future costs. Renewable-technology performance and competitiveness may progress significantly or more slowly. To take into account this uncertainty, we allow each technology's benchmark levelized cost to vary within a range, as discussed in the presentation that follows of our uncertainty analysis.

The marginal costs of most renewable technologies can be expected to increase as generating capacity expands, because renewable energy is a site-specific resource and costs rise as higher-quality sites are developed, leaving lower-quality sites for the next increments of capacity. We address this in our construction of marginal costs by treating the benchmark figures discussed earlier as the marginal cost of the first increment of added supply (i.e., the vertical intercept of the marginal-cost curve). How rapidly costs will rise from this level will depend on several uncertain factors, among them the potential for unit cost savings as output expands due to economies of scale and learning by doing. We describe next how we have accounted for these various factors in developing cost curves for each renewable technology.

Wind

Potential wind-farm sites vary in several factors that affect their development costs, such as average wind speeds and distance from transmission lines. EIA uses a coarse, aggregate set of cost-escalation factors to reflect how development costs increase at lower-quality sites. The escalation factors classify potential regions into several cost levels, account for differences in wind quality, distance from transmission lines, and site-development costs. Their capacity data are based on geographic information system (GIS) analysis of average wind speeds throughout the United States and applying filters to exclude areas that are too far from existing transmission lines, too mountainous to develop a site, and lands on which wind-power development is an incompatible land use, such as military bases and national parks (EIA, 2006a). Table A.3 shows this information: escalation factor at different steps in the cost curve and the corresponding LCOE based on EIA's baseline cost.

We use capacity and cost assumptions from both EIA and Resources for the Future (RFF). EIA applies a set of cost multipliers to account for higher development costs of remote sites, poorer wind quality, costs of upgrading transmission lines, and increasing costs for

Table A.3
Wind Supply Curve Data

Cost Escalation (%)	LCOE (2004 dollars per megawatt-hour [MWh])	Capacity (GW)	Potential Generation (GW-hours [GWh])
0	58.2	27.7	91,237
20	69.8	40.5	133,397
50	87.2	80.6	265,477
100	116.3	87.7	288,863
200	174.5	2,223.2	7,322,687

SOURCES: Petersik (1999), Paul and Burtraw (2002).

competition over land. These multipliers increase wind costs by 20 percent, 50 percent, 100 percent, and 200 percent over the initial baseline cost. The capacity estimates were developed for EIA and are used in the NEMS model; they are also used in RFF's Haiku model (Petersik, 1999; Paul and Burtraw, 2002). Table A.3 shows an enormous amount of potential wind capacity, but more than 90 percent is from lower-quality sites in the highest cost category. We use an average capacity factor[1] of 0.38 from the AEO 2006 to estimate the potential generation in each category.

For reference, the AEO 2006 projection for electricity consumption from electric utilities in 2025 is 4.9 million GWh (see Table A.1), and wind generation in the reference case is 63,000 GWh (slightly more than 1 percent of the total). Total potential generation in the first four cost levels is slightly more than 15 percent of total electricity demand. Therefore, significant expansion of wind power would require developing the lowest-quality wind sites shown in Table A.3. Since current wind development remains well within the first cost step, the cost of developing the lower-quality sites is one of the highly uncertain parameters in the analysis. The construction costs and wind quality could be worse or better than expected, resulting in a higher or lower LCOE. The classification system used to estimate the site quality uses a coarse set of filters accounting for wind speeds, terrain, and distance to transmission lines. The analysis uses GIS software, and on-the-ground site inspection could find less favorable conditions. Conversely, new turbine technologies could improve wind-capacity factors and the ability to develop low-quality sites. In the uncertainty analysis, we vary the cost-escalation rates in Table A.3 by 50 percent.

Recent work at the National Renewable Energy Laboratory (NREL) to develop the Wind Deployment System Model (WinDS) to simulate high levels of wind-power penetration shows much lower cost-escalation factors as capacity increases. Our analysis uses the base set of cost factors described earlier and varies the escalation factors through a considerable range. We believe that this approach captures the same range of potential costs implied by the more recent studies while also allowing for less favorable outcomes with much higher development costs.

Biomass

EIA assumes biomass electricity from IGCC power-generating systems. We assume that plant capital and nonfeedstock operating costs do not change as additional generating capacity is built but that feedstock costs do increase as greater amounts are required. The details behind the construction of biomass supply curves are presented when we discuss biofuel supply curves.

Co-firing and dedicated biomass-electricity plants will compete with other biomass-energy sources for available feedstocks and bid up the price of biomass. Therefore, the ultimate use of biomass electricity depends on assumptions about feedstock supply costs, conversion efficiency, and demand for biofuels. The biofuel model also includes co-production of electricity from biofuel plants.

Biomass co-firing also is constrained by the maximum amount of biomass that coal plants can mix into their fuel supplies and by the number of coal plants that could retrofit their plants. We assume that existing coal plants can use biomass to produce up to 15 percent

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[1] *Capacity factor* is the average amount of generation from a plant relative to its maximum potential output. The assumption of a constant capacity factor independent of location implies that wind quality is determined primarily by the average wind speed as opposed to wind duration.

of their output. This follows the maximum constraint that EIA uses in the NEMS model. We also assume that, at a maximum, half of existing coal plants can use co-firing (Robinson, Rhodes, and Keith, 2003). With these constraints, assuming that sufficient biomass feedstock supply is available, biomass co-firing can substitute for up to 7.5 percent of coal-fired generation that would be in place in 2025.

Geothermal

We use a site-specific study of potential geothermal resources in the western United States conducted by Sandia National Laboratories. In this study, Petty et al. (1992) estimated the costs of developing geothermal electricity from 43 potential sites in the western United States. We have aggregated their site-specific data into cost curves. Table A.4 shows the geothermal-resource data.

The analysis assumes a 0.95 capacity factor for geothermal generation, which is the estimate from the AEO 2006. EIA projects about 46,000 GWh of geothermal generation in the reference case for 2025, which uses most of the low-cost supply of geothermal resources. Additional generation from this source occurs at more-costly sites. We allow variation in geothermal costs by compressing and expanding the cost-curve increments by 25 percent. We used this level of variation in the cost-escalation factors to account for the significant uncertainty in the costs of this resource.

Several recent analyses of geothermal resources show different projected available capacity and costs. These assessments include new technologies that would allow development of deeper sources of geothermal energy. A recent study by the Massachusetts Institute of Technology (MIT) assessed enhanced geothermal systems (EGS), which cover noncommercial technologies that mine heat sources at greater depths than do current geothermal projects. MIT's study concluded that a large potential exists for EGS (up to 100 GW). Under its base-case assumptions, LCOEs from these projects can vary from about $0.10 per kWh up to $0.70 per kWh, depending on site-specific factors. Under a mature-technology case with technological improvement, EGS levelized costs can be competitive with fossil-fuel sources (MIT, 2006).

Several factors limit the application of the MIT work to this analysis. MIT assumed a time horizon to 2050. Subsequently, EGS would need substantial R&D and technological improvement to provide significant amounts of economic capacity by 2025. Second, because

Table A.4
Geothermal Supply Curve Data

Cost Level (2004 dollars per MWh)	Available Capacity (GW)	Potential Generation (GWh)
50	3.0	24,966
75	7.0	58,337
100	2.1	17,310
150	2.8	23,052
200	1.8	15,063
250	0.8	6,366
350	0.5	4,161

SOURCE: Petty et al. (1992).

EGS technologies are noncommercial by the definition used in the MIT report, the cost estimates are prone to underestimation (Merrow, Phillips, and Myers, 1981).

Two other recent analyses further illustrate uncertainties about geothermal capacity and costs. A study conducted for the Western Governors' Association (WGA) found that about 5.5 GW of capacity is available at a cost of less than $0.08 per kWh and up to 12 GW at costs up to $0.20 per kWh. The time frame for this analysis was 2015 and included only known geothermal sites. These estimates for capacity and costs are roughly comparable with the Petty 1992 study after excluding existing capacity (WGA, 2006a). Finally, Petty and Porro (2007) recently published an updated assessment of geothermal supply potential for potential use in EIA's NEMS model. This assessment includes traditional hydrothermal-vent technologies and newer technologies, such as EGS and co-production of geothermal electricity at oil and gas fields. They estimated more than 100 GW of potential capacity at costs of less than $0.08 per kWh (Petty and Porro, 2007).

In our analysis, we use the capacity estimates from the original Petty (1992) study excluding existing capacity. We then allow the range of cost-escalation steps to vary by 25 percent. This variation in cost steps accounts for the uncertainty in future development costs. The studies cited show potential for cost decreases in developing new sites with established technologies and using new technologies. We allow for higher potential costs to address greater-than-expected costs of developing marginal sites. Furthermore, we use the lesser capacity estimates from the Petty (1992) and WGA (2006a, 2006b) reports to account for the fact that the 2025 time frame limits the ability of new geothermal technologies to become competitive with existing technologies.

Solar Thermal

We use a relatively small quantity of potential solar-thermal capacity, which is assumed to be developed in the southwestern United States. For this resource, we assume that it can be developed at a uniform cost and then allow the magnitude of that cost to vary in the analysis. EIA's projection for solar-thermal electricity provides the baseline cost, and we allow it to vary within a range of –30 percent to +30 percent.

Our estimates of solar-thermal supply come from a recent analysis for WGA.[2] In 2004, WGA set a goal of increasing renewable-energy capacity in the region by 30 GW by 2015. A solar task force comprised of experts in the region assessed the potential for solar-thermal development in the region. In its analysis, it showed that substantial solar-resource potential exists (upward of 200 GW) that is near existing power lines and population centers. However, the global solar-power industry is constrained in production capacity. The WGA Solar Task Force analysis showed that, by 2015, the maximum production capacity is 13.4 GW (WGA, 2006b). Based on these supply constraints as assessed by solar-thermal proponents, we assumed a range of total capacity in the region by 2025 of 7–13 GW.

Incremental Cost of Renewables Substitution

The model calculates the cost of requiring additional renewable electricity in the electricity system by calculating the difference between marginal costs of renewable and nonrenewable

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[2] See WGA (undated) for participating governors.

resources. Our analysis assumes that, under a national renewables requirement, new renewable capacity first will displace the new, projected fossil-fuel and nuclear capacity. Therefore, part of the incremental cost of the policy is the difference between costs of the renewable capacity and projected nonrenewable capacity—namely, the 149 GW shown in Table A.2. The incremental cost calculation differs for firm power resources, such as biomass and geothermal; a fossil-fuel switching technology, such as biomass co-firing; and intermittent power resources, such as wind and solar. Table A.5 shows our assignment of different technologies to various categories based on their typical patterns of availability and use.

We assigned power-plant technologies to one of the three categories based on their operating characteristics and relative costs. Base-load technologies generally have low operating costs and high investment costs. The plant operator can vary their power output, but a fairly long time is required to attain large swings in power output. A base-load–type plant is most efficiently and cost-effectively operated near its maximum rated capacity for long periods. In contrast, peak-load technologies have higher operating costs but can be quickly dispatched to meet electricity demand during peak periods. Intermittent technologies produce electricity when the resource is available. Therefore, their output is variable and sometimes stored or supplemented by a peak-load technology that can balance the variable output.

Firm Power Technology

Firm power capacity can substitute for nonrenewable capacity on a one-for-one basis. Therefore, 1 MW of biomass capacity would displace all the capital and fuel costs from 1 MW of a nonrenewable electricity source. The incremental cost then becomes the difference in the levelized costs of the renewable electricity source and the nonrenewable source that it displaces. Table A.6 shows the cost breakdown, using EIA's cost projections, for a biomass plant and several potential nonrenewable resources.

The Capital charge through Transmission rows in Table A.6 show EIA's projected costs for each technology by type of cost. The Levelized cost row is the sum of these costs, or

Table A.5
Electricity Power-Plant Assignments

Technology Type	Plant Assignment
Base load	Pulverized coal
	Advanced coal (IGCC)
	Advanced combined-cycle gas
	Conventional combined-cycle gas
	Dedicated biomass
	Geothermal
	Nuclear
Peak load	Conventional combustion turbine
	Advanced combustion turbine
Intermittent	Wind
	Solar

Table A.6
Cost Comparison for Firm Power

	Power (2004 dollars per MWh)					
Cost	Biomass	Advanced Nuclear	Conventional Combined Cycle	Advanced Combined Cycle	Advanced Coal	Pulverized Coal
Capital charge	30.86	42.23	11.65	11.08	29.9	25.97
Fixed operation and maintenance (O&M)	6.68	7.84	1.49	1.4	4.73	3.37
Variable or fuel[a]	18.69	6.72	41.38	38.61	14.85	18.74
Transmission	3.44	2.8	2.9	2.9	3.49	3.49
Levelized cost	59.66	59.59	57.43	53.99	52.97	51.56
Incremental cost of substituting biomass	0	0.07	2.23	5.67	6.69	8.1

[a] Fuel costs are those assumed in EIA (2006a). In our model, biomass, coal, and natural gas costs are recalculated as the requirement for renewable energy increases.

LCOE, for each technology. The Incremental cost of substituting biomass row shows the difference between the incremental cost of each technology and the renewable technology (biomass power). The model projects new fuel costs for biomass, coal, and natural gas as the policy requirement increases the amount of renewable energy in the system. In this process, biomass-fuel costs increase as biofuel and electricity producers compete for the same feedstock and fossil-fuel (coal and natural gas) prices change as demand for these fuels decrease. An important caveat for Table A.6 is that it reflects baseline costs from EIA. As already noted, we address other possible baseline costs in our sensitivity analyses.

Fuel-Switching Technology

The preceding section showed the incremental cost calculation for firm power technologies. The converse case is a pure fuel-switching (fossil fuel–saving) technology, such as biomass co-firing. With biomass co-firing, a coal-fired plant is retrofitted to feed a mixture of biomass and coal into the boiler. The renewable fuel does not offset capacity and displaces only the fuel used in the coal plant. The incremental cost of a fuel-saving technology is the levelized cost of the capital and fuel costs of co-firing minus the fuel cost in the coal plant. We use EIA's cost assumptions for retrofitting a coal plant of $237 per kW of capacity, and the fuel cost is determined endogenously by the model using the biofuel supply curves.

Intermittent Technology: A Hybrid of Firm Power and Fuel Switching

The incremental cost calculation for intermittent power sources is a combination of the firm power and fuel-saver calculations. We assume that wind and solar power are taken into the system as available and decrease the use of nonrenewable resources. In this sense, they are a fuel-saving technology. An important assumption is how these intermittent sources substitute for nonrenewable capacity. One possible assumption is that intermittent sources displace no nonrenewable capacity. In this case, when wind power is available, it reduces fuel consumption at the marginal generating unit, and it is a pure fuel-saving technology. Another assumption is that intermittent resources can displace some portion of new generating capacity, to which we refer as a wind-capacity credit. If we assume that wind has a capacity credit of 20 percent, then 100 MW of wind would displace 20 MW of new, nonrenewable capacity. In the incremental cost calculation, the incremental cost would become the levelized cost of wind minus the fuel costs of displaced generation and 20 percent of the nonfuel capital costs for displaced new fossil investment. Because combustion turbines are typically used to balance the intermittent supply, we assume that wind and solar will not displace any of the peak-period capacity. To make this calculation, we have to make assumptions about the marginal nonrenewable resource in different parts of the load curve and the distribution of intermittent power across the load curve.

We use the same assumptions about marginal resources across the load curve for wind and solar. During the base period, intermittent resources substitute for pulverized-coal generation. In the shoulder, they substitute for advanced combined-cycle plants. In the peak, they substitute for conventional combustion-turbine generation. The model is not capable of selecting these resources endogenously, so they are programmed by assumption. The assumptions were based on two factors: levelized costs of resources in each period and the available capacity. In a simplified least-cost minimization, the marginal resource in each period is the one with the highest marginal costs subject to capacity constraints. When iterating through the model, the most expensive nonrenewable resources (i.e., advanced nuclear and gas-fired capacity) are either displaced by other renewable-energy sources or removed by conservation. In most runs of the model, the remaining nonrenewable resources in the base and shoulder periods are pulverized-coal plants and advanced combined-cycle gas plants. In the peak period, conventional combustion turbines are the most expensive generation source and the marginal supply.

Another assumption in the incremental cost calculation for intermittent sources is the distribution of generation over the load curve. For wind, we did not have data available on the temporal distribution of wind generation and assume that wind generation matches the distribution of the load curve. We assumed that 70 percent of total generation occurs during the base period, 25 percent during the shoulder, and 5 percent in the peak. This assumption matches the load curve assumed in RFF's Haiku electricity model (Paul and Burtraw, 2002). For solar thermal, our capacity estimates are for the southwestern United States, and recent analysis shows a high correlation between the solar resource and peak demand (Perez et al., 2006; Cohen, 2005). We thus place more weight in the distribution on the peak and shoulder periods. For solar, 40 percent of generation occurs in the base, 30 percent in the shoulder, and 30 percent in the peak.

Tables A.7 and A.8 illustrate how we use technology-cost assumptions to calculate the incremental costs of wind and solar-thermal power. We show the incremental cost calculations for two assumptions about capacity credit. We assume a range of 0 to 40 percent for capacity credit.

Table A.7 displays the component costs for wind and solar-thermal technologies at the EIA baseline-cost level. In the 0 percent capacity-credit case, they displace fuel only from the three nonrenewable technologies. In the 20 percent capacity-credit case, they displace the full fuel costs but only 20 percent of the nonfuel costs.

Table A.8 shows the incremental costs for wind and solar-thermal power for two values of the capacity credit. These figures are calculated by taking the difference in the levelized cost

Table A.7
Sample Cost Comparison for Intermittent Technologies

			Capacity Credit (2004 dollars per MWh)					
			0%			20%		
Cost	Wind	Solar Thermal	Pulverized Coal	Advanced Combined Cycle	Conventional Combustion Turbine	Pulverized Coal	Advanced Combined Cycle	Conventional Combustion Turbine
Capital charge	42.79	106.06	0	0	0	5.19	2.22	0.00
Fixed O&M	8.45	19.39	0	0	0	0.67	0.28	0.00
Variable or fuel	0	0	18.74	38.61	63.95	18.74	38.61	63.95
Transmission	6.91	9.32	0	0	0	0.70	0.58	0.00
Total	58.15	134.77	18.74	38.61	63.95	25.31	41.69	63.95

Table A.8
Sample Incremental Costs for Intermittent Technologies

	Incremental Cost (2004 dollars per MWh)	
Capacity Credit %	**Wind**	**Solar Thermal**
0	32.18	96.51
20	26.82	92.96

of wind and solar thermal and the total displaced costs of nonrenewable technologies weighted by the distribution of wind or solar-thermal power across the load curve (wind: 70 percent base, 25 percent shoulder, and 5 percent peak; solar thermal: 40 percent base, 30 percent shoulder, and 30 percent peak).

Specifying Demand and Supply Elasticities for Fossil Fuels and Electricity

The electricity model contains a basic supply-and-demand model of the domestic coal and natural gas markets. We use this to project how changes in electric-utility demand for natural gas and coal affect prices. Both fuel markets follow the same setup, but we parameterize the models to account for differences in the markets.

We use the following general equation for direct demand for natural gas:

$$Q_d = B \times P^{-e},$$

where Q_d is the quantity demanded, B is a constant derived from EIA data, P is the market price, and e is the (absolute) price elasticity of demand.

For market supply of natural gas, we use the following general equation:

$$Q_s = A\left(P - P_{\min}\right)^n,$$

where Q_s is quantity supplied, A is a constant derived from EIA data, P is the market price, P_{min} is a minimum supply price, and n is a parameter determined by the assumed elasticity of supply. A range of values is considered for the elasticity parameters, as discussed later.

The equilibrium condition for the natural gas market is

$$Q_s = Q_d^{elec} + Q_d^{nonelec},$$

which accounts for natural gas demand in the electric and nonelectric utility sectors. The constant values are estimated at the equilibrium pairs of demand and price projected in AEO 2006 for 2025 and shown in Table A.9.

The values shown in Table A.9 come from EIA (2006b, Table 13). The price for total supply is the average lower-48 wellhead price for natural gas, and the other prices are for natural gas delivered to consumers. We discuss in the report text and summarize later the assumptions made on the elasticities.

Table A.9
Natural Gas Market Initial Values

Market	Quantity (quads)	Price (2004 dollars per 1,000 ft^3)
Total supply[a]	25.75	5.43[b]
Electricity	7.23	6.02
All sectors	18.52	7.69

[a] Excludes plant and lease fuels.

[b] Projected average lower-48 wellhead price in 2025.

The approach for coal is similar, except that nonutility uses are more limited. The initial demand for coal by electric utilities is 27.54 quads, and the initial price is $1.44 per million BTUs.

These models of fossil-fuel supply and demand are used to project new fossil-fuel prices in response to changes in electric-utility demand for fuels. We also project changes in nonutility demand for fuels and the resulting expenditures. In general, as renewable energy substitutes for coal and natural gas consumption in electric utilities, the market price declines and nonelectric utility demand increases.

To represent electricity demand, we also use a similar functional form:

$$Q_d^{elec} = A \times P_{elec}^{-e},$$

where Q_d^{elec} is quantity of electricity demand, A is a constant estimated with EIA projections for 2025, P_{elec} is the average retail price of electricity estimated in the model, and e is the (absolute) price elasticity of demand. We estimate the A constant using an assumed price elasticity of demand and the equilibrium price/quantity pair from the AEO 2006 for 2025. The initial electricity demand is 4.945 trillion kWh, and the initial price is $0.074 per kWh.

Assumptions About Biomass and Biofuel Costs and Capacities

As described in Chapter Two, the biomass supply model combines assumptions about biomass feedstock capacity, feedstock cost, conversion efficiency, and cost of building and operating production plants to generate marginal cost curves for biofuels. In this section, our focus is on the construction of these curves for ethanol derived from cellulosic biomass, since that approach to biofuels has received the most attention so far in policy discussions. However, we also allow for the possibility of biofuels through thermo-chemical conversion—namely, biomass gasification followed by synthesis of transportation fuels using either the FT or methanol-to-gasoline (MTG) approach.

Feedstock-Production Capacity and Cost

Future biofuels can potentially come from numerous feedstocks, including agricultural residues, such as corn stover, as well as forestry residues and various dedicated energy crops. The current primary candidates for dedicated energy crops are switchgrass and short-rotation woody crops, such as hybrid poplar and willow trees (Perlack et al., 2005). The potential production capacity for these feedstocks depends on assumptions about future agricultural yields, new harvesting technologies, land-use conversion, and constraints on harvesting residues to prevent erosion.

Several recent analyses have estimated potential biofuel supply and show a large range in potential supply and costs. In the 2006 version of the NEMS model, EIA used a maximum capacity of 433 million tons of biomass at costs of less than $90 per ton. EIA has recently contracted with researchers at the University of Tennessee (UT) to analyze its current capacity projections and supply alternative estimates, and these updated estimates were used in EIA's recent analysis of a 25 percent renewable-energy requirement (EIA, 2007). In a 1999 study on potential biomass supply, the Oak Ridge National Laboratory developed a set of biomass supply curves with a maximum potential annual supply of 510 million tons at costs of less than $90 per ton. In a 2005 study sponsored by DOE and USDA, the research team projected several scenarios of future crop yields, harvesting technologies, and land-use conversion. Their analysis showed that, under their range of assumptions, agricultural lands could yield from 400 million tons to 1 billion tons of biomass annually. Forest lands could provide up to 370 million tons of additional biomass (Perlack et al., 2005).

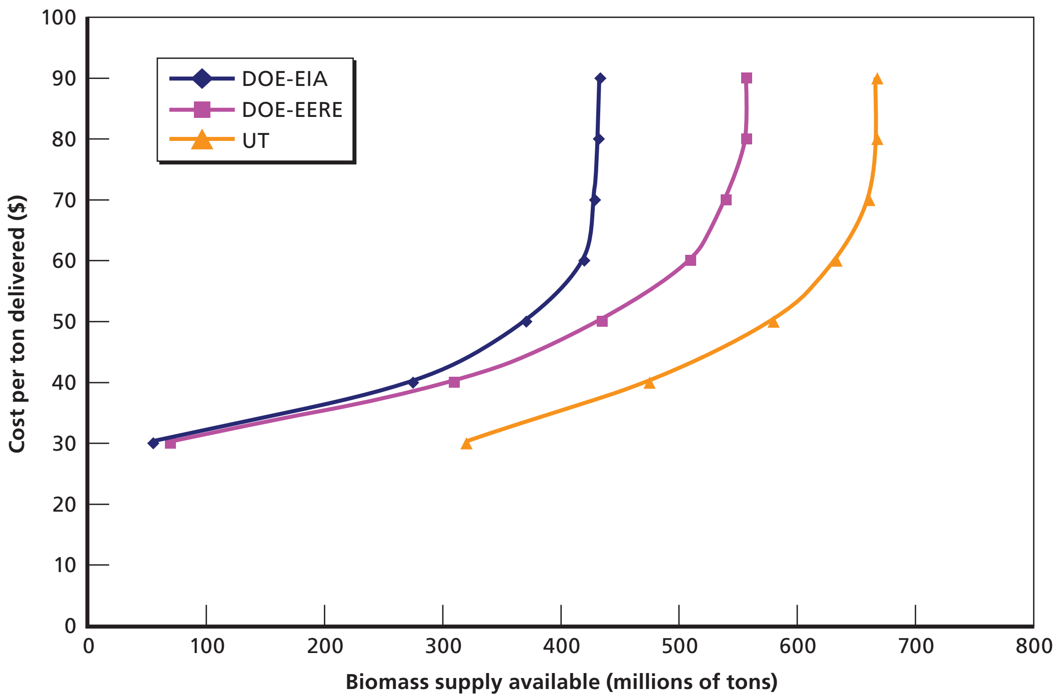
There are several important caveats to the DOE/USDA analysis. The first is that the study used a time horizon of the mid-21st century. The analysis did not attempt to project how the forestry and agricultural industries would reach these targets. Therefore, the estimates provide limited guidance on what these industries could supply by 2025. In addition, the supply projections do not estimate the costs of delivering this supply to a biofuel refinery or a power plant. Consequently, even if industry could supply this level of biomass capacity, consumers may not be willing to pay the price of the fuels derived from it.

The preceding discussion shows the range of potential biomass feedstock capacity from several recent studies. However, the key question for our analysis is how much industry can supply by 2025 and at what levels of cost. We have used three recent estimates of biomass supply as a basis for our range of assumptions, which are shown in Figure A.3.

The range of costs in these curves begins at $30 per ton of delivered biomass feedstock and rises up to $90 per ton. The cost steps are in $10-per-ton increments. The first curve is the assumptions used by EIA in the 2006 NEMS model. This curve reaches maximum capacity at 433 million tons and has a greater percentage of biomass in the higher cost levels. The second estimate is from EERE. The total supply of biomass in this curve is 557 million tons, and the distribution of biomass in the cost levels is similar to those of the EIA estimate. The final biomass supply curve comes from a group of researchers at UT. This curve has a maximum supply of 667 million tons, with a greater proportion of supply in the lower cost levels. All of these supply curves include biomass from the following sources: agricultural residues, energy crops, forest residues, and urban wood waste and mill residues. They do not, however, include biomass from food crops, such as corn used to produce ethanol.

In our analysis, we assume that a range of biomass supply from 450 million tons to 1 billion tons is available at costs of up to $90 per ton. We call this the *low-cost biomass supply* and assume that this supply comes from waste residues and marginal lands not currently in production. Other sources of biomass are also available. Land currently used for agriculture, pasture, or forestry can be converted to producing energy crops. We assume that biomass from these supplies is the highest-cost supply in the curve and comprises a backstop for biomass supply. That is, at a certain price, an arbitrarily large amount of biomass is available that is sufficient to fulfill demand beyond the supplies available from wastes and marginal lands. We assume

Figure A.3
Biomass Supply Curve Estimates



NOTE: EERE = DOE Office of Energy Efficiency and Renewable Energy.
RAND *TR384-A.3*

a range of potential costs for backstop supplies of $90 to $200 per ton. We allow for a wide range because of the great uncertainties in the costs of profitably converting land in future agricultural markets. Some basic analysis using current estimates of land rents and production costs suggests that this is a feasible range.

We established the lower end of our range for land-use conversion costs based on estimates of biomass feedstock production costs from ongoing RAND research and recent USDA analysis on land values (National Agricultural Statistics Service and Agricultural Statistics Board, 2007). The latter report on land values and cash rents estimates that the average cash rent for cropland in the northern plains (including Kansas, Nebraska, North Dakota, and South Dakota) is $58 per acre and $30 per acre in the southern plains (including Oklahoma and Texas). We focus on these regions because switchgrass is a grass native to these areas and they have considerable amounts of crop- and pastureland. For these reasons, they could produce a large amount of biomass feedstock under a 25 percent renewable-energy requirement. Assuming a crop yield of 5 tons per acre, the costs for renting land in these regions to produce biomass feedstock range from $6 to $12 per ton of feedstock. Recent RAND analysis has estimated that the production and transportation costs for switchgrass (excluding land rent) were approximately $70 per ton (Ortiz, 2008). Summing this estimate with the land-rent estimate yields a range of $76 to $82 per ton in these regions. We increase the lower-bound estimate to $90 per ton to account for potential underestimation of these costs.

For the upper end of the assumed range, we begin with land-rent estimates for high-cost cropland. The highest cash-rent estimate in the USDA report is $340 per acre for irrigated cropland in California. This land, in principle, could be converted into biomass production, especially because it is near major markets for biofuels on the West Coast. The USDA estimate translates into a land-rent cost of about $70 per ton, assuming a yield of 5 tons per acre. Using the same production costs assumed already, we estimate that the total cost of producing biomass feedstock is $140 per ton. To allow for the potential for higher costs, we set the upper end of the range at $200 per ton.

An important uncertainty unaccounted for in these estimates is that the rising demand for biomass under a 25 percent renewable-energy requirement could increase agricultural cash rents above the levels in the USDA report. The USDA report already shows that average cash rents have increased every year from 1998 to 2007, with the largest increase from 2006 to 2007. Massive new demand for biomass could accelerate this trend of increasing land rents.

We use one more parameter to characterize the biomass feedstock supply. We assume a range of feedstock distributions indicating the fraction of the low-cost supply available at different costs. This range of distributions is anchored at one end by the distribution of the EIA curve and at the other end by the curve from UT. These distributions give the percentage of total supply within each of the cost levels from $30 per ton to $90 per ton. With these two characteristics, low-cost biomass capacity and its distribution by cost, we can create a range of potential supply curves from relatively limited and expensive supply to abundant and inexpensive supply. Beyond these supplies, the biomass-backstop price reflects the prices needed to induce land conversion for energy-crop production.

Bioethanol-Plant Yields, Capital, and Operating Costs

In this analysis, we have assumed that corn-based ethanol is constrained to the total in AEO 2006 for 2025 (0.99 quads). The remaining demand for biofuels comes from three resources: cellulosic ethanol, biodiesel, and biomass liquefaction through the FT or MTG method. Biodiesel is constrained to a small fraction of the total requirement (following EIA's capacity assumption); therefore, cellulosic ethanol and derived fuels fulfill the majority of biofuel demand. Because these technologies are not yet in a commercial state,[3] there is significant uncertainty in the future costs of these technologies.

We break the biofuel costs into two components:

$$\begin{aligned}\text{biofuel cost}\left(\$ / \text{ton feedstock}\right) &= \text{feedstock cost}\left(\$ / \text{ton feedstock}\right)\\ &+ \text{nonfeedstock cost}\left(\$ / \text{ton feedstock}\right),\end{aligned}$$

where nonfeedstock costs include capital costs, variable operating costs, and co-product value. These cost components are in units of dollars per ton of feedstock. This allows us to vary the conversion yield (gallons of biofuel per ton of feedstock) independently. To convert these costs into unit of dollars per gallon, we divide by the production yield.

We use a range of costs to represent different potential future states of these technologies. On the lower end of the range, we use an estimate from Aden et al.'s 2002 report sponsored by

[3] DOE recently accepted bids on six pilot plants to produce cellulosic ethanol. FT synthesis technology dates back to World War II, and several coal and natural gas–fueled plants exist today. FT plants fueled entirely by biomass are still in a precommercial stage. One of these DOE pilot plants will produce *syngas*, which is an intermediate step to producing liquid transportation fuels.

NREL. This report described the cost of producing cellulosic ethanol for an "*n*th-of-a-kind" plant, which represents a new plant that benefits from efficiencies gained from building and operating a number of several previous plants. The report reflects several optimistic assumptions by the NREL team about reductions not only in delivered feedstock costs but also in the cost of enzymes and capital costs.

Assuming cost reductions due to learning is an accepted practice in projecting future costs. However, one of the vulnerabilities in making such projections is the reliability of the baseline cost calculation. Earlier RAND research has shown that early cost estimates of new technologies tend to underestimate the true cost of the initial plants (Merrow, Phillips, and Myers, 1981). This occurs because the initial cost estimates use low-definition engineering designs that do not foresee all of the details in a new energy technology. Therefore, when initial plants are built, actual costs almost always exceed projected costs. The RAND analysis showed that early estimates understate the costs of a first-of-a-kind plant by 25 to 50 percent. This underestimate is propagated forward in time when the preconstruction estimates are used as the base for *n*th-of-a-kind plant costs.

Because of this tendency to understate the costs of new technologies prior to the realization of actual commercial-scale investment experience, we treat the Aden et al. (2002) estimate as a lower (most favorable) bound, and we develop an upper-bound estimate using estimates of current technology cost while allowing for the effect of some cost-reducing by 2025. To derive this estimate, we start with a recently published paper by Solomon, Barnes, and Halvorsen (2007) for a first-of-a-kind cellulosic-ethanol plant built today. We revised upward the estimate because it assumed a 100 percent capacity factor, and, in our judgment, it did not provide enough of a capital-cost contingency to reflect typical capital costs for a first-of-a-kind plant. We recalculated the capital costs to include a 25 percent cost contingency and applied a 90 percent capacity factor. We then allowed for some learning to reduce costs for later plants as production scales up to meet the requirement.

Table A.10 displays a breakout of the cost assumptions for the Aden et al. (2002) study; the original cost estimate from Solomon, Barnes, and Halvorsen (2007); and the revised Solomon estimate that we use. The table shows that, under the various underlying assumptions discussed previously, the gasoline gallon–equivalent cost of ethanol ranges from \$1.57 to \$3.74. Note, however, that these figures are based entirely on feedstock costs drawn from the two papers in question. In our uncertainty analysis, we combine ranges of nonfeedstock costs based on these two studies with our own analysis of alternative-feedstock costs discussed earlier.

Table A.10 shows figures for the refinery's cost for biomass delivered (*feedstock cost*), cost of materials (primarily enzymes) and energy in converting biomass to a fuel (*conversion cost*), amortized capital cost of the refinery, and a co-product credit from producing electricity that is sold to the electrical grid. The revised estimates have blanks because the new cost estimates were not disaggregated into these categories.

In our analysis, we break the total cost of biofuels into a production cost and a feedstock cost. The production cost combines the conversion costs, capital costs, and co-product credits, and we assume a range of possible values for this cost. The feedstock cost is derived using a biomass supply curve and an assumed conversion efficiency. We thus further modified the cost-estimate data shown in Table A.10 using various assumptions about conversion efficiency, to independently parameterize production costs, conversion efficiency, and feedstock supply costs.

Table A.10
Biofuel-Cost Assumptions (2004 dollars per gallon of ethanol, except as indicated)

Cost	Aden et al. (2002)	Solomon, Barnes, and Halvorsen (2007)	Revised Solomon, Barnes, and Halvorsen (2007)	Revised Solomon, Barnes, and Halvorsen (2007) with Learning
Feedstock	0.34	0.66	0.66	0.66
Conversion	0.33	0.67	—	—
Capital	0.51	0.82	—	—
Subtotal: nonfeedstock	0.84	1.49	1.93	1.49
Co-product credit	–0.09	–0.08	—	—
Total ($/gallon of ethanol)	1.08	2.08	2.59	2.15
Total ($/gallon of gasoline equivalent)	1.57	3.01	3.74	3.10

NOTE: The revised estimates have blanks for those categories into which the new cost estimates were not disaggregated.

In Table A.10, the cost estimates are in units of dollars per gallon. We convert the non-feedstock-production costs into units of dollars per ton of biomass. This conversion lets us independently parameterize production costs, conversion efficiency, and feedstock supply, yet still maintain a relationship between conversion efficiency and capital cost. In the Aden et al. (2002) estimate, the nonfeedstock costs are $0.74 per gallon, and the assumed conversion yield is 90 gallons per ton. The modified nonfeedstock-production cost is then $67 per ton of biomass. The nonfeedstock production cost per gallon for the revised Solomon, Barnes, and Halvorsen estimate with learning is double the lower-end value from Aden et al., so assuming the same 90-gallon-per-ton yield gives us an upper-bound nonfeedstock cost of $134 per ton of biomass feedstock.[4]

In our uncertainty analysis, we assume a range of conversion efficiencies between 80 gallons per ton and 100 gallons per ton (dry basis). Again, with no commercial-scale plants in production today, this value requires speculation on the future progress in biofuel technology. At the low end of the range, 80 gallons per ton represents a modest improvement in efficiency from estimates of efficiency for proposed pilot plants. In a recent DOE solicitation for cellulosic-ethanol pilot plants, the proposed plants ranged in efficiency from about 40 gallons per ton to more than 90 gallons per ton (DOE, 2007). Table A.11 displays the projected plant capacities and feedstock rates for these specific, proposed plants. The upper end of the range in our study, 100 gallons per ton, is based on our judgment of the maximum level achievable by 2025. We assume that the very aggressive technology target for 2030 of 116 gallons per ton (Sheehan, 2007) is not reachable by 2025.

The following steps show how we combine this information to construct biofuel supply curves. The uncertain variables in the analysis are total feedstock supply, feedstock distribution, nonfeedstock-production cost, and conversion efficiency. Table A.12 shows the quantity

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[4] This figure is actually slightly too low, since the Solomon, Barnes, and Halvorsen study was based on a 95-gallon-per-ton yield.

Table A.11
Projected Conversion Yields for Proposed DOE-Funded Ethanol Plants

Feedstock	Nameplate Capacity[a] (millions of gallons per year)	Actual Capacity[b] (thousands of gallons per day)	Feedstock Input (tons per day)	Conversion Yield (gallons per ton)
Agricultural residue	11.4	28.1	700	40.2
Urban waste	13.9	34.3	770	44.5
Landfill waste	19	46.8	700	66.9
Agricultural residue	31.25	77.1	842	91.5
Agricultural residue	18	44.4	700	63.4
Wood residue	40	98.6	1,200	82.2

SOURCE: DOE (2007).

NOTE: Each row reflects a specific, proposed plant, of which three were to use agricultural residue.

[a] *Nameplate capacity* refers to the maximum theoretical output rate, given the plant's design.

[b] Assumes 90 percent capacity factor.

Table A.12
Sample Biofuel Supply Curve Quantity Estimates

Feedstock-Cost Levels ($ per ton)	Biomass Quantities (millions of tons)	Ethanol (billions of gallons of ethanol)	Ethanol (billions of gallons of gasoline equivalent)
30	57.2	5.14	3.55
40	228.3	20.55	14.18
50	99.4	8.94	6.17
60	51.1	4.60	3.18
70	9.3	0.84	0.58
80	3.1	0.28	0.19
90	1.6	0.14	0.10

estimates of the supply curve using EIA's assumptions about total feedstock and distribution and the conversion yield assumed in the Aden et al. (2002) study (90 gallons per ton).

Table A.13 shows the cost estimates using the assumed conversion yield of 90 gallons per ton and the two nonfeedstock cost estimates ($67 and $134 per ton of feedstock) described in the text.

Table A.12 uses the assumed conversion efficiency to convert the biomass feedstock supply curve into the available quantities for a biofuel supply curve. Table A.13 combines the conversion efficiency and nonfeedstock information to estimate the wholesale costs for biofuels. Also note that biofuel costs can rise above the levels shown when competition bids up the price of biomass feedstock beyond the upper limit of production costs considered in the supply curves.

Table A.13
Sample Biofuel Supply Curve Price Estimates

Feedstock Cost		Wholesale Cost (2004 dollars per gallon of ethanol)		Wholesale Cost (2004 dollars per gallon of gasoline equivalent)	
Level ($/ton)	Cost ($/gallon)	Aden et al. (2002)	Revised Solomon, Barnes, and Halvorsen (2007) with Learning	Aden et al. (2002)	Revised Solomon, Barnes, and Halvorsen (2007) with Learning
30	0.33	1.08	1.82	1.56	2.64
40	0.44	1.19	1.93	1.72	2.80
50	0.56	1.30	2.04	1.88	2.96
60	0.67	1.41	2.16	2.04	3.12
70	0.78	1.52	2.27	2.20	3.28
80	0.89	1.63	2.38	2.37	3.44
90	1.00	1.74	2.49	2.53	3.60

Biomass Liquefaction Through Biomass Gasification

Cellulosic ethanol is not the only technology that can potentially produce transportation fuels from cellulosic biomass. Gasifying biomass and producing transportation fuels using either the FT or MTG method is an alternative technological pathway. The FT approach currently operates at commercial scale but using either coal or natural gas. The MTG approach is also commercial but only on natural gas. An advantage of both approaches is that the fuels produced are essentially identical to conventional gasoline and diesel. These fuels could be distributed using the existing infrastructure for the storage and delivery of finished petroleum products. Moreover, using these fuels would require no major engine modifications, such as the flex-fuel modifications needed to use high-level blends of ethanol, and would result in no fuel-economy penalties (in contrast to ethanol-blended fuels).

No commercial-scale biomass-liquefaction plants using thermo-chemical conversion operate today, and the commercial potential of this technology over the next 20 years is uncertain. The AEO 2006 cites cost estimates for this technology in a similar range for cellulosic ethanol. One estimate of today's production costs was $3.35 per gallon, decreasing to $2.43 per gallon by 2020. The crude oil–equivalent price of these estimates is in the high $80-per-barrel range (EIA, 2006a). When looking at the AEO 2006 estimates for cellulosic-ethanol production, we see that production in 2025 above the level required in the 2005 Energy Policy Act (P.L. 109-58) occurs only in the high–oil-price case when oil prices approach the $80-per-barrel level. This suggests overlapping ranges of uncertainty in production costs for cellulosic ethanol and biofuel produced through thermo-chemical conversion.

With the level of uncertainty in the cost estimates for these technologies, we assume agnostically that the mix of biofuels produced to meet a 25 percent renewables policy requirement is split evenly between cellulosic ethanol and thermo-chemical conversion. We further assume that the mix of fuels from thermo-chemical conversion is two-thirds diesel and one-third gasoline. With these assumptions, the resulting mix of biofuels matches the current mix of transportation fuels of approximately two-thirds gasoline and one-third diesel.

We acknowledge that these are strong assumptions about the potential of these technologies. But due to the significant uncertainties in all the technologies, current cost projections do not provide the basis to develop supply curves with the level of precision required to estimate how large a share each technology would gain in a future biofuel market. Furthermore, assuming that one technology would progress at the expense of the other could result in a situation in which the majority of the biofuel requirement is met by producing fuels primarily for the gasoline or diesel market. This result introduces complicating details into the analysis of how diesel consumers might cross-subsidize ethanol production to meet a renewable-fuel requirement in both the gasoline and diesel markets. Our assumptions focus the analysis on several of the key factors that drive how this renewables requirement generally could affect energy expenditures. Those include future technology costs relative to conventional fuels, conversion efficiencies, and potential biomass feedstock capacity.

Biodiesel

We include biodiesel in this analysis and develop supply curves based on the documentation provided in EIA's NEMS model. EIA allows a total of 200 million gallons of biodiesel from soybean oil and 270 million gallons from yellow grease. This total is approximately four times the amount of biodiesel production in 2005 (NBB, undated).

EIA projects biodiesel costs based on the feedstock, capital, and operating costs minus a co-product credit for producing glycerin. The main variable cost is the feedstock. EIA uses USDA projections for the price of soybean oil to estimate baseline feedstock costs. Soybean prices are also a function of biodiesel demand, and EIA uses a basic relationship derived from a USDA study estimating how a renewable-fuel standard would affect soybean prices (USDA, 2002; Radich, 2004). EIA models yellow-grease prices as a function of soybean prices based on the results of a linear-regression model (yellow-grease price $= 0.49 \times$ soybean oil price). Table A.14 displays its cost assumptions for the base level of feedstock prices.

EIA assumed (based on the USDA projection) that soybean oil costs \$0.305 per pound and the conversion efficiency is 7.7 lb per gallon. The estimated change in soybean oil–feedstock prices due to biodiesel production is \$0.003 per gallon of soybean oil per million gallons of biodiesel produced (in 2004 dollars) (USDA, 2002; Radich, 2004). This estimate of the impact of biodiesel production on soybean-oil prices indicates that producing the full 200 million gallons of biodiesel would raise soybean-oil prices by \$0.60 per gallon of soybean oil (\$0.08 per pound using the assumed conversion efficiency).

Table A.14
Breakdown of Biodiesel Cost Assumptions

Cost	Yellow Grease–Derived Wholesale Price (2004 dollars per gallon)	Soybean Oil–Derived Wholesale Price (2004 dollars per gallon)
Capital	0.14	0.14
O&M	0.46	0.46
Feedstock	2.35	1.15
Co-product	–0.16	–0.16
Total	2.79	1.59

SOURCE: EIA (2006c).

Modeling Petroleum-Market Prices

We use a simple representation of the world crude-oil market to model how changes in U.S. demand for crude oil due to the renewables requirement affect world oil prices, which then affect the price of gasoline and diesel. This demand-and-supply model follows a similar structure to the demand-and-supply model described earlier for the natural gas and coal markets. Oil demand is described by the following equation:

$$Q_d^{oil} = A \times P_{oil}^{-e},$$

where Q_d^{oil} is oil demand from a consumer, P_{oil} is the world oil price, A is a constant estimated with EIA projections, and e is the absolute price elasticity of demand. The supply equation is

$$Q_s^{oil} = B\left(P - P_{\min}\right)^n,$$

where Q_s^{oil} is the quantity of oil supplied by a producer, B is a constant derived from EIA projections, P is the world price of oil, P_{min} is a minimum price to supply oil, and n is a parameter determined by the assumed supply elasticity of oil. The following equilibrium condition applies in this model:

$$Q_s^{oil} = Q_d^{U.S.\ trans} + Q_d^{U.S.\ nontrans} + Q_d^{rest\ of\ world}.$$

In other words, world oil supply must equal the demand from the U.S. transportation-demand sector, U.S. nontransportation demand, and demand from the rest of the world. We parameterize the three demand equations using the equilibrium quantity and price pairs from EIA's AEO 2006 projection for 2025 in the reference case. Table A.15 displays these values.

Table A.15 shows the initial values used in the petroleum-market models. The price information refers to imported crude oil, and all of the figures are EIA's projection for 2025.

We readily acknowledge that the representation of world oil supply glosses over numerous issues related to the market power of large petroleum-exporting countries and objectives

Table A.15
Petroleum-Market Initial Values: AEO 2006 Projections for 2025

Projection	Quantity (millions of barrels per day)	Price (2004 dollars per barrel)
World supply	110.87	47.99
U.S. total[a]	26.12	47.99
U.S. transportation	18.59	47.99
U.S. nontransportation	7.46	47.99
EIA discrepancy	0.07	—
Non-U.S. demand	84.58	47.99

SOURCE: EIA (2006b, Tables 11, 12, 20).

[a] 0.07 million–barrel-per-day discrepancy from EIA added to total.

other than discounted net present value maximization for state-influenced producing companies (e.g., revenue targets for debt service, financing current consumption, maintaining long-term economic sustainability). By looking at a range of supply-elasticity values in addition to demand elasticities, we can show how U.S. crude-oil demand displacement by biofuels might affect the world price of crude oil under different degrees of tightness or looseness of supply, without linking those conditions back to different assumptions about supplier behavior. One task for future research is the coupling of our framework for biofuels with a more complicated model of the world oil market, as for example in Bartis, Camm, and Ortiz (forthcoming).

With this supply-and-demand model, we can calculate world oil price response to changes in U.S. demand. The prices of retail gasoline and diesel are then a markup on the price of oil to account for refining, marketing, and transportation costs, as well as state and federal taxes. These markups are based on EIA projections. Table A.16 shows their values.

Transportation-Energy Demand

We model transportation-energy demand using the same aggregate demand equation as in the markets for natural gas, coal, and electricity. The equation constant is estimated using equilibrium values from the AEO 2006 reference case in 2025, which are shown in Table A.17.

Table A.17 shows initial gasoline and diesel demand for the three sectors of the transportation-fuel market included in this analysis. We selected these sectors because they account for nearly all current biofuel demand and comprise almost 80 percent of total transportation-energy demand.

Table A.16
EIA 2025 Projections of Petroleum-Product Prices

	Price (2004 dollars per gallon)	
Factor	**Gasoline**	**Diesel**
Oil price	1.14	1.14
Wholesale price	1.53	1.52
State taxes	0.24	0.21
Federal taxes	0.11	0.14
Retail price	2.13	2.07

SOURCE: EIA (2006b, Table 100).

Table A.17
Initial Values for Motor Transportation–Fuel Demand Values (quads)

Vehicle	Gasoline	Diesel
Light duty	20.55	0.86
Commercial light trucks	0.8	—
Freight trucks	0.27	6.55

SOURCE: EIA (2006b, Table 34).

Values of Energy Supply and Demand Elasticities

As noted in the main text, part of our sensitivity analysis included different values for key supply and demand elasticities in the model. Table A.18 summarizes the ranges of values for the elasticities whose values we varied. The elasticities of nonelectric natural gas demand in the United States, nontransportation-oil demand in the United States, and non-U.S. total oil demand were set at –0.5, –0.5, and –0.4, respectively.

Impacts on Energy Expenditures

If we let the subscript 1 denote variables with the renewable requirement and 0 denote corresponding variables without the requirement, then it follows that the change in total expenditure, price multiplied by quantity, satisfies

$$P_1Q_1 - P_0Q_0 = \left(P_1 - P_0\right)Q_0 - P_1\left(Q_0 - Q_1\right).$$

That is, the change in expenditure can be represented as the increase in the payment for the original quantity minus the reduction in quantity evaluated at the new price. This conceptual representation allows us to discuss the factors that we would expect to most substantially influence the changes in expenditures for fuels and electricity with the renewables requirements, given the expectation that, in many cases, at least, the costs of the alternative resources will be higher than the fossil resources they replace.

In the case of electricity, one obvious influence is how rapidly the incremental cost of substituting renewable for fossil-generated electricity rises as the total amount of renewables use expands. Given our simplifying assumption of average-cost electricity pricing, this curve will influence how much the price of electricity must rise to cover costs. Note, however, that, while the average price will depend on the amount used and the cost per unit of each type of renewable introduced, the averaging of these factors into the price reduces the influence of errors in the specification of any one cost factor. This would not be the case if we were estimating changes in economic surplus, where the incremental costs of each technology affect the size of the net consumer-plus-producer surplus. This is one of the reasons that changes in expenditure are not a reliable guide to impacts on overall economic efficiency (though impacts on total

Table A.18
Assumed Elasticity Values

	Elasticity Value		
Elasticity	**Low**	**Nominal**	**High**
Transportation-fuel demand	–0.2	–0.5	–0.8
Oil supply	0.2	0.4	0.6
Electricity demand	–0.2	–0.4	–0.6
Natural gas supply	0.2	0.4	0.6
Coal supply	0.7	1	1.3

surplus would need to be broken down into effects on consumers and producers to show the incidence of impacts).

Another important influence is the elasticity of electricity demand. The averaging of higher-cost renewables into the price of electricity has an effect on demand broadly similar to a tax on the final product. That, in turn, will reduce total demand, and, since the target is specified in terms of 25 percent of total demand, lower demand implies less need for the most expensive renewable alternatives. The more elastic the demand (that is, the more demand proportionately falls with a rise in price), the stronger this effect. The elasticities of supply for natural gas and coal also are relevant, since the displacement of demands for these fuels by the relative decline in fossil-based generation will lower their prices and thus the costs of remaining fossil generation (as well as the cost of natural gas direct end use). In our sensitivity analyses, however, we tend to find that the demand elasticity is a stronger influence (since fuel costs are only part of total generation costs).

Broadly similar reasoning applies to the expenditure impacts of renewable-fuel requirements, though here we must keep in mind the differences in possible mechanisms for pricing. The steepness of the overall supply curve for renewable fuels (taking into account all influences on feedstock and other costs, as discussed in Chapter Three), is one obvious influence. If transportation-fuel prices rise under the renewables requirement, either because of a revenue-neutral cross-subsidy from nonrenewable to renewable fuels or because of marginal cost pricing in which renewable costs set the price, then transportation-fuel demand will fall. The more elastic is this demand, the less will be the relative need to utilize more expensive renewables. This effect does not arise if the government directly subsidizes renewable fuels out of general revenues to maintain their price at parity with fossil alternatives; in this case, the lack of a conservation effect will raise government outlays relative to a scenario in which prices are allowed to rise. In the case of marginal cost pricing, in contrast, a larger increase in consumer expenditure can be anticipated, reflected in part in large transfers in revenues from consumers to fossil-energy producers that receive prices above their costs.

The other important factor in this case is the elasticity of petroleum supply available for transportation (taking into account supply elasticities in various geographical regions and nontransportation-oil demands). The renewables requirement for transportation, by reducing demand for petroleum, puts downward pressure on crude-oil prices and, thus, gasoline and diesel prices. The more inelastic this net supply, the more the demand drop will translate into lower gasoline and diesel prices and thus lower expenditures for fossil transportation fuels (though this would, in turn, stimulate demand).

Calculation of Net CO_2 Impacts

Electricity

In the electricity sector, the model calculates the mix of renewable resources used to meet the policy requirement. By construction, the model also calculates the nonrenewable resources for which the new electricity sources substitute. By calculating the net difference between CO_2 emissions from the renewable and nonrenewable sources, we can estimate the change in those from renewable electricity. Formally, the calculation is

$$\sum_{i} \sum_{j} \left(\mathrm{CO}_{2j}^{\ NR} - \mathrm{CO}_{2i}^{\ R}\right) \times \text{generation}_{i,j},$$

where $\mathrm{CO}_{2j}^{\ NR}$ is the life-cycle CO_2 emissions from nonrenewable technology *j* in units of tonnes of CO_2 equivalent per MWh, $\mathrm{CO}_{2i}^{\ R}$ is life-cycle CO_2 emissions from renewable technology *i* in units of tonnes of CO_2 equivalent per MWh, and $\text{generation}_{i,j}$ is the amount of electricity generation from renewable electricity source *i* that substitutes for electricity from nonrenewable source *j*.

We also account for reductions in CO_2 emissions that occur through conservation. In most scenarios, electricity prices increase and demand drops, thereby decreasing emissions of CO_2. The model tracks the change in generation from new, nonrenewable electricity sources, and, formally, the calculation is

$$\sum_{j} \mathrm{CO}_{2j}^{\ NR} \times \text{generation reduction}_{j},$$

where $\mathrm{CO}_{2j}^{\ NR}$ is the same emission factor described in the preceding equation, and $\text{generation reduction}_{j}$ is the amount of electricity generation from nonrenewable source *j* reduced through conservation.

We estimate life-cycle CO_2 emission factors by combining data from EIA and literature values. In each AEO, EIA projects the carbon content of fossil fuels and the efficiencies of electricity-generation technologies. We combine this information to estimate CO_2 emissions from burning fossil fuels to produce electricity. To estimate the full life-cycle emissions, we use estimates from the literature on the CO_2 emissions that occur in the remainder of the life cycle. In a recent literature survey, Meier et al. (2005) estimated emissions that occur in the fuel cycle (emissions from extraction and transportation of fossil fuels) and "fixed" emissions from power-plant construction, materials, and decommissioning. Tables A.19 through A.23 display the data used to estimate emission factors.

The Fuel Carbon Content column shows EIA's assumed values for the carbon content of natural gas and coal consumed in the electricity sector. These values are later converted to emission rates for specific power plants using the heat rates for fossil-fuel power plants. The Fuel-Extraction and -Delivery Emissions column shows the estimate of emissions that occur while extracting and transporting coal and natural gas to a power plant. Natural gas actually has a higher CO_2-equivalent emission rate due to the higher global-warming potential of

Table A.19
Fuel-Cycle Carbon-Emission Data

Fossil Fuel	Fuel Carbon Content (millions of tonnes per quad)	Fuel-Extraction and -Delivery Emissions (tonnes of CO_2 equivalent per GWh)	Fixed Emissions (tonnes of CO_2 equivalent per GWh)
Natural gas	52.8	80.9	3.4
Coal	94.3	48.0	1.2

SOURCES: Fuel carbon content: EIA (2006a). Fuel-extraction and -delivery and fixed emissions: Meier et al. (2005).

Table A.20
Heat Rates for New Power Plants

Generation Technology	Heat Rate (BTUs/kWh)
Pulverized coal	8,600
Advanced coal (IGCC)	7,200
Advanced combined-cycle gas	6,333
Conventional combined-cycle gas	6,800
Advanced combustion turbine	8,550
Conventional combustion turbine	10,450

Table A.21
Life-Cycle CO_2 Emission Rates for Fossil-Fuel Plants

	Emission Rate (tonnes of CO_2 equivalent per MWh)			
Generation Technology	Generation	Fuel Cycle	Fixed	Total
Pulverized coal	0.81	0.048	0.001	0.86
Advanced coal (IGCC)	0.68	0.048	0.001	0.73
Advanced combined-cycle gas	0.33	0.081	0.003	0.42
Conventional combined-cycle gas	0.36	0.081	0.003	0.44
Advanced combustion turbine	0.45	0.081	0.003	0.54
Conventional combustion turbine	0.55	0.081	0.003	0.64

Table A.22
Life-Cycle CO_2 Emissions for Renewable and Nuclear Generation

Generation Technology	Life-Cycle Emissions (tonnes of CO_2 equivalent per MWh)
Biomass	0.046
Geothermal	0.015
Co-firing	0.046
Wind	0.014
Solar thermal	0.039
Nuclear	0.017

methane relative to CO_2. The majority of the emissions in this portion of the life cycle come from leaking methane into the atmosphere (Meier et al., 2005). The Fixed Emissions column shows the emissions that occur during construction of the plant, building the materials, and decommissioning, under the assumption of a 30-year operating life.

Table A.20 shows EIA's assumptions about fossil-fuel power-plant heat rates. This information is used to estimate the life-cycle emissions from electricity generation in each plant, which are shown in Table A.21. We display the rate for the three portions of the life cycle and the total in similar units of tonnes of CO_2 equivalent per MWh.

Table A.23
Transportation-Fuel CO_2 Emission Rates

Biofuel	CO_2 Emissions (g of CO_2 equivalent per MJ)	Reference Emissions (g of CO_2 equivalent per MJ)	Change in CO_2 (g of CO_2 equivalent per MJ)	Change in CO_2 (millions of tonnes of CO_2 per quad of biofuel)
Cellulosic ethanol	11	94	–83	–87.6
FT gasoline	11	94	–83	–87.6
FT diesel	11	82.3	–71.3	–72.2
Biodiesel	49	82.3	–33.3	–35.1

SOURCES: Farrell et al. (2006), Hill et al. (2006).

Meier et al. (2005) also reported emission factors for the remaining technologies considered in this study. The emission rates in Tables A.21 and A.22 are used to calculate the difference between emissions from the renewable and nonrenewable sources. The model tracks how renewable electricity substitutes for nonrenewable generation, and we multiply the amount of generation substituted by the difference in emission rates.

Biofuels

The CO_2 calculation for biofuels follows the same format as that for the electricity market. We estimate the change in CO_2 emissions for each biofuel and the nonrenewable fuel substitute. We then multiply the amount of biofuels produced by the difference in emissions. We also estimate emissions saved from conservation by multiplying the reduction in gasoline and diesel by their life-cycle emissions.

Our estimates of life-cycle fuel emissions come from two recent studies. Farrell et al. (2006) estimated life-cycle emissions from corn-based and cellulosic ethanol. Hill et al. (2006) estimated life-cycle emissions from biodiesel. Due to limited information in the literature, we have assumed that fuels derived via the FT or MTG method will have similar life-cycle emissions to those from cellulosic ethanol. Our estimates do not reflect the findings of two new studies suggesting that biomass utilization can cause net CO_2 emissions to increase after accounting for land-use conversion that occurs directly or indirectly as new land is cleared to grow crops that were displaced for biofuels (Fargione et al., 2008; Searchinger et al., 2008). These studies show that the actual net CO_2 impacts of biofuels are highly sensitive to how they are produced. In light of these new studies, the values we calculate should be considered as upper bounds for emission reductions.

Table A.23 shows life-cycle emissions from each biofuel in units of grams (g) of CO_2 equivalent per megajoule (MJ) of energy. The reference fuel for cellulosic ethanol and FT gasoline is conventional gasoline, with life-cycle emissions reported at 94 g CO_2 equivalent per MJ (Farrell et al., 2006). The reference fuel for FT diesel and biodiesel is a conventional low-sulfur diesel, with life-cycle emissions reported at 82.3 g CO_2 equivalent per MJ (Hill et al., 2006). The final two columns report the changes in CO_2-equivalent emissions by substituting biofuels. The transportation-market portion of the model calculates the quads of each biofuel produced and quads of gasoline and diesel reduced through conservation. These quantities are multiplied by the values in the last column to estimate the change in CO_2 emissions.

Incremental Costs of CO_2 Reduction and Land Conversion

Two additional measures calculated in our analysis are the incremental costs of CO_2 reduction and land-use conversion. The incremental costs are the difference between renewable and nonrenewable costs at the 25 percent requirement level per unit of CO_2 reduction. It is important to note that this calculation is done for the renewable resource at the margin and represents the additional costs of reducing CO_2 by producing another gallon or kWh of renewable energy. Our model provides the estimate of the cost difference of the marginal resource. For the CO_2 reductions, we need to make an assumption to calculate the emission reductions. We assume, for electricity, that wind power is the marginal resource and use the CO_2 differences shown in Table A.23 for the calculation. In the motor vehicle–fuel market, we assume that either cellulosic ethanol or gasoline from either the FT or MTG process provides the marginal resource and that conventional low-sulfur gasoline is the reference nonrenewable resource.

For land conversion, we estimate the amount of biomass consumed from lands converted to energy-crop production. This is the amount of biomass demand beyond the low-cost supplies. We assume an average yield of 5 tons of biomass per acre of land (Graham and Walsh, 1999). The future productivity of lands devoted to energy-crop production is another large uncertainty. If average yields are higher, then the amount of land-use conversion declines. The converse is true if average yields are lower.

Exploratory-Modeling Analysis

Exploratory modeling is used to identify the key factors affecting the expenditure and CO_2 impacts of the renewables requirements. Table A.24 summarizes the uncertain input parameters in our simulation model and the range of values we have assumed for each.

Where applicable, Table A.24 provides the initial values drawn from documentation of EIA's 2006 AEO reference case, which become a starting point for the uncertainty analysis. We use the ranges between the low and high values to generate a sample of possible future scenarios and run the model using these parameter values to calculate the impacts on expenditures and CO_2 reductions. For most electricity-technology costs, we use EIA's 2006 AEO estimate as a starting point and DOE program goals as a lower bound for potential cost reductions. For technologies that are still under development today, we include potential for higher costs to allow for greater cost escalation.

The first set of variables applies to the electricity market:

- *Wind capital-cost change* varies the capital cost of wind that adjusts the y-intercept of the cost curve for wind.
- *Wind cost-escalation factor* varies the size of the cost steps for the wind supply curve.
- *Biomass cost change* varies the nonfeedstock costs for dedicated biomass power plants.
- *Geothermal escalation factor* varies the cost steps in the geothermal supply curve. The initial cost step remains fixed, and the additional steps either decrease or increase relative to the initial level.

Table A.24
Uncertain Parameters Used in Experimental Design

	Value		
Electricity	**Low**	**High**	**Initial**
Wind capital-cost change (% change)	–40	0	$0.058 per kWh
Wind cost-escalation factor (% change)	–50	50	0, 20, 50, 100, 200
Biomass cost change (%)	–20	20	$0.041 per kWh (excludes feedstock)
Geothermal escalation factor (% change)	–25	25	$0.05, $0.075, $0.10, $0.15, $0.20, $0.25, $0.35 per kWh
Natural gas supply elasticity	0.2	0.6	—
Coal supply elasticity	0.7	1.3	—
Electricity demand elasticity	–0.2	–0.6	—
Wind capacity credit	0	0.4	—
Solar-thermal cost (% change)	–30	30	$0.135 per kWh
Solar-thermal quantity (% change)	–30	30	—
Fuels			
Biofuel production cost ($ per unit of input)	67	134	—
Low-cost biomass supply (millions of tons)	450	1,000	—
Feedstock supply distribution	EIA	UT	—
Biomass-backstop price ($ per ton)	90	200	—
Biofuel yield (gallons per ton)	80	100	—
Oil supply elasticity	0.2	0.6	—
Transportation demand elasticity	–0.2	–0.8	—
Shift in oil supply curve (% change)	–10	10	$48 per barrel
Electricity co-product (kWh per gallon)	0	2	—

- *Natural gas and coal supply elasticities* vary the supply elasticities in the supply models used for these resources.
- *Electricity demand elasticity* varies the price elasticity of demand used in the electricity demand function.
- *Wind capacity credit* varies the credit that wind power receives in displacing capital costs of firm power resources.
- *Solar-thermal cost* varies the LCOE for solar-thermal power.
- *Solar-thermal quantity* varies the available capacity for solar-thermal power.

The next set of factors affects the motor-vehicle transportation–fuel market:

- *Biofuel production cost* varies nonfeedstock conversion costs for biofuels.

- *Low-cost biomass supply* varies total biomass feedstock supply from waste and marginal lands available at a cost of less than $90 per ton.
- *Feedstock supply distribution* varies the relative distribution of biomass in the different cost steps of the supply curve. The variable ranges from 0, which represents EIA's cost curve with more biomass in the high-cost portions, to 1, which represents the distribution of UT's supply curve with more biomass in the lower-cost steps.
- *Biomass backstop price* varies the cost of supplying biomass from converted agricultural lands and pasturelands.
- *Biofuel yield* varies the yield of biofuel gallons per ton of feedstock.
- *Oil supply elasticity* varies elasticity of supply in the world oil-market model.
- *Transportation demand elasticity* varies the price elasticity of demand used in the function for transportation demand.
- *Shift in oil supply curve* varies the projected world oil price.
- *Electricity co-product* varies the amount of electricity exported to the grid per gallon of biofuels produced.