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TECHNICAL REPORT

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

Michael Toman, James Griffin, Robert J. Lempert

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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Preface

At the request of the Energy Future Coalition, the RAND Corporation undertook a study that assesses the potential impacts on U.S. consumer energy expenditures and carbon dioxide (CO_2) emissions of producing 25 percent of U.S. electric power and transportation fuels from renewable resources by 2025. The coalition spearheads the 25x'25 Alliance, a group of individuals and organizations with a vision that, "by the year 2025, America's farms, ranches and forests will provide 25 percent of the total energy consumed in the United States, while continuing to produce safe, abundant and affordable food, feed and fiber" (25x'25 Alliance, 2007, p. 2).

In November 2006, RAND issued an initial publication of its methods and findings. After RAND identified a number of flaws in both approach and results subsequent to the publication, RAND withdrew the report and set about to produce a completely revised publication. This revised version of the report has been subjected to very detailed peer review of both methods and findings in an effort to ensure its analytical soundness.

This report presents a general description of the approach that RAND researchers undertook in conducting the revamped study and the key findings that emerged from it. A more detailed look at the study methods and results can be found in companion technical appendixes that are available electronically. The analysis in the report can help inform policymakers, lawmakers, and others on how different assumptions about the future affect the possible economic and environmental consequences of a significant increase in renewable-energy use.

This research is part of a growing portfolio of RAND research on alternative energy sources. Other examples include

- *Oil Shale Development in the United States: Prospects and Policy Issues* (Bartis et al., 2005)
- *Producing Liquid Fuels from Coal: Prospects and Policy Issues* (Bartis, Camm, and Ortiz, forthcoming)
- *Federal Incentives to Induce Early Experience Producing Unconventional Liquid Fuel* (Camm, Bartis, and Bushman, forthcoming).

The RAND Environment, Energy, and Economic Development Program

This research was conducted under the auspices of the Environment, Energy, and Economic Development Program (EEED) within RAND Infrastructure, Safety, and Environment (ISE). The mission of RAND Infrastructure, Safety, and Environment is to improve the development, operation, use, and protection of society's essential physical assets and natural resources and to enhance the related social assets of safety and security of individuals in transit and in their workplaces and communities. The EEED research portfolio addresses environmental quality and regulation, energy resources and systems, water resources and systems, climate, natural hazards and disasters, and economic development—both domestically and internationally. EEED research is conducted for government, foundations, and the private sector.

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Introduction

Sharply higher prices for oil over the past several years, concerns about energy security, and growing worries about global warming have greatly increased interest in expanding renewable energy in the United States. Substituting renewable energy for fossil fuels would reduce emissions of carbon dioxide (CO_2), the most prevalent "greenhouse gas" (GHG) associated with global warming. By lowering demand for oil, substitution of renewable fuels could contribute to national energy security. In addition, increased renewable-energy supplies from rural areas could enhance rural incomes in the United States.

The penetration of renewable energy into the marketplace has been small, providing 9.5 percent of total U.S. electricity use (mostly hydroelectric power) and only around 1.6 percent in motor fuels in 2006. The market penetration of renewables has been held back principally by their higher cost relative to fossil energy. But cost relationships could change in the future.

In this report, RAND researchers assess the potential impact on U.S. consumer energy expenditures of producing 25 percent of U.S. electric power and motor vehicle–transportation fuels from renewable resources by the year 2025 and to examine the potential effects of this mix of energy use on national CO_2 emissions. The baseline for the comparisons was expenditures and CO_2 emissions in 2025 as drawn from the reference-case tables of the Energy Information Administration's (EIA's) 2006 *Annual Energy Outlook* (AEO) (EIA, 2006a, 2006b). However, the researchers also consider the implications of future energy prices much higher than these reference-case values.

The researchers focused on the impacts of expanded renewables use in the motor-fuel and electricity sectors, while taking into account the impacts that such changes in energy use would have in other domestic and international energy markets. The analysis did not address broader measures of economic impacts from the introduction of more-costly energy sources or the economic impacts of potential competition between food and fuel in the production of biomass-based energy production. Assessing impacts on consumer expenditures and CO_2 emissions requires many assumptions about future energy costs and demands, factors that remain highly uncertain. These factors include not just the rate of advance in renewable-energy technologies but also the costs of fossil energy (in particular, the future price of oil) and the availability of renewable resources (in particular, biomass).

To facilitate addressing these uncertainties, basic supply-and-demand–type models were used to describe possible snapshots of 2025 energy markets in terms of prices, quantities used, expenditures, and CO_2 emissions. In the analysis of model results, the goal was *not* to identify any single "most likely" scenario for future energy costs or patterns of energy use. Instead, we considered a large number of scenarios based on ranges of values for key parameters to illustrate the range of possible impacts on energy expenditures and CO_2 emissions that might result from the renewable-energy requirements.

Key Findings

Based on our analysis of the 25 percent renewable-energy requirements, we found the following:

- Substantial variation exists in potential expenditure changes across scenarios, especially in the motor-vehicle transportation–fuel market. Depending on the assumptions made, expenditure changes can be minimal or show a very substantial increase.
- The government's approaches to implementation of the policy requirements—particularly with respect to motor-fuel pricing—have important effects on consumer behavior and expenditures. In particular, passing the cost of more expensive renewable fuels to final pump prices will increase the direct impacts on expenditure, but it will also serve to generate improvements in energy efficiency. Subsidizing more expensive fuels will mitigate the direct impacts on expenditure, but only by transferring the expenditure to the government budget.
- Meeting the 25 percent requirements with relatively low expenditure impacts requires significant progress in renewable technologies. Biomass availability, in particular, is one of the factors that can have the greatest implications for consumer expenditure changes. Another important factor is the degree of technical advance in wind power. The U.S. Department of Energy (DOE) has set ambitious program goals for renewable technologies that, if achieved, would significantly moderate the expenditure impact of the 25 percent requirements. But if progress falls short of these goals, the requirements could be expensive. This is a real possibility, given the ambitiousness of these particular goals and the general tendency for technology-development programs to have optimistic early stage cost estimates.
- Lower levels of the requirements (15 or 20 percent) decrease expenditure changes more than proportionately, although they also result in lower CO_2 emission reductions than the 25 percent requirements.
- The 25 percent requirements can reduce CO_2 emissions significantly, but the additional cost of energy supply per unit of reduced CO_2 emissions can vary considerably. Unless there is very substantial cost-reducing technical innovation for expanding renewables, the incremental cost would be higher than the levels of incremental costs often encountered in current policy discussions.

Implications

While the objective of significantly increasing renewable-energy use in motor fuels and electricity seems technically achievable, our findings indicate that the resulting impact on consumer energy expenditures is quite uncertain. The wide range of potential expenditure impacts reflects several significant uncertainties with respect to the future availability and cost of renewable-energy sources. Of all the uncertainties, none looms larger than those affecting the cost of bringing significant new volumes of biofuels to market.

Given this finding, *a large, inexpensive, and easily converted biomass supply is necessary for significantly increased renewable-energy use to have relatively low impact on consumer energy expenditures. The significant resulting increase in biomass usage would require harvesting various energy crops at a scale that vastly exceeds current practice.* Greatly increased biomass production could be accompanied by adverse environmental and economic impacts due to land conversion. There is also the possibility that land-use changes engendered by higher reliance on biomass could result in a temporary increase in GHG emissions. *Technical advances in the provision of economically and environmentally sound feedstock should be a top priority for R&D programs focused on increasing biomass-based energy supplies.*

The renewable-fuel requirements reduce global demand for petroleum and lower the international price of crude oil. This oil price impact from fuel diversification can be seen as enhancing energy security. Energy security also depends on how exposed the economy is to oil price shocks. Substitution of relatively costly renewable fuels for fossil-based alternatives at a 25 percent level may do relatively little to mitigate that risk, since, in competitive wholesale and retail fuel markets, the prices of the alternatives will be highly correlated with the price of oil.

Our analysis also indicated that increasing the share of renewables to 25 percent can significantly reduce CO_2 emissions. However, the incremental increase in energy cost per unit of CO_2 reduction varies widely depending on circumstances, reaching high levels unless there is very substantial cost-reducing innovation in expanding renewables. Fossil-fuel prices that are higher than the baseline levels assumed in this analysis would induce greater use of renewable energy and thus reduce the incremental cost of achieving 25 percent renewable energy (thereby also lessening the need for setting this as a policy target). High fossil-fuel prices also improve the economics of other alternatives that can reduce GHG emissions and improve energy security, such as energy efficiency and unconventional energy sources.

Given these findings, *increased renewables use can reduce CO_2 emissions and could enhance energy security by reducing petroleum use; however, these gains likely could be realized more cost-effectively through a diverse portfolio of energy measures that improve energy efficiency, reduce CO_2 emissions, and increase the availability of energy sources other than conventional petroleum. Moreover, while the pricing of renewable fuels can be used to insulate consumers from price changes, this approach adversely affects energy efficiency and the development of other alternatives and increases pressure on the federal budget from subsidizing higher-cost fuels.*

Requirements for renewable-energy use could be a part of the portfolio, and they already are being developed by a number of states for use in the electricity sector. They could be justified conceptually as a way to reduce initial investment barriers by stimulating greater private-sector R&D and learning through doing and as an alternative to price-based policy instruments if those are handicapped by political constraints. Our findings suggest that renewables requirements on the order of 25 percent could be met with modest impacts on consumer energy expenditures if there is substantial progress in several key renewable-energy technologies and biomass feedstock production. However, if significant technological advances do not occur in these areas, then the policy could become quite costly. Moreover, our analysis provides only a snapshot of annual expenditures in 2025 and does not deal with the higher outlays in intermediate years of the transition, when substantial new capital would have to be invested and technologies are still relatively underdeveloped. These observations suggest that any requirements for increased use of renewables not only should be part of a larger policy portfolio, but also should be phased in gradually and carefully reviewed periodically to assess how technology is advancing before requirements are raised further.

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Abbreviations

AEO	*Annual Energy Outlook*
BTU	British thermal unit
CCS	carbon capture and sequestration
CO_2	carbon dioxide
DOE	U.S. Department of Energy
EEED	Environment, Energy, and Economic Development Program
EERE	Office of Energy Efficiency and Renewable Energy
EGS	enhanced geothermal systems
EIA	Energy Information Administration
FT	Fischer-Tropsch
g	gram
GDP	gross domestic product
GHG	greenhouse gas
GIS	geographic information system
GW	gigawatts
GWh	gigawatt-hour
IGCC	integrated gasification combined cycle
kW	kilowatt
kWh	kilowatt-hour
lb	pound
LCOE	levelized cost of electricity
LHS	Latin hypercube sampling
MIT	Massachusetts Institute of Technology

MJ	megajoule
MMBTU	thousand thousand British thermal units
MTG	methanol-to-gasoline
MW	megawatt
MWh	megawatt-hour
NBB	National Biodiesel Board
NEMS	National Energy Modeling System
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OPEC	Organization of the Petroleum Exporting Countries
PRIM	Patient Rule Induction Method
PV	photovoltaic
RFF	Resources for the Future
USDA	U.S. Department of Agriculture
UT	University of Tennessee
WGA	Western Governors' Association
WinDS	Wind Deployment System Model

CHAPTER ONE

Introduction

Background

Sharply higher prices for oil over the past several years, concerns about energy security, and growing worries about global warming have greatly increased interest in expanded renewable energy in the United States. Renewable-energy sources are those that are inherently nondepletable or that can be naturally replenished in a relatively short period of time, such as wood, waste, wind, hydroelectric, photovoltaic (PV), and solar-thermal energy. Geothermal energy is also usually lumped together with these resources.

One of the most visible signs of the increased interest in renewables was the proposal by President George W. Bush in his 2007 State of the Union address to reduce U.S. petroleum consumption in motor fuels by 20 percent in the next 10 years, with particular emphasis on renewable fuels. In addition, many states have set or are setting requirements for using renewable energy in the electrical-power sector (see EERE, 2008).

Substituting renewable energy for fossil fuels would reduce emissions of carbon dioxide (CO_2), the most prevalent "greenhouse gas" (GHG) associated with global warming.[1] By their very nature, wind and solar energy do not generate CO_2 emissions. The CO_2 generated by burning biomass energy derived from plant sources can be mitigated by the reabsorption of CO_2 in the growth of new biomass feedstocks, although the net savings will depend on how the biomass is grown and on resulting land-use changes. Increasing renewable-energy use can also lower demand for oil. Many advocates of increasing the use of renewables point to this as contributing to national energy security. Finally, there is the potential for increased renewable-energy supply from rural areas to enhance rural incomes in the United States.

The penetration of renewable energy into the marketplace has been small. In 2006, renewable energy supplied about 9.5 percent of total U.S. electricity use, most of that through large-dam hydroelectric facilities. The usage of renewable energy in motor fuels—primarily alcohol derived from corn and blended into gasoline to meet certain clean-air requirements—is an even smaller fraction of total energy use in that sector, amounting to only around 1.6 percent (EIA, 2006a).

One major factor limiting the market penetration of renewables has been their higher cost relative to fossil energy. Costs for renewables in the power sector, especially wind, have declined considerably over the past 20 years. However, even with tax credits and other forms of subsidization, the costs of renewables have not yet declined far enough to make significant inroads in

[1] For a comprehensive review of global warming, see IPCC (2007).

the market, especially when fossil-energy plants also have become more efficient and coal prices have remained relatively low over the same time frame (McVeigh et al., 1999).

However, this set of cost relationships could change in the future. As already noted, fossil-energy prices have been higher in the past few years than they were previously. Moreover, research in the public and private sectors continues to bring down the costs of renewables. Thus, even if the costs of using fossil energy did not increase in the future because of policies for reducing CO_2 emissions, renewables could come to occupy a larger share of the market for power and motor fuels.

Objectives

The RAND Corporation was asked to assess the potential impact on U.S. consumer energy expenditures and national CO_2 emissions of producing 25 percent of U.S. electric power and motor vehicle–transportation fuels from renewable resources by the year 2025. Our analysis includes impacts on consumer expenditures, which will, in turn, reflect payments of any fossil-fuel taxes specifically imposed for promoting the introduction of renewable alternative fuels. We also include any additional government expenditures for tax breaks or direct fuel subsidies used for that purpose and any revenues from fossil-fuel taxes that are imposed to improve the price-competitiveness of alternative fuels. We maintain government revenue neutrality in all the expenditure comparisons—that is, no net change in the deficit or surplus.

Economic analyses of policy impacts usually examine the overall cost and benefit to society of different alternatives. For this study, such analysis would assess potential changes in total economic surplus from using more-costly energy resources and technologies. Results on consumer expenditures do not provide the same information, since, for example, those expenditures may be held down through government-financed subsidies or they may be raised by policies that allow suppliers to earn abnormally high profits. We touch on these points further when we present our results in Chapter Three.

Approach

To carry out the objective, RAND researchers focused on the impacts of expanded renewables use in the motor-fuel and electricity sectors, while taking into account the impacts that such changes in energy use would have in other domestic and international energy markets. Assessing these impacts on consumer expenditures and CO_2 emissions requires many assumptions about future energy costs and demands, factors that remain highly uncertain. These include not just the rate of advance in renewable-energy technologies but also the costs of fossil energy (in particular, the future price of oil) and the availability of renewable resources (in particular, biomass).

The baseline for the comparisons was energy expenditures, projected energy supply investments, and CO_2 emissions in 2025 drawn from the reference-case tables of the Energy Information Administration's (EIA's) 2006 *Annual Energy Outlook* (AEO) (EIA, 2006b).[2] A 25 per-

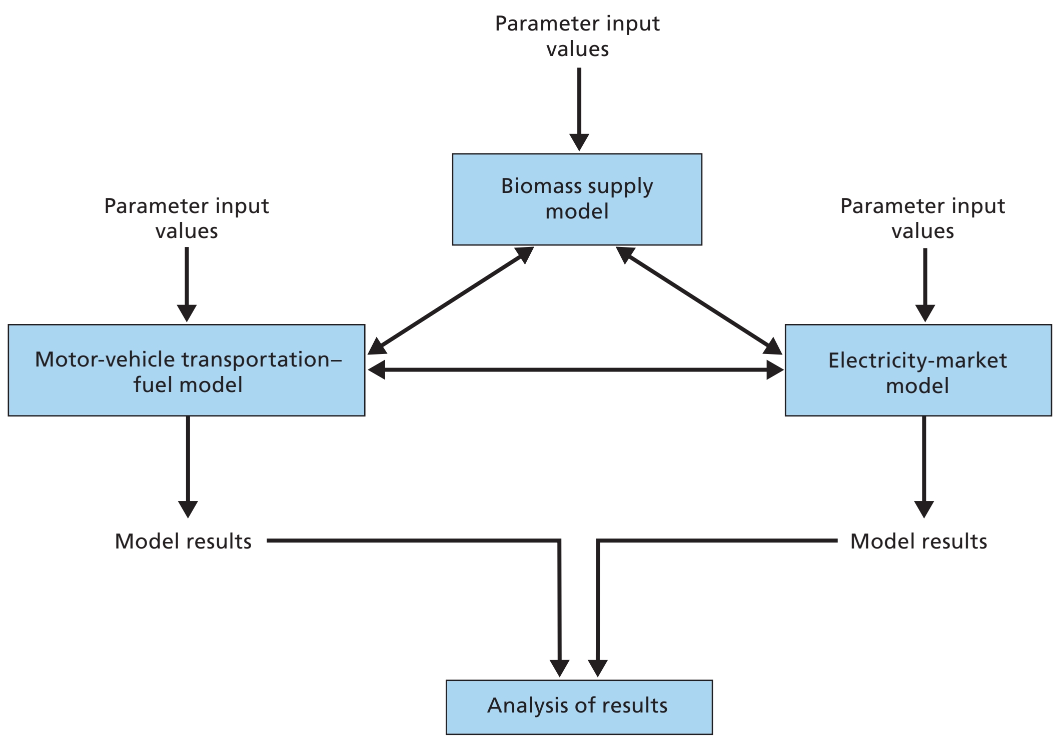
[2] The analysis underlying the study was completed prior to the publication of AEO 2007. Reference-case oil prices for 2025 in more recent AEOs have been higher than 2006 figures, though still well below the high prices experienced in

cent requirement by 2025 implies a more-than–15 percent increase in renewable-energy usage in electricity and more than 21 percent for motor fuels, compared to that baseline.

An overview of RAND's approach is shown in Figure 1.1. (More detail on the approach can be found in Chapter Two and in Appendix A.) Basic supply-and-demand–type models are used to describe possible snapshots of 2025 energy markets in terms of prices, quantities used, and expenditures. This static approach necessarily does not deal at all with transition issues (in technology and investment), except very indirectly in the different assumptions one makes about available technological options in 2025.

By varying input parameters, the market models for electricity and motor fuels are run numerous times to look at technological and economic uncertainties. There is also a separate model that relates biomass feedstock supply under different assumptions with demands for feedstocks from both market models. The electricity- and motor fuel–market models include simplified representations of the potential availability of alternative renewable-energy technologies at different incremental costs. The market models use basic representations of energy demand for different possible market prices and systems of supply and demand for primary energy (oil, gas, and coal). We can then account for feedback effects of renewables requirements on primary energy prices. The electricity model is more complicated, because electricity is produced using a variety of technologies and primary energy types, and these, in turn, are used in different ways on a daily, seasonal, and annual basis (e.g., "base-load" coal plants

Figure 1.1
High-Level Overview of Approach



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2007–2008. In Chapter Three, we discuss the implications of high future oil prices for the analysis.

versus natural gas–fueled turbines to meet highly episodic peak demand). In both sectors, however, the basic logic of the model can be sketched out using simple supply-and-demand–type reasoning.

Starting from the top of Figure 1.1, we have inputs to each model. These are the assumptions about technology costs, capacities, and so forth. We established ranges for these values and developed a sample of 3,000 different combinations of all the inputs using a statistical-sampling method. These values are fed into the separate models. The models take the input information and calculate the impacts on energy expenditures and CO_2 emissions. After running all the cases, and excluding those that do not converge after many iterations, we have a database of almost 2,600 input combinations and their results.[3]

In the analysis of results, the goal was *not* to identify any single "most likely" scenario for future energy expenditures or patterns of energy use. Instead, we analyzed the collection of scenarios to identify the key factors influencing the expenditure impacts of the renewables requirements. This analysis highlights those factors that seem to have the greatest influence on relatively high or low expenditure impacts. This, in turn, highlights the uncertainties whose reduction would be particularly useful in charting future policy for renewable-energy development and utilization. These include a variety of technology uncertainties in the evolution of different renewable sources, as well as uncertainties about the range of energy-market responses to the supposed change in patterns of energy use.

Organization of This Report

The remainder of this report includes an overview of how we did the analysis (Chapter Two), an overview of key findings from the effort (Chapter Three), and some overall conclusions and implications (Chapter Four).

Appendixes A and B, in electronic form, contain much more detailed discussions of the approach and findings.

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[3] As can be seen in the next chapter, the various supply curves in the models are relatively flat, with discrete "stair-step" representations of different technologies. It is sometimes difficult under these conditions to get iterative models to converge. There was no indication in the results that the scenarios in which convergence was not obtained had disproportionately represented particular kinds of assumptions, such as high or low incremental costs of renewables.

CHAPTER TWO

How We Did the Analysis

Introduction

This chapter describes the basic components of the two market models we constructed to analyze the impacts of renewable-energy requirements (shown in Figure 1.1 in Chapter One) and our approach to addressing uncertainties surrounding key model parameters through sensitivity analyses. A more detailed description of our approach can be found in Appendix A, including the ranges of numerical parameter values we used in the analysis. As noted in Chapter One, the impacts generated by the models are calculated relative to numbers based on the 2025 reference-case projections in EIA (2006b), with discussion later about the implications of higher prices.

Overview of the Electricity and Fuel Market Models

We use simplified representations of supply and demand for electricity and motor fuels and similar models for primary fossil-energy sources (oil, natural gas, and coal) in order to account for feedback effects of renewables requirements on the prices of fossil energy. We run the electricity and fuel models separately, but (as shown in Figure 1.1 in Chapter One) we account for interactions between them in the competition over biomass feedstock that can be used to produce motor fuels or electricity.

The electricity and fuel models use the same five basic steps to calculate energy demand and prices, which are then used to determine energy expenditures:

- Construct a set of cost curves for renewable-energy technologies based on assumptions about technology costs and corresponding production capacities.
- Calculate additional supply costs for meeting renewable-energy requirement.
- Determine substitution effects of renewable-energy use on fossil-fuel markets.
- Calculate new market prices for energy consumers.
- Calculate new energy demand based on new prices.

The two models each iterate through this sequence until the deviation in demand between model runs is less than 1 percent. As noted, the two models are integrated at several steps to reflect competition over biomass supply.

Step 1: Construct Cost Curves for Renewable-Energy Technologies

At the core of this analysis, the model uses a set of cost curves that relate how the marginal costs[1] of a renewable energy source increase as the supply of that resource increases. The marginal costs of supply increase at higher levels of supply because the most accessible, least-cost resources are developed first, followed by more expensive resources. For example, as increasing numbers of new wind turbines are built, the marginal costs for power from successive wind turbines increase. Similarly, as the supply of biomass-based energy rises, energy producers must rely on successively more costly additional feedstock supplies.

In our analysis, we use information from various existing technical reports on each renewable-energy technology to characterize these cost relationships. The shape of these curves is one of the significant uncertainties in this study. For most renewable technologies, the current amount of supply is small relative to the assumed policy targets. We can use current estimates of technology costs to understand the initial portions of the supply curve, but we have very limited information on how costs escalate as supply further increases. We also lack information on how costs for new output could fall through economies of scale and learning by doing.

Because of the significant uncertainties about the shape of these curves, we treat them as parameters to vary in the uncertainty analysis. The parameters reflect different assumptions made about the relative costs and potential capacities of each technology.

Step 2: Calculate Expenditure Impacts of Meeting Requirement

In this step, we develop an aggregate incremental cost curve based on the individual curves for each technology. In looking at the example of biofuels, we are interested in the increasing marginal costs for producing and delivering biofuels as the aggregate supply grows. We create an aggregate curve by combining cost curves from each technology and plotting constituent components of the curves from least to most expensive.

Once the aggregate incremental cost curve is built, we can determine the impacts of providing renewable energy to meet the assumed requirement. We start with an initial estimate of the demand for energy. For example, the 2006 AEO estimates the demand for motor vehicle–transportation fuels in 2025 at 13.5 million barrels per day motor fuel in gasoline-equivalent units (206.4 billion gallons), so a 25 percent renewable-energy requirement is 3.4 million barrels per day (51.6 billion gallons) of renewable fuels in gasoline-equivalent units. In our analysis, we find the point on the aggregate incremental cost curve at which the demand for renewable fuels intersects the curve, which tells us the marginal cost of producing that level of renewable fuels.

Step 3: Substitute Renewable Fuels for Fossil Fuel

With the information from the prior step on the amount of renewable fuel produced, we calculate the quantity of conventional fuel replaced and the change in the consumer cost of the conventional fuel. The substitution of biofuels for gasoline and diesel fuels lowers U.S. demand for crude oil. In our model, we use basic representations of supply and demand to determine how much the demand for oil drops and how the market price of crude oil changes in response. From this, we can calculate how much the expenditure on conventional fuel will decline with

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[1] *Marginal costs* are the costs of producing the next unit of a good.

the renewable substitution. For the electricity sector, we do equivalent calculations for coal and natural gas demand and prices.

Step 4: Calculate New Prices for Energy Consumers

In step 2, the model determines the cost of producing the required level of renewable energy. This information is then combined with information from step 3 on the cost of producing energy from fossil fuels into a single market price. How these costs are combined depends on assumptions about the policies applied to the prices of renewable and conventional energy. For instance, more-costly renewable motor fuels could be subsidized by a sufficient amount to equalize their price with those of conventional fuels and generate the level of production needed to meet the set requirement. Alternatively, fossil-based fuels could be taxed to equalize the prices. Finally, a policy could be put in place that combines taxes and subsidies to meet the renewable-energy requirement. For electricity, similarly, the impacts for consumer prices depend on how the costs of renewables and less expensive fossil-based electricity are incorporated.

Step 5: Calculate Energy Demand Based on New Prices

Step 5 uses the price information determined in step 4 to calculate new demands for motor fuels and electricity. We use basic demand equations in both the electricity and motor-fuel markets that are calibrated to EIA's energy projections. We plug in the new market prices from step 4 and calculate new demands. If there is a large difference between the demand calculated at this stage and the demand used at step 2, then the model iterates again. In the next iteration, the demand calculated in this stage becomes the initial value used in step 2.

There are important differences in the electricity and motor-fuel markets that are reflected in how these five steps are applied in the electricity and fuel models. Those specific components are now described in more detail.

Motor Transportation–Fuel Model

Most of the current policy-related discussion about renewable alternatives to gasoline and diesel fuel has focused on the potential for ethanol to substitute for gasoline. While ethanol in the United States is now derived almost entirely from corn, that process faces a number of constraints. It is an expensive process, taking into account both the direct added cost of ethanol manufacturing and the fact that, if the process is used on a large scale, it would be vastly more expensive, considering the opportunity cost of diverting corn from food to fuel use. Currently, corn ethanol is supplied mainly to meet blending requirements for cleaner-burning reformulated gasoline. Even at the current limited volumes produced, corn-based ethanol production benefits from an ongoing tax benefit.[2] Moreover, because corn is an energy-intensive crop, the net savings in CO_2 emissions from its use relative to gasoline are at best modest, with some

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[2] Gasoline blenders currently receive a $0.51 tax credit for each gallon of ethanol blended into the fuel supply. The credit is scheduled to expire in 2010.

recent estimates indicating that corn-based ethanol can *increase* emissions in some cases (Farrell et al., 2006; Searchinger et al., 2008; Creyts et al., 2007).[3]

In light of these constraints, to significantly expand renewable-fuel production in the United States for motor-fuel use, we need to focus on alternatives to corn-based ethanol. Accordingly, we treat the amount of corn-based ethanol in our analysis as fixed at the level projected in the 2006 AEO.[4] We assume that the aforementioned tax benefit for corn-based ethanol continues. We also allow for a limited amount of biodiesel fuel. Biodiesel is a diesel-like fuel produced from vegetable oils and animal fats that is typically blended with conventional diesel fuel. In our analysis, we have followed EIA's assumptions in the 2006 AEO for biodiesel availability. Our assumptions about pricing and tax treatment of non–corn-based renewables are more complicated, as discussed later in this chapter and in Appendix A.

The focus for expanding renewable fuels has been on "cellulosic" alcohol derived from more "woody" sources, such as agricultural-plant crop residues, wood-processing waste, and dedicated feedstock crops, such as switchgrass. These feedstocks are much less energy-intensive to produce and, thus, have a more favorable net CO_2 impact than does corn ethanol. They also are less likely to lead to environmental problems associated with cultivation (e.g., water pollution). However, production of ethanol from cellulosic fibers is chemically more difficult and complex than production from a starchy material, such as corn. Cellulosic-ethanol production technology is very much a technology still under development. Land availability also limits supplies of woody feedstocks.

While cellulosic-ethanol technology may turn out to be relatively attractive for replacing gasoline, other technologies also have significant potential. One example is the production of liquid fuel by converting biomass into a gas and then converting that gas into either gasoline or middle distillates,[5] using, respectively, the methanol-to-gasoline or Fischer-Tropsch (FT) approaches. The technology for each of these two approaches already exists and has been used commercially to produce liquid fuels from natural gas. The FT approach has also seen commercial application to produce middle distillates from coal. The key technological challenge in this case is the use of biomass as a feedstock.[6] In our analysis, we allow for the possibility of obtaining additional biofuels via cellulosic ethanol or biomass gasification followed by fuel synthesis. We make no effort to distinguish between these two alternatives in the representation of additional biofuel supply. Because there is no commercial experience in any approach for producing fuels from non–food-crop biomass, fulfilling a 25 percent renewable-energy requirement will require the development, testing, and scaling up of advanced technologies.

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3 The net CO_2 balance from the energy used in corn production and the storage in new crops may be a modest decline. However, if one accounts for the fact that new cultivation on land previously unused for that purpose can increase the release of carbon from decomposition of existing underground root systems and other underground "reservoirs," the net effect can be an increase in CO_2 for several decades. This observation potentially applies not just to corn but to any increased biomass cultivation. Since we do not include this effect in our CO_2 balance calculations for bioenergy production from unconventional feedstocks, our results for reduced CO_2 from greater biomass use are biased upward.

4 Our analysis considers only the potential for renewable fuel supplies in the United States; we do not consider the option of importing fuels from other countries that might also be expanding their production capabilities.

5 The "middle distillate" products of the FT method are automotive diesel fuel and jet fuel. About a third of the product is naphtha, which can be used as a chemical feedstock or upgraded to automotive gasoline.

6 Another option for renewable substitution is a "plug-in hybrid" vehicle that can use renewable electricity to recharge, rather than having to rely on an on-board combustion engine. However, because the availability and capital cost for this option remain very uncertain, we did not address that option in the study.

In addition, meeting the requirement will require a massive increase in the amount of biomass that is cultivated specifically for energy applications. It will also require considerable changes in the agriculture sector to produce feedstocks for both biofuel production and electricity generation. While these changes appear feasible, there is great uncertainty about the future cost of these biofuel technologies and how their costs change with capacity increases.

We have limited information available to construct cost curves for noncrop biofuel technologies. We use technical reports from the literature to bound plausible ranges for production costs. In our analysis, we allow for a range of possible production costs and run the model through thousands of simulations to understand the range of potential costs under a renewable-energy requirement.

We have defined the ranges for biofuel production costs and capacity to account for key factors affecting future technology costs. One factor is that production costs for a particular technology tend to decline over time as experience with the process grows. This trend is known as "learning by doing." A factor that runs counter to learning by doing is a common tendency to underestimate the cost of new technologies prior to commercial production. Prior to building actual commercial-scale plants, most estimates of technology costs are based on low-definition engineering designs. This reflects the state of knowledge for cellulosic ethanol and motor fuels produced by liquefaction of biomass. Earlier RAND research has shown that initial low-definition engineering designs underestimated the eventual cost of building first-of-a-kind commercial plants (Merrow, Phillips, and Myers, 1981). Therefore, while empirical evidence shows that scaling up a biofuel technology through a government-imposed requirement can reduce production costs over time, the initial baseline level of production costs often is underpredicted.

For these reasons, developing a set of cost curves for biofuel technologies is exceptionally difficult. Instead of trying to make a most likely estimate, we have assumed a broad range of possible costs and potential capacities. We deal with the expenditure impacts of biofuel requirements through simplified parametric representations of supply curves for biomass feedstock, capital and operating costs for converting biomass feedstock into biofuels, and conversion yields of biofuels per unit of biomass input.

Following the general steps outlined in the opening chapter, we integrate the cost curves for individual biofuel technologies into an aggregate biofuel supply curve. This provides an estimate of the marginal cost of producing biofuels. We then add a markup to reflect the costs of distribution, retail marketing, and taxes, which are based on projections from the U.S. Department of Energy (DOE). Following this step, we intersect the demand for biofuels with the aggregate curve.

Figure 2.1 shows an example of a plant-gate biofuel supply curve (excluding the markups just mentioned) under one set of parameter assumptions that falls in the middle of our assumed ranges for the parameters that describe biofuel supply.[7] The figure shows the amount of biofuel at successively increasing marginal costs of supply. A limited amount of biodiesel produced from "yellow grease" or waste oil from restaurant grease traps provides the low-cost supply, followed by cellulosic ethanol and FT fuels. We assume that a portion of the biomass for these fuels comes from low-cost supplies that are waste residues or grown on marginal lands. Higher-cost biodiesel from soybean oil and corn-based ethanol

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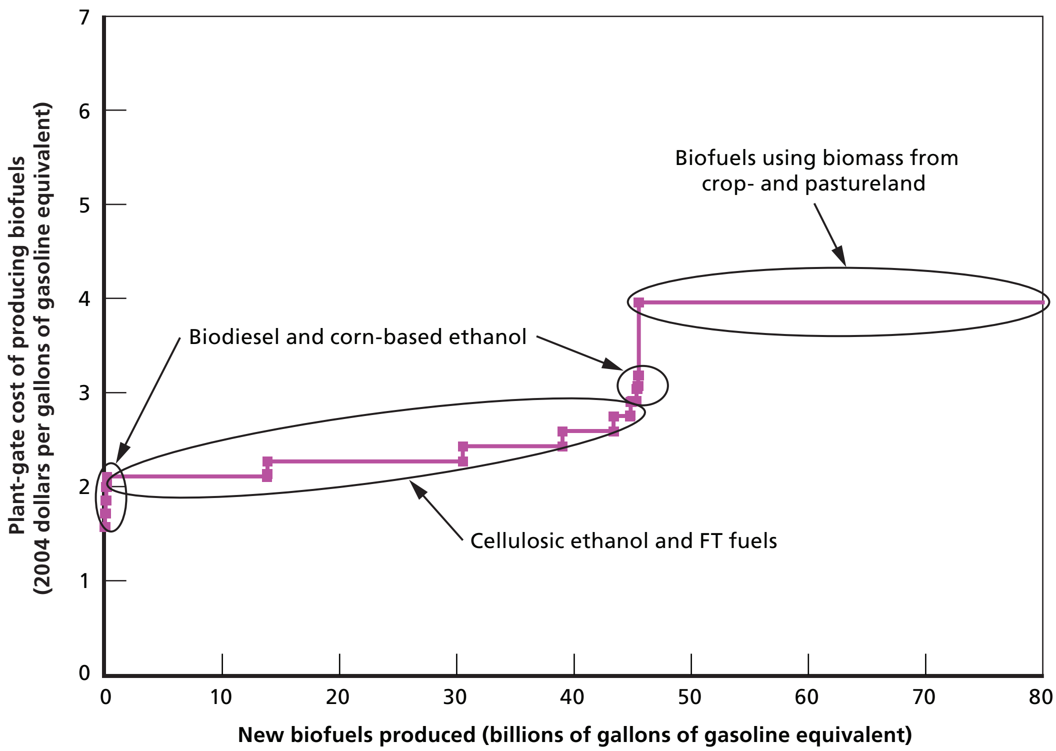
[7] This curve is not a "median" supply curve, since we make no assumptions in the scenario analysis about the relative likelihoods of different underlying parameter values.

Figure 2.1
Sample Biofuel Supply Curve Under One Set of Parameter Assumptions



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comprise the upper portion of the supply curve. These biofuels are produced with biomass grown on land converted from growing crops or grazing livestock. Under different assumptions, the curve changes shape, and technologies can occupy different relative positions.

After creating the aggregate supply curve, we calculate the marginal cost of renewable fuels by finding the point at which biofuel demand intersects the curve. Biofuel demand is the total demand for motor vehicle–transportation fuels multiplied by the renewable-energy requirement percentage. The marginal cost of meeting the requirement is the point at which biofuel demand intersects the supply curve. This intersection point also determines the relative mix of biofuels produced.

After calculating the amount of biofuel produced, we calculate the amount of oil displaced by biofuel production and the impact of this decrease in demand on the world price of oil. This change in the price of oil also results in a change in the price of gasoline and diesel fuel for consumers. We use a basic model of oil demand and supply that is benchmarked to data from DOE. The details on this model are in Appendix A.

In the fourth step, the model calculates the retail prices of biofuels and fossil fuels. When biofuels cost more than conventional fuels, as is typically the case in our scenarios, some government policy to equate delivered costs and thus prices is necessary if biofuels are to be used.[8] We allow for several potential mechanisms that affect differently the market prices that consumers see at the pump. One mechanism is a government subsidy to equalize the incremental

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[8] The need for such a pricing policy would be reduced if baseline oil prices were well above the reference-case values that we assumed.

cost of biofuels with conventional fuels. A second is a revenue-neutral tax-and-subsidy policy under which fossil-fuel taxes generate the needed revenue to subsidize the amount of biofuel to meet the policy requirement. A third is a tax on fossil fuels that equalizes the price of fossil fuels and biofuels.

An example may help demonstrate how these pricing mechanisms work. Suppose that the fossil fuel (gasoline or diesel) costs $1 per gallon and a biofuel alternative costs $2 per gallon in energy-equivalent terms. Ignore any impacts on crude-oil prices. Under the subsidy program, the government would pay biofuel producers $1 for each gallon produced, and, thus, the market price of fuels would be $1 per gallon. Total expenditure impacts would include the consumer and government outlays. With the fossil-fuel tax, the government would assess a $1 tax on each gallon of fossil fuel sold, and the market price of fuels would be $2 per gallon. Direct impacts on consumer outlays would include the tax, but the net effect would be calculated assuming that the government would rebate the tax rather than accrue revenue.

In the revenue-neutral tax-and-subsidy system, each fossil-fuel gallon is taxed by an amount such that the total tax collected on each three gallons is enough to cross-subsidize a gallon of renewable fuel to achieve the same price. Since there is a $1-per-gallon cost difference, if each fossil producer is taxed $0.25 per gallon, then a $0.75 subsidy per gallon of renewable fuel can equalize the price of the two fuels at $1.25 per gallon. The example shows that the pricing mechanisms significantly affect the prices that consumers see at the pump for the same underlying set of cost factors; they, therefore, have important implications for consumer behavior and energy expenditures.

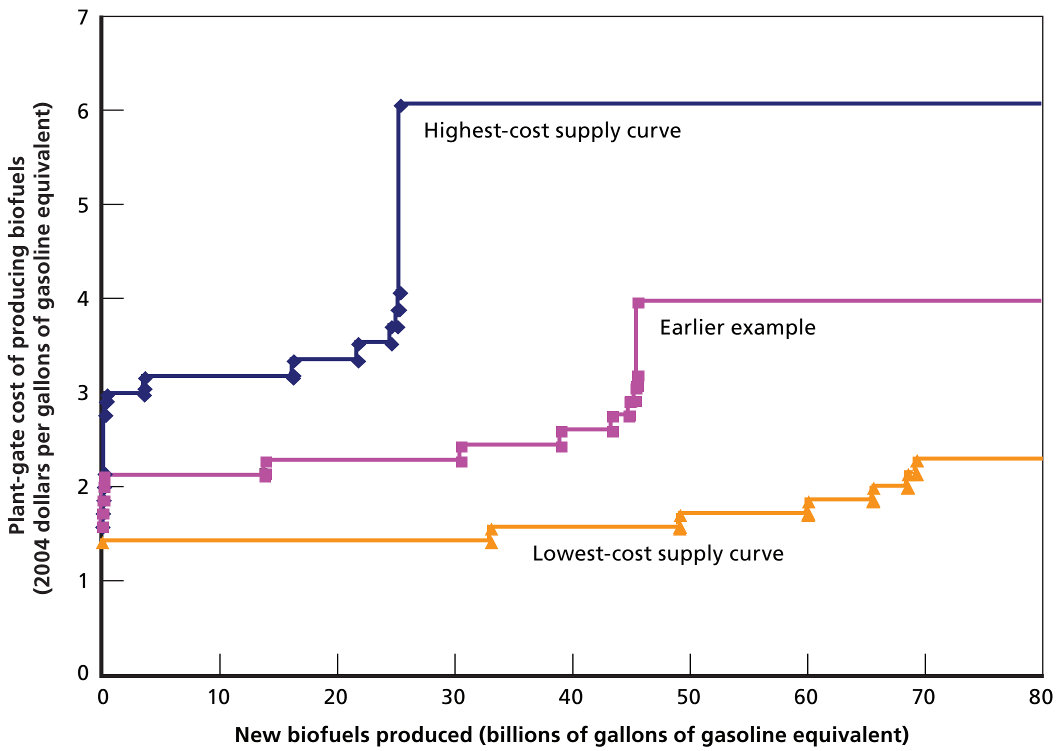
In the final step, the model uses a representation of motor-fuel demand to calculate the change in demand as prices change. In our analysis, we consider a subset of the transportation sector. We look at the demand for light-duty vehicles, commercial trucks, and freight transport. This represents the vast majority of gasoline and diesel demand in the transport sector. We targeted these markets because they already have some use of biofuels and because we assume, in the initial stages of this policy, that biofuel use will expand in markets in which production already occurs.

In our analysis, we allow for a wide range of the key variables influencing biofuel costs. Figure 2.2 illustrates the range of biofuel supply curves used in the analysis (see Appendix A for details).

Each curve shows the marginal cost of producing a particular level of biofuel. (As before, all figures in the diagram represent plant-gate costs; costs of distribution, marketing, and taxes are added subsequently.) The supply curve in the middle represents the earlier sample curve shown in Figure 2.1. The highest-cost supply curve uses the most-pessimistic assumptions in the range assumed for the analysis, while the lowest-cost supply curve uses the most-optimistic assumptions. By way of comparison, the 2006 AEO reference case projects the wholesale price of gasoline in 2025 at $1.53 per gallon (EIA, 2006b). The key parameters that affect the biofuel supply curves are the supply of low-cost biomass feedstock, yield of biofuel per unit of biomass, conversion costs of producing biofuels, and feedstock price for biomass from land conversion. We consider biomass to be low cost if it is available at less than $90 per ton, reflecting relatively inexpensive biomass supplies from wastes and marginal lands.

In our analysis, each scenario we run in the model uses a particular combination of input parameters that constructs a supply curve within the range shown in Figure 2.2. We can, therefore, explore the implications of uncertainty about these parameters on the cost of meeting a 25 percent renewable-energy requirement.

Figure 2.2
Range of Biofuel Supply Curves Used in Analysis



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As shown in Figure 2.2, each of the biofuel supply curves reaches a "backstop" cost at which any remaining demand can be filled. This backstop occurs after the supply of lower-cost biomass is fully used. The backstop biofuel supplies could be produced by converting existing agricultural land or pastureland into energy crops. Alternatively, the backstop could reflect the availability of imported biofuels. While Figure 2.2 shows the incremental cost of biofuels rising continuously to the backstop, in the implementation of the model, we allow for the cost of backstop biofuel supplies to be uncertain and potentially much higher than the cost of biofuels with lower-cost biomass. We examine further the nature of the backstop later, in our discussion of biomass supply.

Electricity Model

The electricity model follows the same basic steps as described already. However, we include some particular features to account for the characteristics of electricity demand and supply. Electricity requires different treatment because of the technical characteristics of the technologies. Some renewable sources, such as a dedicated biomass power plant, provide firm power that a system operator can control. Other technologies, such as wind, are intermittent and produce electricity only when the resource is available.

We assess the expenditure impacts by determining the *incremental costs of substituting renewable energy for nonrenewable sources in the system*. This substitution reflects the use of both new renewable capacity in lieu of nonrenewable capacity and fuel substitution. With respect to the former, DOE projects that about 160 gigawatts (GW) of new electricity capacity, of which renewables comprise about 6 percent, will come online between 2010 and 2025 to replace aging plants and meet growth in electricity demand. Our analysis looks at the cost of using renewable electricity instead of nonrenewable sources in these new plants.

In our analysis, we include electricity produced by onshore wind turbines, geothermal, dedicated biomass plants, coal plants co-fired with biomass, and solar-thermal power plants. We begin with the AEO 2006 reference assumptions about technology costs, electricity generation and prices, and addition of new capacity (EIA, 2006b).

In the first step of the analysis, we determine the incremental substitution costs of bringing more renewable energy into the electricity system to satisfy the 25 percent requirement. To do this, we calculate, for each technology, the difference in the real levelized cost of electricity (LCOE)[9] between the renewable technology and the nonrenewable alternative(s). This calculation also addresses the renewable capacity available to make the indicated substitution. The calculation takes a different form depending on whether the renewable electricity source is firm capacity (such as dedicated biomass), a fuel-switching technology (such as co-firing), or an intermittent source (such as wind). Each of these technology types has a differing ability to offset nonrenewable capacity, and the methods for calculating their incremental substitution costs vary, as specified in Appendix A. In our analysis, we use estimates from EIA and various sources in the literature on renewable-energy technologies to develop a range of potential technology costs reflecting uncertainty about the future.

After estimating the incremental substitution costs for each technology, we aggregate the estimates into a single incremental cost of renewables substitution curve. Figure 2.3 shows an example of this curve based on one set of parameter assumptions.

As we calculate the incremental costs of substituting renewables and the available capacity for each technology, Figure 2.3 shows the technologies that comprise the increasing incremental costs of substitution. Biomass supplies electricity in three ways, which is illustrated in the figure: Biofuel refineries can produce excess electricity that is exported to the grid, as illustrated at "Biofuel co-production"; the other two biomass renewable electricity sources are dedicated biomass plants and coal plants that mix biomass with coal (biomass co-firing). In this example, geothermal, dedicated biomass, and co-firing have modest amounts of new generation with relatively low incremental substitution costs. Wind has a large amount of available capacity but higher incremental substitution costs, even though, in some cases, it has lower marginal costs than biomass. Then, there is a significant component of dedicated biomass and co-firing that could come from biomass produced through land conversion: expensive biomass. Finally, solar thermal and high-cost wind comprise the last portions of the supply curve in this example.

The incremental substitution cost calculation accounts for the ability of a renewable technology to substitute for both nonrenewable capacity and fuel. Because biomass is a firm power technology, it directly substitutes for nonrenewable plant capacity and fuel use. Wind is intermittent and fully displaces fuel use but can only partially displace nonrenewable capacity. For these reasons, the firm and intermittent technologies displace nonrenewable capital costs differently. This incremental cost of substitution calculation is explained in greater detail in Appendix A.

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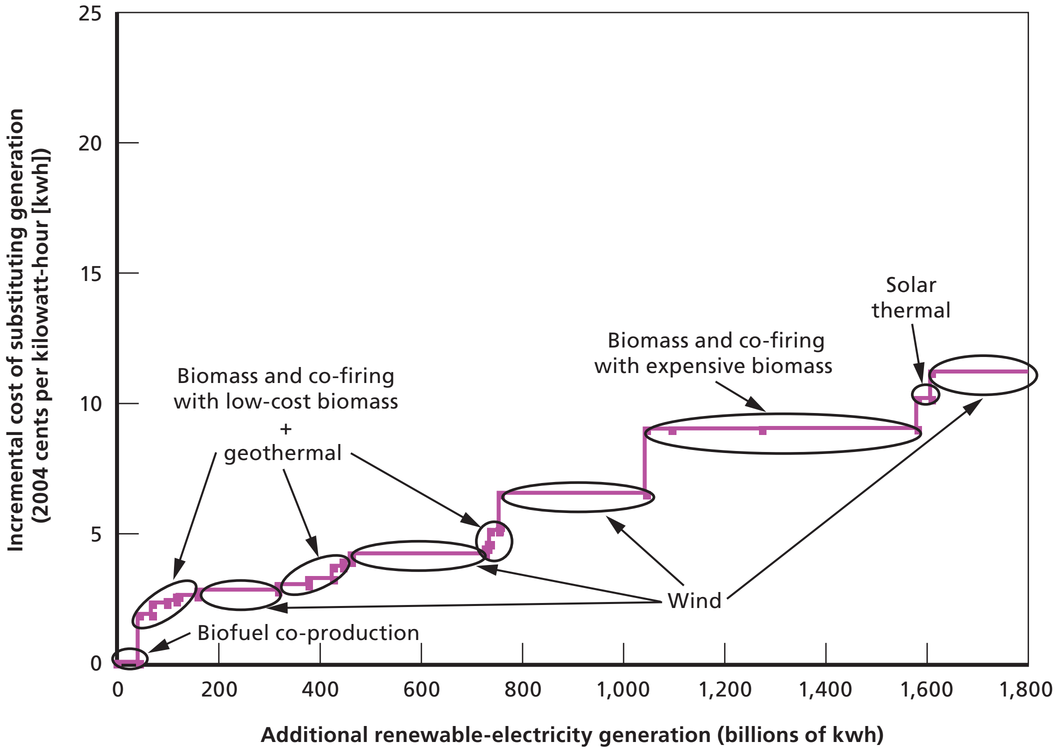
[9] The LCOE is "the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation)" (EIA, undated).

Figure 2.3
Sample Incremental Cost of Renewables Substitution Curve Under One Set of Parameter Assumptions



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We calculate the added expenditure associated with producing renewable electricity to meet the requirement by multiplying the net demand for new renewable electricity by the incremental cost of substituting renewables to meet the demand. This means that the most expensive renewable electricity source used effectively determines the total payment made for the additions of renewable electricity to meet the requirement. This approach reflects an assumption that electricity suppliers would have limited ability to price-discriminate in payments to different electricity producers for comparable (e.g., base-load) supplies. This would be the case, for example, if the added renewable supplies were purchased from independent power producers in a relatively competitive wholesale market. Total payments to suppliers for the added renewables, and thus the total impact on consumer expenditures, would be lower if we assumed instead that a traditional, vertically integrated utility produced the renewables and recovered its costs through average-cost pricing or rolled the costs of different purchases into average-cost rates. We discuss the implications of this for our findings in Chapter Three.

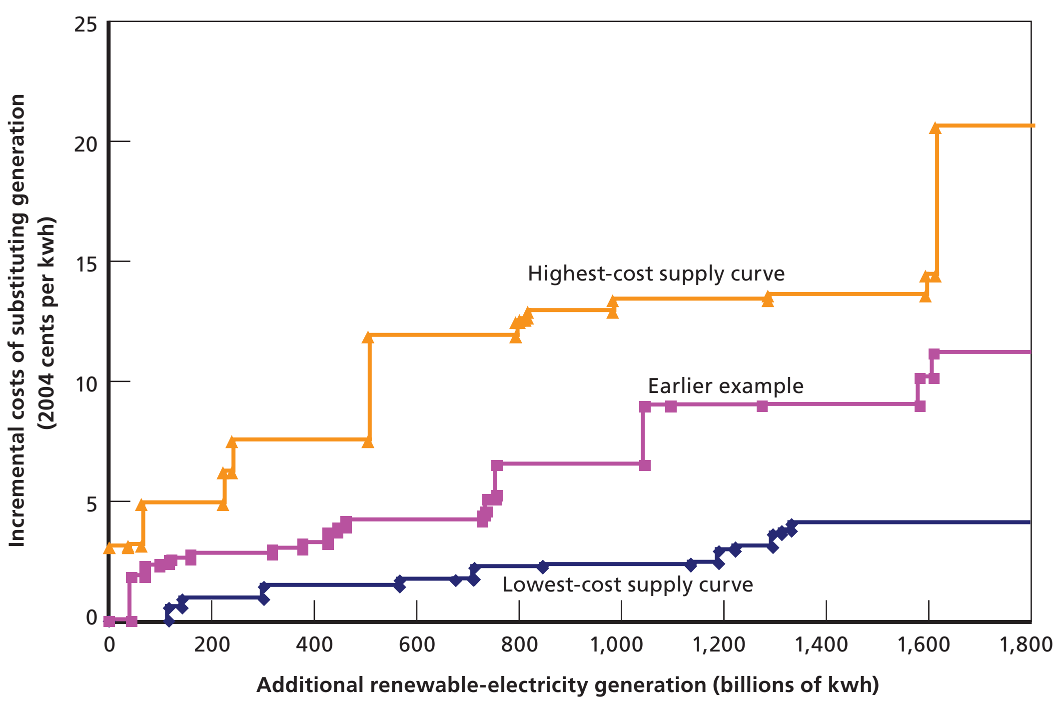
In the next step, we determine how adding renewables changes coal and natural gas prices by calculating the reduction in demand for coal and natural gas and then corresponding drops in their prices, based on simplified supply curve representations of these primary energy resources and nonelectric demand for natural gas. This information is incorporated into the cost of nonrenewable generation and yields a savings for consumers. It also increases the incremental cost of renewable energy.

After determining the expenditure changes for fossil and renewable electricity, we calculate an end-use electricity price as a weighted average expenditure. This fairly crude approach assumes that retail pricing does roll more-costly renewables into an average price for final consumers. With this new electricity price, we calculate the corresponding change in electricity demand with a basic equation calibrated to EIA data.

Figure 2.4 illustrates the range of assumptions used in the electricity market. As was true for the fuel market, the upper curve in the figure illustrates highest-substitution-cost assumptions about future renewable-electricity technology costs, and the lower curve shows the lowest-substitution-cost assumptions. The curve in the middle represents the sample case shown in Figure 2.3. In our analysis, we vary parameters to construct curves within the range bounded by the two shown in Figure 2.4.

Figures 2.3 and 2.4 show several important features. In the most optimistic case, incremental costs increase very little with additional generation. This occurs because substantial low-cost biomass supplies are available and wind costs grow minimally. In the middle curve, less low-cost biomass is available, and no low-cost biomass or biofuel co-production is available in the most pessimistic case. A second key feature is that wind can provide a large amount of renewable electricity and that the shape of the incremental cost of substitution curve is driven largely by assumptions about how wind costs rise with capacity increases. In our analysis, we follow EIA assumptions and use five cost steps to represent the cost of wind at different levels of installed capacity beyond baseline projections (shown by the four portions of the curve labeled "Wind" in Figure 2.3 plus one step not shown in the figure that was used in the baseline level of wind capacity). In the analysis, we allow the differences between these cost levels to increase and decrease, which is shown in Figure 2.4. In the bottom curve, wind costs

Figure 2.4
Range of Incremental Cost of Renewables Substitution Curves



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increase much less rapidly than they do in the upper curve. Because wind has much larger potential capacity than other renewable-energy technologies have, this assumption about wind costs has a large impact on the overall shape of the curve.

Biomass Feedstock Supply

With 25 percent renewable-energy requirements in the motor-fuel and electricity sectors, both sectors compete for a common biomass feedstock supply in a competitive feedstock market. Therefore, a critical issue in the expenditures analysis is the cost of greatly increased biomass supply. The biomass used for cellulosic ethanol and liquefaction is expected to come from wastes from agriculture, forestry, and urban areas, as well as from dedicated energy crops. In the best case, sufficient waste material exists, dedicated crops can be grown on lands that are not currently in production, and the biomass from these sources can be grown, collected, and transported inexpensively. However, if the amount of waste material and dedicated crops grown on unused lands is limited, then competition between biofuel refineries and power plants will bid up the price of biomass and induce landowners to convert their land to producing energy crops. Under this scenario, the renewable-energy requirements could significantly increase consumer energy expenditures and have considerable unintended consequences on land and food markets.

We found very limited analysis on potential biomass supplies and costs at the scale needed for a 25 percent renewable-energy requirement. The EIA uses one set of estimates in its analysis for the AEO. Researchers at Oak Ridge National Laboratory produced a biomass supply curve in 1999 (Graham and Walsh, 1999) that was under revision as this study was being prepared. These analyses presume that current market conditions apply in the future. The supply curves in both sources do not embody the range of potential innovation that could occur in the presence of a renewable-energy policy that mandates significant new investment into the bioenergy sector.[10]

Other researchers have assessed the feasibility, but not the cost, of a large-scale biomass supply. A recent joint study with the U.S. Department of Agriculture (USDA) and DOE, known as the Billion Ton Study, estimated that the U.S. agricultural and forestry sectors can expand to supply more than 1 billion tons of biomass annually without large-scale changes in existing land uses (Perlack et al., 2005). This amount of biomass is more than sufficient to supply both the electricity and biofuel markets. However, a key limitation of the study is that it did not provide quantitative estimates of the costs of producing, gathering, and delivering this level of biomass.

A basic example highlights the challenges that biomass substitution would pose for the agricultural sector. Using EIA's 2006 projection for fuel demand in the sectors considered in this analysis, a 25 percent requirement entails 51.6 billion gallons of biofuels (in gasoline-equivalent units). Assuming our middle-range figure for biofuel yield (90 gallons per ton of feedstock), meeting this demand with ethanol would require more than 850 million tons of biomass feedstock. This is almost double EIA's current estimate of biomass feedstock supply

[10] While preparing this report, other RAND research assessing the *current* costs of delivering biomass for use in a coal biomass–to-liquid plant calculated higher costs than did other commonly cited estimates (Ortiz, 2008). Those findings indicate how achieving any large-scale production of low-cost biomass by 2025 will require continued innovation.

(430 million tons) but less than the billion-ton estimate. Achieving a large and low-cost biomass supply will require significant innovation in producing energy crops. If that does not occur, then costs will be higher, and land-use conversion, possibly on a very large scale, would be needed to meet the requirement.

With this level of uncertainty in the biomass supply and potential cost, we did not try to identify a most likely estimate of feedstock costs. Developing a full-scale model of U.S. land-use supply was also beyond the scope of our analysis. Instead, we defined a range of possible biomass supply curves for 2025, based on existing estimates. This range makes it possible to identify some of the necessary conditions for biomass supply so that the 25 percent requirements can be achieved with a limited expenditure impact.

We assume a range of potential low-cost biomass supplies, from 450 million tons to 1 billion tons. Our lower limit is slightly greater than EIA's current estimate of biomass supply (about 430 million tons), which is currently under revision. The upper limit is based on a DOE/USDA joint study on the feasibility of a billion-ton biomass supply (Perlack et al., 2005).

Once the low-cost biomass supplies are exhausted, we assume that biomass will be cultivated and harvested on land currently used for agriculture, pasture, or forestry. Biomass from these supplies are higher-cost resources in the supply curve, even though the land is productive, because there is a high opportunity cost of converting the land and forgoing the revenue from the current use. There is a wide range of these opportunity costs because of the differences in their productivities in alternative uses and uncertainties in the costs of profitably converting different categories of land, as discussed further in Appendix A.

We simplify the representation of these potential resources by treating them as a backstop 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. Some calculations in Appendix A using current estimates of land rents and production costs suggest that a cost of $90 per ton is a reasonable lower bound for the backstop. Rather than just setting the backstop price at $90 per ton, however, we assume a range of potential costs for backstop supplies from $90 to $200 per ton. Since the market price of biomass will depend on the cost of the marginal unit supplied, this simple representation of the backstop allows us to incorporate uncertainty about how much land is converted and its opportunity cost without having to build a full model of competing land uses and values, which is beyond the scope of this study.

Beyond additional domestic resources through land conversion, the country also could rely on expanded imports of biofuels at a future price that also is uncertain. It will depend, in particular, on how international demand for biofuels might grow over the next 20 years. When we represent the biofuel (versus biomass) supply curve as in Figure 2.2, the backstop can reflect either fuel production using domestic backstop biomass or fuel imports as the marginal source of supply. In our calculations of potential land conversion, however, we assume that all the backstop biomass is domestically produced.

Elasticities of Energy Demands and Primary Energy Supplies

As explained further in Appendix A, a key part of our sensitivity analysis is the incorporation of different possible values for key price elasticities of supply and demand. The literature on energy demand and supply does not provide consensus-point estimates for these elasticities.[11] Table 2.1 summarizes the assumed ranges of elasticities whose values we varied. Three other elasticities were set at fixed values to simplify the analysis. These were the elasticities of non-electric natural gas demand and nontransportation oil demand in the United States and the elasticity of non-U.S. total oil demand. The first two elasticities were set at –0.5; the third was set at –0.4.

The elasticities we use are intended to be long-term elasticities, since we are using them to reflect the situation in 2025 assuming full adjustment to the renewables requirements. The values for transportation fuel demand comport with those found in the literature.[12] The literatures on natural gas and electricity demand are somewhat more sparse, but there appears to be broad agreement that demands for these energy sources are no more elastic than is transportation-fuel demand.

We particularly single out for comment the range of elasticities assumed for world oil supply. There is debate first on whether the concept of elasticity is well defined for this supply, given the influence of members of the Organization of the Petroleum Exporting Countries (OPEC) on the market. In this analysis, we do not try to directly simulate the behavior of OPEC in response to a change in world demand for oil as the United States increases renewable-fuel use. Instead, we use a range of elasticities that can be thought of as implicitly reflecting the different adjustments of both OPEC and non-OPEC suppliers to the change in demand. With respect to non-OPEC suppliers, oil supply elasticities on the low end of the assumed range could be thought of as reflecting higher costs for crude-oil production.

The literature on natural gas supply elasticities also is limited. For that reason, we chose to use the same range of elasticities for natural gas as for crude oil. The assumed range of natural gas supply elasticities is consistent with recent modeling analyses of the North American natural gas market (Energy Modeling Forum, 2003). Coal supply, in contrast, was assumed to be more price-elastic over the longer term, with more opportunities for significant new supplies as prices rise and more ability to shut in resources as prices fall.

Table 2.1
Assumed Price-Elasticity Values

	Elasticity Value		
Energy Supply or Demand Type	**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

[11] *Price elasticity* is defined as the percentage change in demand or supply relative to a percentage change in price. Thus, a demand elasticity of –0.5 means that a 10 percent increase in price will lead to only a 5 percent drop in demand.

[12] Bartis, Camm, and Ortiz (forthcoming) review this literature.

Conducting the Analysis

In conducting the analysis, we use the outputs of these models to calculate the impacts of meeting the renewables requirements on energy expenditures and CO_2 emissions. We also conduct an uncertainty analysis that allows us to determine which of the uncertainties in the energy-expenditure impact analysis are key in driving the results we see. We describe each analysis briefly here.

Analysis of Impacts on Energy Expenditures

The change in net consumer energy expenditures includes changes in expenditures on electricity and motor-transportation fuels because of the renewable-energy requirement. We add any other government expenditures made on subsidizing renewable energy and net out any increases in government revenue from taxes on fossil fuels (under the relevant pricing policies). We also include decreases in expenditures on fossil fuels in electricity and transportation markets and in nonelectricity and nontransportation consumers of natural gas and oil. As noted already, the expenditure metric does not address the broader implications for consumer well-being of higher costs for other goods and services as a consequence of more expensive energy. Nor does it address the potential impacts on food costs of increased biomass-energy production.

Analysis of Impacts on CO_2 Emissions

To measure changes in CO_2 emissions from a renewable-energy requirement, we use estimates of the life-cycle emissions for the renewable and nonrenewable technologies drawn from various sources, as described in Appendix A. These values are treated as fixed in the uncertainty analysis, and they do not incorporate the possible release of CO_2 stored in soils when biomass feedstock production is increased. From these values, we calculate the change in emissions by substituting renewable energy for nonrenewable sources. In addition, we calculate the change in emissions from any conservation effects of the requirement. Energy-price increases lead to demand decreases, and this induced energy conservation reduces CO_2 emissions. In the model, we account for both the substitution and conservation portions of total CO_2 emission change. We also report the incremental energy costs divided by the total CO_2 reduction. This metric indicates the additional costs of using renewable energy to reduce CO_2 emissions and is a measure of the cost-effectiveness of the policy requirement.

Uncertainty Analysis

A traditional approach to energy simulation involves a relatively small number of future scenarios: often a most likely base case and several excursions. This study takes a different analytic approach. Based on the ideas of exploratory modeling (Bankes, 1993; Metz et al., 2001) and "scenario-discovery" (Groves and Lempert, 2007; Lempert et al., 2006), we run the model over a wide range of plausible assumptions in order to identify the most important factors determining the costs resulting from the 25 percent renewables requirements.

Our analysis implements the following three steps:

- Develop plausible ranges for each of 19 key input parameters to the model. These ranges are summarized in Table A.24 in Appendix A.

- Use the model to evaluate the change in energy expenditures resulting from the 25 percent renewable-energy requirements for more than 1,000 different combinations of assumptions about the values of the input parameters.
- Identify which combinations of a few input factors are most important in influencing the expenditure impact of the 25 percent renewables requirements.

In the first step of the analysis, we use information from previous studies, technical reports, and industry experts to define plausible ranges for key variables in the analysis, such as future technology costs. The ranges for these variables are defined broadly to capture the breadth of views on key uncertainties. We make no probabilistic assumptions over the ranges of values used in the analysis. Rather, our goal is to explore the cost implications of the full range of assumptions found in the literature and public debate.

In the second step, we use the model to evaluate the expenditure impacts and emission reductions resulting from a 25 percent renewable-energy requirement in each of thousands of cases using different combinations of values for the key variables in the analysis. We use statistical methods to choose a set of cases that efficiently samples the entire range of possible outcomes. Because we make no judgments about the relative probabilities to be attached to different combinations of parameters, this sampling does *not* indicate the relative likelihood of different expenditures and emission impacts.

In the third step, we use these model runs to identify which combinations of a few input parameters are most important in determining the expenditure impacts of a 25 percent renewables requirement. We first separate out two groups of model runs that contain the lowest and highest 10 percent of expenditure changes, respectively. We then conduct a statistical scenario-discovery analysis to identify which combinations of the input parameters are key factors in determining each outcome.

The quantitative range of expenditure chosen to define these groups reflects a combination of (1) the authors' judgments about the levels that consumers might regard as relatively minor or prohibitively excessive and (2) the need to have enough cases in each group to support our statistical analysis. While these ranges are thus ad hoc, the study's results should not be overly sensitive to the ranges of high and low expenditures considered.

Concluding Remarks

While the structure of this study's model remains very simplified relative to the real-world complexities of energy production, investment, and consumption decisions, we believe that it provides a qualitatively reliable snapshot of the expenditure and CO_2 impacts from different renewables requirements for electricity and fuels and for identifying the most important factors in determining the impacts of such a renewables requirement. It is important to note, however, that the model's snapshot-like perspective on alternative scenarios in 2025 presumes that technically feasible paths exist for achieving, over the next 20 years, levels of renewable-nergy use significantly larger than would be anticipated using EIA business-as-usual scenarios.[13] Moreover, the focus on steady-state comparisons in 2025 does not provide information on the costs

[13] As discussed in Chapter Three, the 25 percent levels of renewables usage being considered here are larger than business as usual in a number of other prognostications as well.

of adjustment that might be incurred for such significant changes in patterns of renewable-energy use—in particular, the significant costs of new plant investment and the high costs per unit of output for initial investment prior to realizing cost decreases through learning. Therefore, it is crucial to keep in mind that the results presented in Chapter Three probably represent lower bounds for the direct impacts on expenditure resulting from achieving significant increases in renewables use over the next 20 years.

CHAPTER THREE

Key Findings

In this chapter, we present the key findings that are derived from our analysis of the 25 percent renewable-energy requirements. In summary, we found the following:

- Substantial variation exists in expenditure impacts across different sets of assumptions, especially in the motor-vehicle transportation–fuel market. Depending on the assumptions made, expenditure changes can be minimal or show a very substantial increase.
- The government's approach to implementation of the policy requirements—particularly with respect to motor-fuel pricing—has important effects on consumer behavior and expenditures. In particular, passing the cost of more expensive renewable fuels to final pump prices will also increase the direct impact on expenditure, but it will serve as well to generate improvements in energy efficiency. Subsidizing more expensive fuels will mitigate the direct impact on expenditure for consumers, but only by transferring the expenditure to the government budget.
- Meeting the 25 percent requirements with relatively low expenditure impacts requires significant progress concurrently in several aspects of renewable-energy technologies. Biomass availability, in particular, is one of the factors that can have the greatest implications for consumer expenditure changes. Another important factor is the degree to which technical advances in wind power will make it possible to use lower-quality sites without a major increase in cost. DOE has set ambitious program goals for renewable technologies that, if achieved, would significantly moderate the expenditure impact of the 25 percent requirements. But if progress falls short of this set of goals, the requirements could be expensive. This is a real possibility, given not just the ambitiousness of the goals but also the general tendency for technology-development programs to have optimistic early stage cost estimates.
- Lower levels of the requirements (15 or 20 percent) decrease expenditure changes more than proportionately, although they also result in lower CO_2 emission reductions than do the 25 percent requirements.
- Higher baseline energy prices reduce the relative cost of achieving the 25 percent requirements, though they also reduce the need for establishing these requirements as policy targets.
- The 25 percent requirements can reduce CO_2 emissions significantly, but the additional cost of energy supply per unit of reduced CO_2 emissions can vary considerably. Unless there is very substantial cost-reducing technical innovation for expanding renewables, the incremental cost could be high relative to the incremental costs often encountered in current policy discussions for CO_2 mitigation.

In the remainder of this chapter, we explain these findings and show our model results supporting them.

Substantial Variation in Expenditure Change Impacts, Especially for Biofuels

The expenditure change with 25 percent renewable-energy requirements varies substantially across our scenarios, particularly in the motor-vehicle transportation–fuel sector. The large variability in the expenditure change outcomes reflects the substantial uncertainties in the future costs of renewable technologies *at the level of capacity needed to meet a 25 percent requirement in both markets*. Some of the technologies, such as wind power, are relatively well established and in commercial production today; however, even these technologies are currently used at a small fraction of the capacity needed to meet a 25 percent requirement, and how the costs of these technologies change as capacity deployed increases is still a significant uncertainty. Several other technologies, such as cellulosic ethanol and electricity produced in a biomass integrated gasification combined-cycle (IGCC)[1] power plant, are expected to have a major role in meeting this requirement, but these technologies are currently in a precommercial state. The costs of building a first-of-a-kind commercial plant, how these technology costs decline through learning, and biomass feedstock costs at high capacities are all large uncertainties that affect the costs of these technologies.

In our analysis, we found that, with significant and broad progress in renewable-energy technologies, the 25 percent requirements have limited impacts on consumer energy expenditures. However, if key technologies and biomass supplies are costly at high levels of deployment, then energy-expenditure impacts can become very large. In subsequent parts of this chapter, we describe the key factors leading to these different outcomes and the ranges of values for these factors that lead to both outcomes. Here, we show the ranges of outcomes in each market, summarize the results, and compare them with a recent EIA study of a similar requirement.

Electricity

Figures 3.1 through 3.5 summarize the range of impacts on expenditure changes, energy consumption, and prices in the fuel and electricity markets. Note that this analysis makes no assumptions about the likelihood of each scenario. The reader should not use the figures to infer probabilities of a particular outcome. Instead, the figures reflect the frequency of occurrence of expenditure impacts, given our collection of scenarios.

Figure 3.1 displays energy consumption and expenditure changes in the electricity market, where the y-axis shows electricity consumption as a percentage of the reference level and the x-axis shows the net consumer expenditure change. Each point in the figure displays the result of one case from the thousands that we considered.[2] We also show EIA's estimate of electricity

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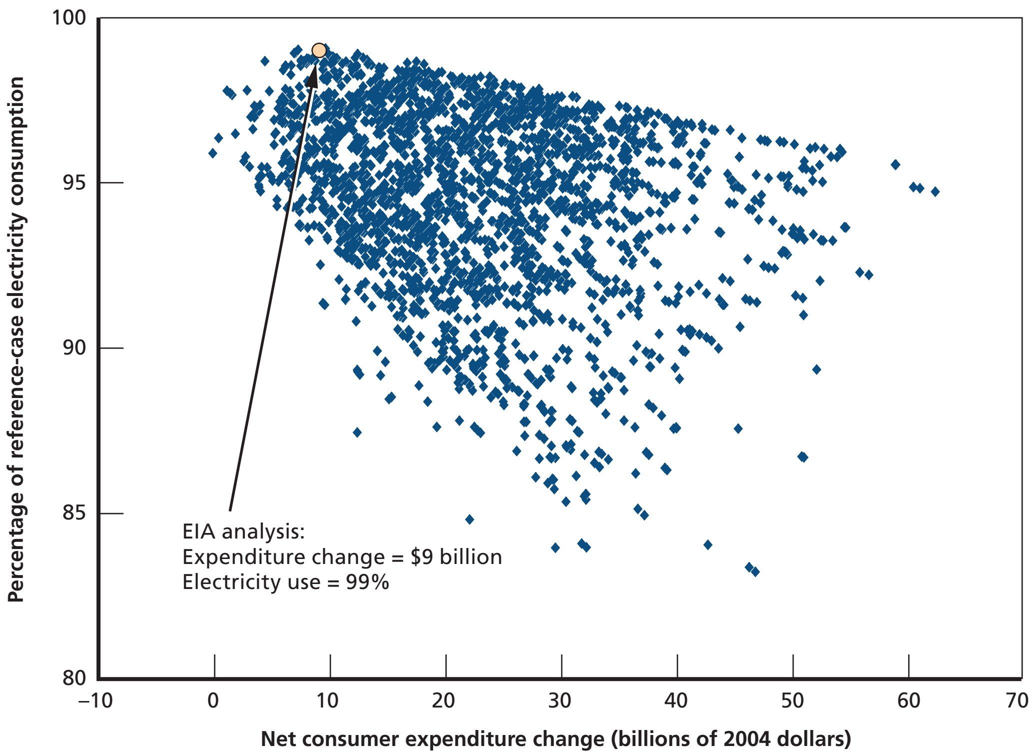
1 An *IGCC power plant* is one in which the feedstock (coal or biomass) is converted into a gas, from which pollutants can be removed more easily and then fed into a combined-cycle system.

2 We ran 3,000 combinations of parameter assumptions (1,000 for each pricing mechanism). Some input combinations fail to meet certain technical criteria for numerical convergence of the model's iteration algorithm and are excluded from the results. After this exclusion, we have 2,582 total cases. For details on how we selected the 1,000 cases for each pricing mechanism, see Appendix A.

Figure 3.1
Range of Expenditure and Consumption Changes in the Electricity Market



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expenditure and consumption change from its recent analysis of a 25 percent renewable-energy requirement. We compare that estimate to our results in the discussion that follows.

Under the assumptions in this analysis, renewable electricity costs more than fossil-fuel alternatives, and electricity prices increase under the 25 percent requirement. The higher prices result in lower electricity consumption than those in the reference case. The resulting consumption change depends on the difference in costs between renewable and nonrenewable electricity and how consumers respond to rising prices. The net consumer expenditure change shown on the x-axis includes the higher consumer expenditures on renewable electricity and the offsetting decreases in fossil-fuel costs to electricity and nonelectricity consumers.

Our results show that expenditure changes for 2025 in the electricity market range from a decline of $0.1 billion to an increase of $62 billion from the reference case. The EIA AEO 2006 reference projection of electricity market expenditures is $368 billion; therefore, these results represent changes in electricity expenditures from 0 percent under the most favorable circumstances assumed to slightly less than 17 percent under the highest-cost assumptions.

The changes in energy consumption in Figure 3.1 provide an indirect indication of the overall social cost of the policy requirements that is not captured by the expenditure change metric. The reduction in energy services as electricity prices rise indicates the loss in utilization of a valuable input to production and consumer well-being. Under our range of scenarios, electricity consumption varies from 83 to 99 percent of the reference level. The higher end of the reductions (approaching 17 percent) indicates a particularly big drop, given that electricity demand is relatively price-inelastic (elasticities from –0.2 to –0.6). For a given level of expenditure change, the electricity consumption change can vary considerably, given different assumptions of demand elasticities in particular, and the range grows as the expenditure change increases.

We noted in Chapter Two that, in this analysis, all additional renewable-energy supplies are assumed to receive payment reflecting the incremental cost of the most costly renewable source needed to satisfy the 25 percent requirement for electricity. While this assumption would seem to realistically depict the situation that many utilities would face in acquiring additional renewables from independent producers, it does also imply a potentially significant transfer of economic surplus to less costly renewables suppliers from end users. Calculations of these rents indicate that their percentage of total payments for renewables varies widely but that, in many cases, the rent is on the order of 20–40 percent of the total payment. Total payments for the required renewables could be lower if utilities could price-discriminate in purchasing the energy or if they owned the facilities *and* were required to average all the high-cost resources into their overall rates.[3] This more traditional utility-pricing approach is somewhat at variance with movements toward more market-based pricing, however, especially in wholesale transactions.

In addition to the total expenditure impacts, we report in Figure 3.2 the range of average prices in the electricity market under the renewables requirement. The figure shows the percentage of scenarios in which average electricity prices assumed the values shown on the horizontal axis. For example, the first column shows the percentage of cases with average electricity prices of less than $0.0775 per kWh. The second column shows the percentage of cases from $0.0775 to $0.08 per kWh. These bars should *not* be interpreted as indicating probabilities, since we have not imposed any probabilities on the occurrence of different scenarios. In other words, if one believed that there was a high likelihood of limited progress in renewable electricity, then one would put the greatest emphasis on the scenarios with high average prices, even if their relative occurrence was low in our uniform sampling across the range of parameter values.

EIA's reference projection for average electricity price in 2025 is $0.074 per kWh. If technical advance for renewables is limited and demand is not able to respond very strongly to higher prices, then the average electricity price could rise to more than $0.10 per kWh, almost 40 percent over EIA's reference value. In scenarios with greater advance in renewables and more ability of demand to adjust to higher prices, average electricity prices could be less than $0.085 per kWh, about 15 percent greater than EIA's reference case.

We can consider the direct effects of these price increases on electricity payments for the average household. The direct effect looks only at electricity purchases and does not include the higher cost for other goods and services as a result of more expensive electricity. According to EIA's 2006 base-case projection, an average household would pay about $1,035 per year for electricity in 2025.[4] The effect of a rise in the average electricity price will depend on the elasticity of demand. Using a long-term elasticity of –0.4, the middle of our assumed range (see

[3] Without rate averaging, the utilities would garner the rents in setting their retail rates.

[4] Using EIA's projections of residential consumption (1.787 trillion kWh) and total households (145 million) in 2025, average household consumption is 12,234 kWh per household per year. The household electricity price is $0.084 per kWh, more than the overall economy average of $0.074 per kWh noted earlier.

Figure 3.2
Range of Average Electricity Prices

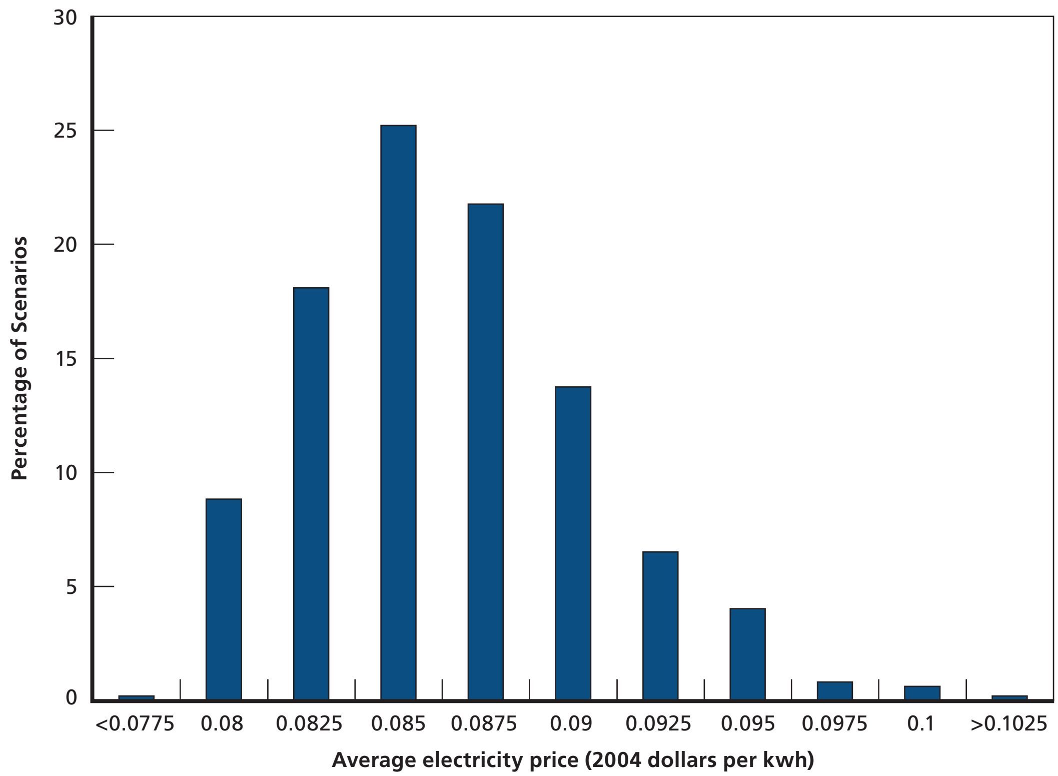

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Table A.18 in Appendix A), we find that, with a 15 percent increase in the average price, the direct household expenditure rises 9 percent, or $93 per year (just less than $8 per month).[5] A 40 percent increase in the average electricity price with the same elasticity implies a 24 percent increase in direct expenditures, or $248 per year (more than $20 per month). The magnitude would be larger (smaller) for larger (smaller) base levels of expenditures. A lower (higher) magnitude of the elasticity of demand also would imply a larger (smaller) direct impact on expenditure.

We can also make some simple calculations to very roughly illustrate the total (direct and indirect) impact of the renewable-electricity requirement per household. As noted, EIA's base-case projection of total electricity expenditure is $368 billion in 2025. A 5 percent increase in total expenditure would translate into about $127 per household per year; a 25 percent increase would translate into five times that amount, or about $635 per household per year. These calculations assume that all increases in electricity costs are passed forward to consumers. In practice, competition in the wholesale supply of electricity could result in some part of the higher costs being passed backward to shareholders of electricity utilities.

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[5] Using the definition of *elasticity*, it can be shown that the product of the percentage price increase and the (negative) elasticity provides the percentage decrease in quantity demanded and that the percentage change in expenditure is the net of these two changes. In this case, a 15 percent average price increase with a –0.4 elasticity implies a 6 percent decrease in consumption and a 9 percent increase in expenditure.

EIA also has released an analysis of a 25-percent-by-2025 policy using its National Energy Modeling System (NEMS) (DOE, 2007). In its policy-case scenario,[6] EIA projects that the renewable-energy policy requirements increase consumer-electricity expenditures by $9 billion in 2025, which is in the lower range of projections in our scenarios, as shown in Figure 3.1. EIA also considers two other scenarios: a high–energy-price scenario, with higher crude-oil and natural gas prices, and a high-technology case with more-rapid improvements in renewable-energy technologies. Under these cases, the expenditure changes are even lower as would be expected. In particular, with higher oil and gas prices, there will be more energy conservation and use of higher-cost fossil-energy resources in the absence of the requirement, so imposing it will add less to total energy expenditures.

In EIA's analysis, electricity from dedicated biomass plants is the single largest source of renewable electricity, accounting for 36 percent of the total renewable electricity supply. EIA's analysis allows for expanded use of corn-based ethanol and imports of ethanol from Brazil to meet demand for biofuels. This has the effect of limiting the use of U.S.-produced cellulosic ethanol in 2025, resulting in lower fuel supply costs and a larger biomass feedstock supply available at competitive prices for use in the electricity sector. In the EIA analysis, corn-based ethanol production exceeds 25 billion gallons and imports rise to more than 7 billion gallons. In previous years' energy outlooks, EIA placed limits on corn ethanol at about 11 billion gallons and less than 1 billion gallons of imported ethanol, assumptions that we maintained in our analysis. Consequently, dedicated biomass generation in our analysis is lower, because biomass feedstock prices are driven up by the large demand for feedstock in producing non–corn-based biofuels, and there is much greater need to rely on higher-cost wind resources.

We show a much wider range of outcomes than does EIA in the electricity market, and, as shown in Figure 3.1, our expenditure impacts tend to be significantly greater. In addition to the differences in biofuel availability just described, we also assume a wider range of values for key variables in the analysis to account for the significant uncertainties in such important factors as future technology costs and biomass supply. Even though renewable-electricity technologies are generally more mature than biofuel technologies, there are still large uncertainties in the costs of achieving a 25 percent penetration level. To meet this requirement, wind power will need to expand significantly from its current level of capacity, and the costs of developing more remote sites and those with lower-quality wind resources are very uncertain. Dedicated biomass generation in both EIA's analysis and in ours assumes IGCC power-plant technology that uses biomass instead of coal. This technology is feasible today and promising, because its components are in commercial use with other feedstocks. However, there is still considerable uncertainty about applying the technology with a biomass feedstock and deploying it at the scale needed to meet a 25 percent requirement. For these reasons, we assume a broad range of future costs to show the implications for a 25 percent policy requirement.

Fuels

Our analysis considers three pricing mechanisms for implementing the renewable-energy requirement in the motor-fuel market: a subsidy that reduces biofuel prices to the nonrenewable equivalent, a tax on fossil fuels that increases their prices to the level of biofuel prices, and

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[6] The policy case uses EIA's nominal assumptions about technology costs and fuel prices while imposing the policy requirement. EIA also analyzed other scenarios with alternative assumptions about technology costs, oil and gas prices, and ethanol imports.

a combination of the tax and subsidy that is revenue neutral for the government. In Figure 3.3, we show the implications of these different mechanisms for government and consumer expenditures under the cases we considered.

The y-axis of Figure 3.3 shows the change in government revenue, and the x-axis shows the change in consumer energy expenditures. Positive values of government revenue reflect revenue increases gained by taxing fossil fuels. Negative values of revenue indicate higher government expenditures to subsidize renewable fuels. The figure shows that the three mechanisms have very significant differences in impacts on consumer and government expenditures. The subsidy mechanism decreases consumer spending on motor fuels, because crude-oil prices decline as biofuel production increases, and all fuels are priced at the level of fossil fuels. Government revenues are negative, reflecting government outlays to subsidize renewable fuels.

The scenarios with the revenue-neutral tax-and-subsidy policy lie along the x-axis, showing consumer expenditure changes with no change in government revenue. The fossil-fuel tax results lie in the upper-right quadrant of the figure. Both consumer expenditures and government revenues increase under this mechanism. The magnitudes of the increases can be substantial in some cases, because renewable fuels can cost as much as two to three times more than fossil fuels at the 25 percent penetration level.

Figure 3.4 compares changes in motor-fuel consumption and *net* expenditures for the three pricing mechanisms across our set of results. We assume in the net expenditures

Figure 3.3
Range of Government and Consumer Expenditure Changes in the Motor-Vehicle Transportation–Fuel Market

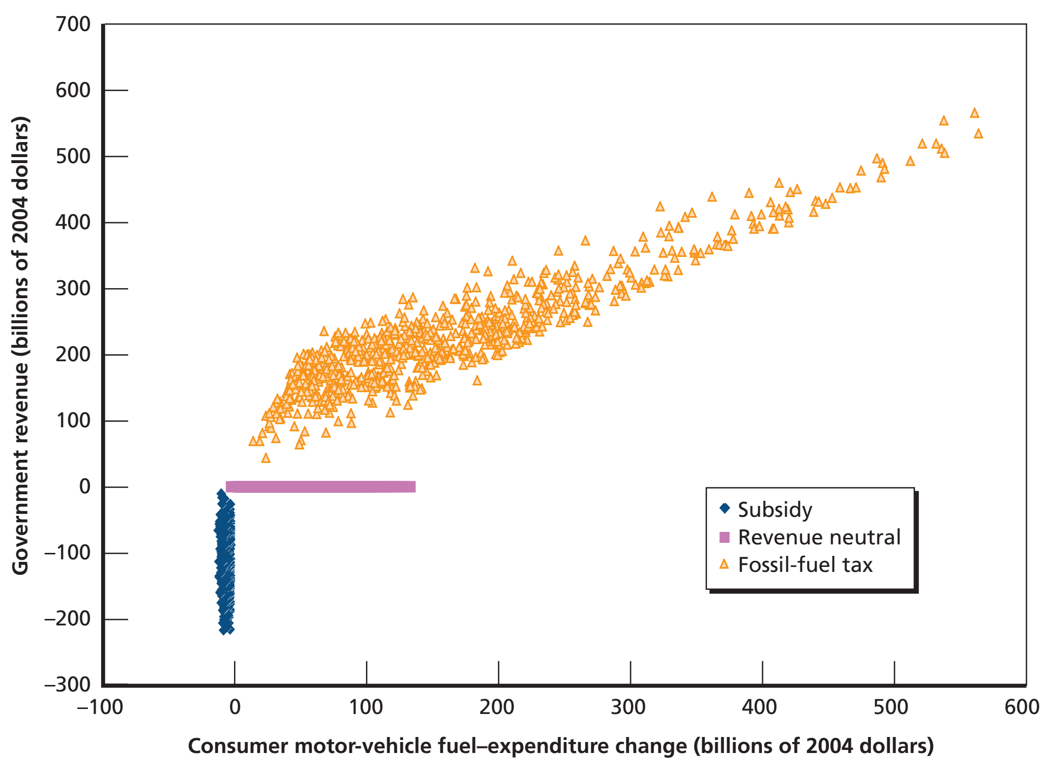

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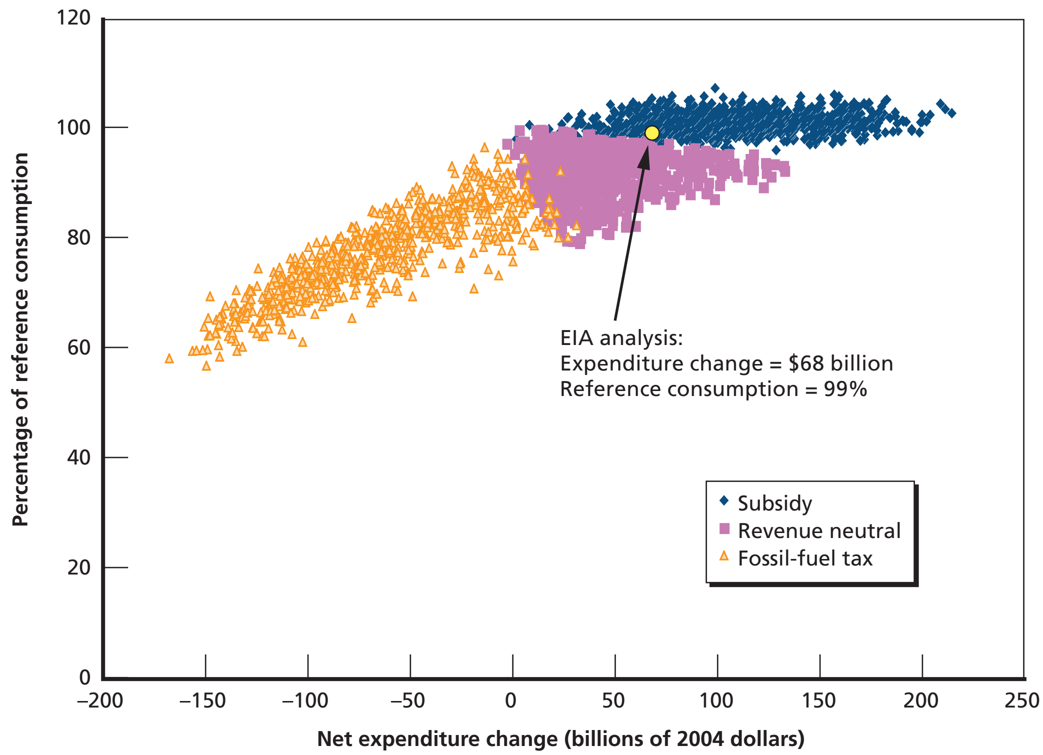
Figure 3.4
Range of Expenditure Changes in Motor-Vehicle Transportation–Fuel Market



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calculations that the government returns the revenue collected from the fossil-fuel tax to consumers and that consumers pay higher taxes to fund the biofuel subsidies.

The range of net expenditure changes in the transportation fuel market extends from a large net decrease ($168 billion) with a fossil-fuel tax to a significant increase ($214 billion) with a renewable-fuel subsidy. For comparison, the EIA AEO 2006 reference-case projection for consumer expenditures in 2025 is $491 billion. Thus, the upper end of the expenditure change in Figure 3.4 reflects an increase of more than 40 percent.

To interpret these results correctly, it is important to note that the negative expenditure change results do *not* imply consumers are necessarily better off under the taxation policy. The figure shows that the cases with large negative expenditure changes also have substantial declines in fuel consumption relative to the reference level as a consequence of the increase in all fuel prices. The consumption decrease moderates the consumer expenditure increase, but it also indicates a loss of societal benefit from the reduced fuel consumption. The reason that the fuel tax scenarios show negative net expenditure impacts is that the decrease in fossil-fuel demand feeds back on the world oil market to reduce the price of crude oil, and this reduces the price of conventional fuels. Since these fuels still represent 75 percent of (overall lower) fuel consumption, even a small decrease in their unit prices will generate significant savings. These savings, plus the revenue from the government's fossil-fuel tax, are larger than the increase—which consumers must bear—in total payments for fuels.

To put these numbers in perspective, note that a 5 percentage-point expenditure change in motor-vehicle transportation–fuel expenditures is about $25 billion, which results in an increase of about $169 in average annual expenditures per household (or just more than $14 per month, using EIA's projection of 145 million households). A 25 percent expenditure change is $123 billion, which equates to an increase of about $847 per year for the average household ($70 per month).

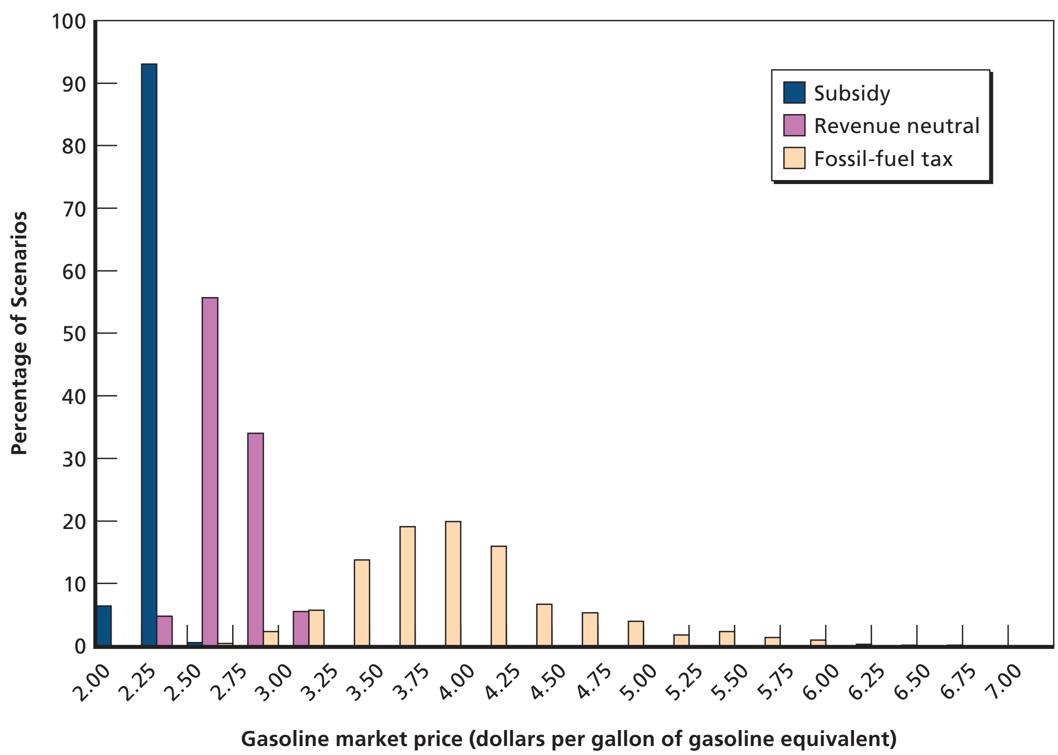
The range of expenditure results for this market is much greater than for electricity. This is because of the level of uncertainty over future biofuel technology costs and production capacity and the lack of other substitution options (domestically produced or imported).

We show in Figure 3.5 the consumer fuel prices for motor-transportation fuels under the 25 percent requirement, given different assumptions about fuel taxes and subsidies. The figure shows the range of prices that end users would see for conventional fuels and the alternatives, in gasoline-equivalent units. EIA's reference projection is $2.13 per gallon (in 2004 dollars).

Figure 3.5 shows both the potential costs of biofuels and the important effects that the pricing mechanisms can have on fuel prices. Under the subsidy mechanism, the price remains roughly equal to the EIA reference level, and there is very little variation in price, because any cost differences between gasoline and biofuels are paid by government subsidy.

In contrast, with the fossil-fuel tax mechanism, fuel prices increase to levels considerably greater than those under the other mechanisms. The prices shown in this case reflect the true opportunity cost of the renewable alternatives, since the fossil-fuel tax raises the price of conventional fuels to the level of the alternatives. The only moderating factors on prices are the induced reduction in total fuel demand and the induced reduction in the world price of crude oil. Thus, the results for the tax mechanism show that renewable- and conventional-

Figure 3.5
Range of Prices for Gasoline and Gasoline-Equivalent Biofuels



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fuel prices could rise to as much as $7.00 per gallon, almost three times the EIA reference projection, if there is only limited progress in expanding supplies of low-cost biofuels. If there is very substantial progress in biofuels, the price could be close to the EIA reference level; scenarios in between indicate a price increase on the order of $1.25–2.00 per gallon over the reference value.

The range of prices in the scenarios with the revenue-neutral tax-and-subsidy mechanism lies between the other two pricing mechanisms. Overall, Figure 3.5 shows that the relative change in prices is higher for this market than for electricity.

EIA's analysis of a 25x'25 policy projects a $68 billion increase in motor-vehicle transportation–fuel expenditures in 2025, which is shown in Figure 3.4. In its high–oil price scenario, the expenditure change falls to $43 billion, and, in the high-technology case, it is $35 billion. Again, EIA's reference-case results are in the lower end of our range of estimates. EIA uses a pricing mechanism similar to the revenue-neutral tax-and-subsidy mechanism used in our analysis. As Figure 3.4 shows, expenditure changes are lower with this mechanism than with the subsidy. In addition, the consumer expenditure effects are lower with this mechanism than with the fuel tax, leaving aside the recycling of the tax revenues back to consumers.

EIA's results fall roughly in the middle of our results for the revenue-neutral tax-and-subsidy mechanism. As already discussed, EIA allowed for much larger production of corn-based ethanol and ethanol imports from Brazil that hold down the direct energy market cost of the requirement, relative to the need for substantial reliance on cellulosic fuels in our analysis. These differences are especially important for the cases in which U.S.-based cellulosic ethanol or FT biomass fuels are expensive, which occurs in the high-cost cases in our analysis. Our analysis uses a very broad range of assumptions for biofuel production costs and biomass supply, because these are highly uncertain factors at this point. In our analysis, most of the biofuels produced to meet the 25 percent requirement come from technologies that are in a precommercial state. Because the 25 percent requirement would mean widespread deployment of these technologies, we allow for a large range in their future costs.

Overall, Figures 3.1 through 3.5 show a wide range of possible outcomes from the renewable-energy requirement. The current knowledge base is not sufficient to assess probabilistically the likelihoods of these outcomes. The results do indicate that *the 25 percent policy requirements can be met with limited impacts on consumer energy expenditures, if there is substantial concurrent progress in reducing the costs of biofuel and bioelectricity production; growing a large-scale, low-cost biomass supply; and producing wind power in more remote or lower-quality sites. However, there are significant expenditure impacts in meeting these requirements when technological progress is more limited.*

Policy Mechanisms for Implementing the Policy Requirements Have Important Effects on Consumer Behavior and Expenditures

Figures 3.3 through 3.5 indicate that the pricing mechanisms for motor vehicle–transportation fuels have important effects on expenditure changes and consumer behavior in the motor-fuel market. Under the subsidy mechanism, the government pays the cost difference between renewable and nonrenewable fuels. This shields consumers from any cost differences, and the market price of fuel does not reflect the costs of renewable fuels. Figures 3.4 and 3.5 show that fuel prices remain low or decline, which results in higher fuel consumption than the reference case. This mechanism exacerbates any large cost differences between renewable and nonrenewable fuels, because consumers do not moderate their consumption when biofuels are costly. In the fossil-fuel tax case, market prices reflect the cost of biofuels, and Figure 3.4 shows that consumers reduce their demand considerably when the cost differences are large. This moderates the demand for biofuels and the impacts on expenditures, but it also causes potentially significant decreases in well-being from reduced use of motor fuels.

As already noted, the fuel pricing policies also can have significant impacts on electricity expenditures. This linkage occurs through competition between the fuel and electricity sectors for biomass. The fuel subsidy policy encourages consumption and reduces the supply of availability of biomass for electricity, requiring greater reliance on higher-cost wind resources to meet the 25 percent renewable-electricity requirement. The opposite is the case with the fuel taxation policy.

We have also noted that, in our analysis, wholesale producers of renewable electricity are assumed to receive prices equal to the incremental costs of the marginal resources used respectively to meet peak-, base-, and shoulder-load demands.[7] This has the effect of raising average and marginal costs for electricity, thus increasing retail prices and inducing more conservation than would be the case if different renewable electricity supplies received only their respective marginal costs. The effect of this greater conservation in the electricity market is to lower demand for biomass and thus reduce the expenditure impact of requiring increased biofuels.

Most analyses of renewable-energy requirements do not consider this range of policy mechanisms. EIA's analysis used a mechanism similar to the revenue-neutral tax-and-subsidy policy. As shown in Figures 3.1 through 3.5, the policy implementation can yield significant differences with the same underlying assumptions about cost and market behavior.

Meeting 25 Percent Requirements with Relatively Low Expenditure Impacts Requires Significant Progress in Renewable Technologies

Both biomass feedstock costs and wind-power costs are important factors explaining the variation in expenditures and electricity consumption shown previously. The cases with low expenditure changes have substantial progress in wind technology such that even poorer-quality wind sites could be developed to provide electricity at relatively low costs. In the high–expenditure change cases, biomass feedstock is costly and uncompetitive with other renewable-electricity sources. This resulted in wind power being used to fulfill a majority of the demand for renewable electricity, requiring development of poor-quality wind sites. Even with progress in wind-technology costs, these sites and the electricity produced from them are expensive.

Another important factor is consumer responsiveness to electricity price changes. Under all of the scenarios, the renewable electricity developed at the 25 percent penetration level is more expensive than fossil-fuel sources. Electricity prices rise, and the consumer response moderates the impact on total energy expenditures. In the low–expenditure change scenarios, consumers are generally more able to reduce demand in response to increasing prices. In the high–expenditure change scenarios, consumers are less able to respond to higher prices.

As noted, the net effect on expenditures of the 25 percent renewables requirements reflects the higher cost of substituting renewable sources for fossil-fuel sources; the reductions in the

7 Shoulder-load demand represents the intermediate level of demand between peak and base loads.

market prices of coal (which reduce the cost of remaining coal-fired electricity production) and natural gas (which reduce electricity production costs and costs of gas end use), as a consequence of the decreases in demands for these primary fuels; and decreases in total electricity demand as a consequence of higher prices. The relative magnitudes of these components depend on all the different assumptions made about renewable-electricity costs, the demand elasticity for electricity, and the demand and supply elasticities in the coal and gas markets. We find that the total expenditure saving from the drops in coal and gas prices typically has a fairly limited impact on total electricity expenditures across our range of elasticity assumptions. More significant is the effect of the electricity demand elasticity.

Similar to the electricity market, we find that biomass feedstock costs and technological progress in producing biofuels are key factors explaining the variation in expenditure outcomes. In general, with significant progress in biofuel technology and producing biomass feedstock, the requirement imposes small impacts on consumer energy expenditures. When biomass is costly to convert into biofuels at the high capacity needed to meet a 25 percent renewable-energy requirement, the requirement becomes expensive.

Another important factor was consumer responsiveness to fuel price changes. Under all of the scenarios, the renewable fuels developed at the 25 percent penetration level are more expensive than fossil-fuel sources. Except with the fuel subsidy mechanism, fuel prices rise, and the consumer response moderates the impact on total energy expenditures. In the low–expenditure change scenarios, consumers were generally more able to reduce demand in response to increasing prices. In the high–expenditure change scenarios, consumers were less able to respond to higher prices. The fuel subsidy mechanism blocks these adjustments and exacerbates the overall expenditure impacts, even though consumers are shielded from a direct increase in fuel expenditures.

As noted, the net effects on expenditures of the 25 percent biofuel requirement reflect the higher cost for the alternative fuels; the reduction in the world price of crude oil from the resulting decrease in U.S. oil demand; the pricing mechanism used; and decreases in total fuel demand as a consequence of higher prices (in cases in which fuel prices are not maintained through government subsidies). The relative magnitudes of these components depend on all the different assumptions made about alternative-fuel costs, the demand elasticity for motor fuels, and the demand and supply elasticities in the oil market. We find generally that the total expenditure saving from the drop in the world oil price contributes a relatively small impact to mitigating fuel expenditures across our range of elasticity assumptions. More significant are the combined effects of the fuel demand elasticity and the pricing mechanism.

To obtain a more systematic understanding of the factors influencing the changes in expenditures, we applied a statistical method of scenario discovery on our collections of results with the lowest and highest 10 percent of expenditure change outcomes (see Chapter Two). This method does *not* establish cause-and-effect relationships. That is, we cannot say whether, if factors A, B, and C hold, then expenditures will be high (or low). Nor can we say that, if expenditures are low (or high), then factors X, Y, or Z must hold in the corresponding scenarios. What we can say with the scenario-discovery approach is that of all the scenarios with the highest (or lowest) 10 percent of expenditure impacts, certain characteristics tend to occur more often than others. We discuss first the results from the electricity market and then the motor vehicle–fuel market.

"Cheap Wind, Consumer Response Not Rigid" Characterize Many of the Outcomes with Lower Electricity Expenditure Change

The analysis found that a great many of the low–expenditure change results for electricity were characterized by relatively low-cost wind power across the range of assumptions we considered and that consumer response to price increases was above a minimum threshold with the range of those assumptions we considered. More precisely, the analysis identified that all of the following three key factors were observed in a great many of the lowest–10 percent expenditure change outcomes in the electricity market (outcomes with net expenditure change in the electricity market of less than $10.25 billion):

- Wind capital costs have fallen over time by at least 30 percent less than in EIA's projections.
- The escalation of wind cost in moving from higher-quality to low-quality sites is at least 16 percent less than in EIA's projection.
- Demand elasticity is at least 0.25 in absolute terms, compared with the lowest assumed absolute value of 0.2.

Under EIA's reference-cost assumptions, the levelized cost of electricity for wind power at high-quality sites is $0.058 per kWh, and the levelized cost after adding the capacity needed to meet the 25 percent requirement is approximately $0.12 per kWh. In the scenarios outlined previously, the costs of high-quality wind power were near $0.041 per kWh, and the costs of the marginal wind projects are no greater than $0.075 per kWh even after adding more than 80 GW of new wind capacity (U.S. total wind-power capacity stood at 16.8 GW in 2007, according to the American Wind Energy Association, so this figure is an almost fivefold increase over current capacity). To further put the figures in context, progress in wind-energy technology needs to approach current DOE program goals for future cost reduction, which are about 30 percent below the costs assumed by EIA for 2025. In addition to cheap, new wind power, the condition on the long-run price elasticity of demand rules out the possibility of such sluggish demand response that expenditure impacts were large even with relatively favorable conditions with respect to wind costs.

"Only Moderate Wind Progress, Higher-Cost Biomass, Somewhat Limited Consumer Response" Characterize Many Outcomes with Higher Electricity Expenditure Change

In the high–expenditure change cases, we found that high-cost biomass feedstock negated all but the most aggressive improvements in wind-power technology and that consumer price responsiveness was not sufficient to moderate the expenditure impacts. More precisely, all five of the following key factors were observed in a great many of the highest–10 percent expenditure change outcomes (outcomes with net expenditure change in the electricity market greater than $36 billion):

- The decline in capital costs for wind is no better than 21 percent below EIA's reference projection.
- Wind cost escalation at low-quality wind sites is, at most, 15 percent below EIA's projection.
- The consumer price elasticity is less than 0.47 in absolute terms, compared with the maximum value of 0.6.

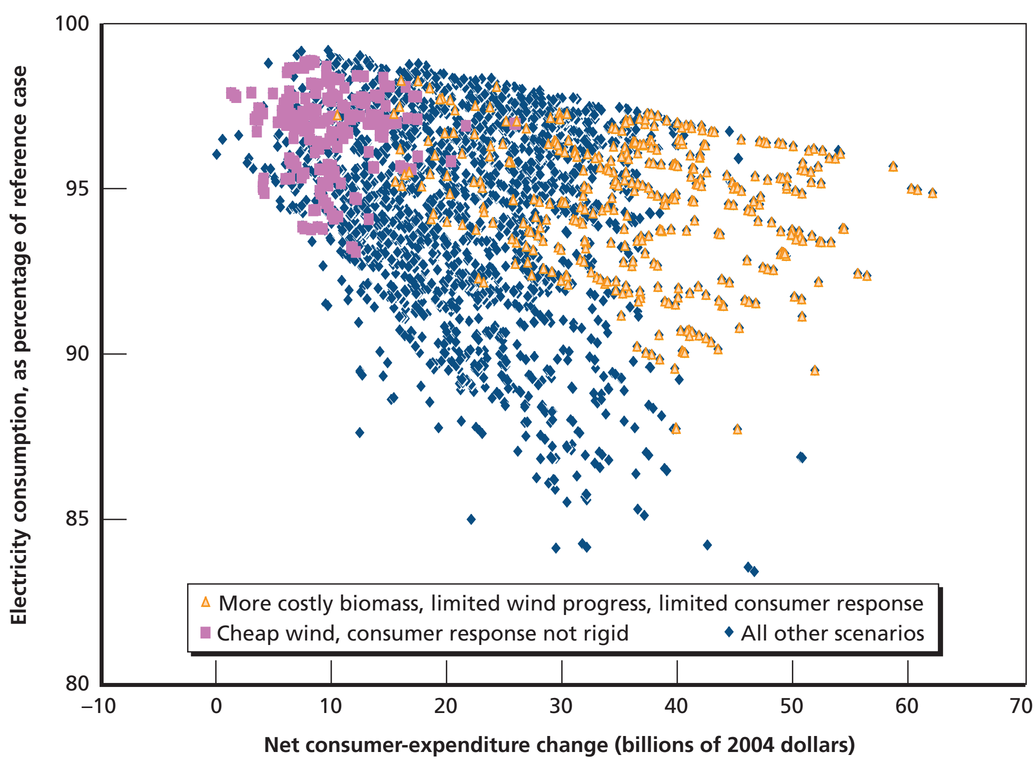
- Costs for backstop biomass exceed $117 per ton.
- The supply of biomass feedstock from waste and marginal lands is less than 950 million tons.

The last two factors relating to biomass imply higher costs for marginal supplies. In this case, wind power makes up much of the incremental renewable capacity added to meet the 25 percent requirement, which requires developing low-quality wind sites. Even with some progress in wind-power technology, electricity from these sites is expensive. Finally, the somewhat limited demand elasticity means that consumer expenditures are not diminished as much as they would be with a greater ability to adjust demand in response to higher prices.

The scatter plots in Figure 3.6 show the locations of the cases that satisfy the two sets of key factors described previously, so that they can be compared in terms of expenditure impacts to the entire range of results.

Figure 3.6 indicates that the sets of key factors described earlier do fairly well in terms of mapping to the cases in the lower and upper 10 percent of the expenditure range. However, the scenarios satisfying the two sets of key factors do also spill over into the scenarios with expenditures between the two extremes that we have considered, particularly the factors that tend to be associated with the high–expenditure change scenario. As well, some scenarios that satisfy neither set of key factors do, in fact, lie in the areas of lowest or highest 10 percent expenditure.

Figure 3.6
Electricity Consumption and Expenditure–Change Results with Low– and High–Expenditure Change Scenarios



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These observations emphasize how our scenario-discovery approach is a coarse filter that does not establish cause-and-effect linkages.

Overall, our analysis indicates that wind energy, biomass electricity, and biomass feedstock supplies all need to make substantial progress to achieve the 25 percent penetration level with limited impact on consumer expenditures. The factors associated with high–expenditure change scenarios suggest that, if future, low-cost biomass is not at the high end of current projects, backstop feedstocks are even somewhat more costly, and progress in wind-energy technology is not at the high end of the assumed range, high expenditure changes occur in many cases.

"Responsive Fuel Demand, Reasonably Cheap Biomass, and Significant Progress in Biofuel Technologies" Characterize a Great Many Outcomes with Low Motor-Fuel Expenditure Change

We conducted the same statistical analysis for each pricing mechanism in the motor vehicle–fuel market. A similar qualitative conclusion emerges across the cases, though with slightly different conditions for different pricing mechanisms. In this section, we summarize the results across the mechanisms and provide details in Appendix B.

Overall, the low–expenditure change cases tended to be associated with consumer demand that is very responsive to price increases within our range of assumptions, a relatively abundant amount of inexpensive biomass feedstock, and significant biofuel technology progress, so that production costs are low and yield is high. Specifically, we found that all of the following four key factors occurred in a great many of the low-expenditure cases:

- consumer price responsiveness in the most elastic portion of the assumed range (price elasticity greater than 0.65–0.7 in absolute value)
- a low-cost biomass feedstock supply from wastes and marginal lands exceeding 750–800 million tons per year
- biofuel yield from feedstock exceeding DOE program goals of 90 gallons of biofuel per ton of feedstock
- biofuel conversion costs less than $90–$100 per ton of feedstock.

The analysis found that consumer behavior was somewhat more important than the other three factors. This reflects the fact that, under the technology assumptions we make, price increases are generally greater in this market than in the electricity market. For the scenarios with the lowest 10 percent of expenditure impacts, on which we are focusing here, the combination of the three technology-related factors listed here helps hold down increases in biofuel costs to, at most, about $1.50–$1.75 more than gasoline and diesel in energy-equivalent terms (when produced in the quantity needed to meet the 25 percent requirement and assuming EIA's 2006 reference-case price of oil, $48 per barrel). The additional influence of a relatively high fuel demand response holds down price increases even further. For comparison, EIA's analysis of the 25x'25 policy estimates the incremental costs of more expensive biofuels at $2.18 per gallon.

"Less Responsive Fuel Demand, High Marginal Biomass Costs, and Limited Progress in Biofuel Technologies" Characterize a Great Many Outcomes with High Motor-Fuel Expenditure Change

In the high–expenditure change cases, we found the same set of key factors as in the preceding set but within ranges of parameter values leading to costly outcomes. The specific factors were

- relatively unresponsive fuel demand, with a price elasticity of less than 0.4 in absolute value
- costs of marginal, backstop biomass feedstock exceeding $150 per ton
- inexpensive biomass feedstock from wastes and marginal land of less than 750 million tons
- limited progress on biofuel conversion costs and yields.

Under this set of conditions, meeting biofuel demand at the 25 percent requirement level exhausts the inexpensive feedstock supply, even though that upper bound is well above the minimum level we consider. This requires use of more expensive backstop supplies, and, even with some technical progress in biofuel production, the resulting incremental costs of biofuels are high. Finally, high–expenditure change impacts are associated with consumers not reducing demand enough in response to higher fuel prices to lower the total expenditure changes.

The scatter plots in Figure 3.7 show the locations of the cases that satisfy the two sets of key factors described here so that they can be compared in terms of expenditure impacts to the entire range of results. We show results for all three of the fuel pricing policies. This means that each set of low-cost and high-cost scenarios must be considered relative to (geometrically, at the left and right ends of) the corresponding set of scenarios for each pricing policy.

Similar to the electricity market results, the two key factors described earlier tend to do fairly well in mapping to the lower– and higher–expenditure change cases for each pricing mechanism. However, there are, once again, some scenarios in the middle range of expenditures that also satisfy the key factors, and some scenarios satisfying the key factors that lie in the middle range of expenditures.

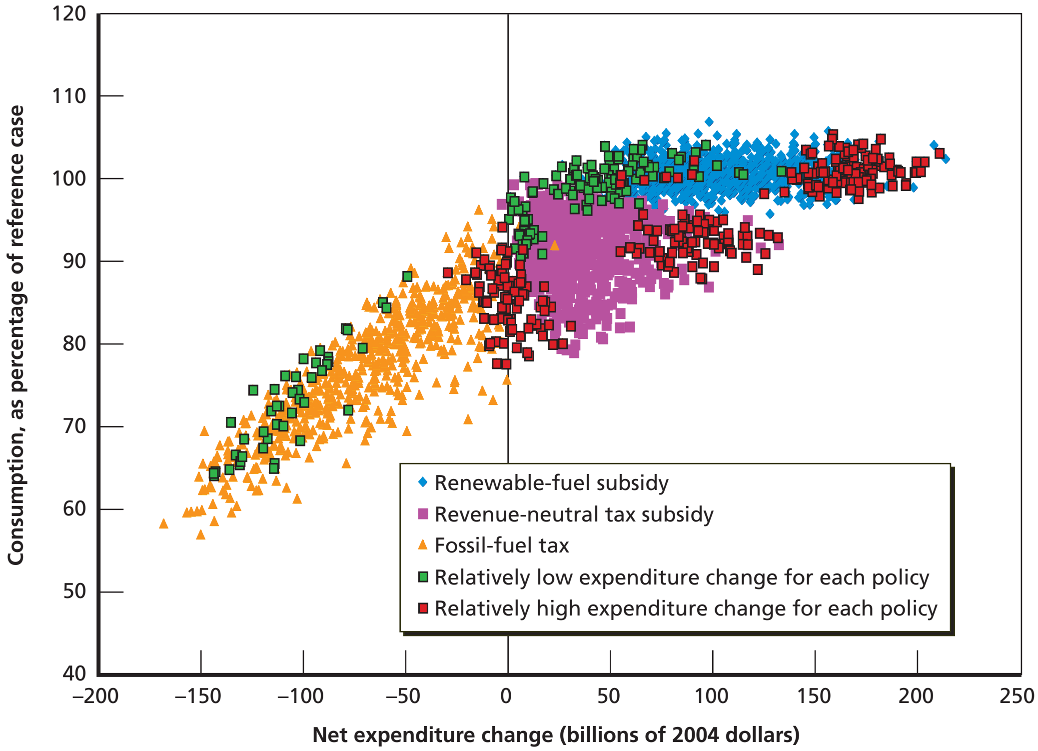
Potential Impacts of Biomass Scarcity Can Be Especially Significant

As noted, the cost and supply of future biomass feedstocks are highly uncertain factors but also among those factors with the greatest potential influence on expenditure impacts. Without a reasonably large and inexpensive feedstock supply, the 25 percent requirement can become expensive in terms of direct impacts on energy expenditures. These likely would include increases in land and food prices, as well as negative impacts on water supplies and water quality.

The 25 percent renewable-energy requirements for electricity and motor vehicle–transportation fuels would entail a massive expansion of biomass supplies beyond current levels of production. In just the motor-vehicle transportation–fuel market alone, production of biofuels would need to expand by more than 10 times from its current levels.[8] Under the combined renewable-energy requirements, biofuel refineries and power plants would compete

[8] According to AEO 2007, 2006 U.S. production of ethanol was 0.54 quads (1 quadrillion British thermal units [BTUs]). A 25 percent requirement for biofuels would require more than 7 quads of biofuels by 2025, using EIA projections of motor-vehicle demand for gasoline and diesel.

Figure 3.7
Motor-Fuel Consumption and Expenditure Change Results with Low– and High–Expenditure Change Scenarios



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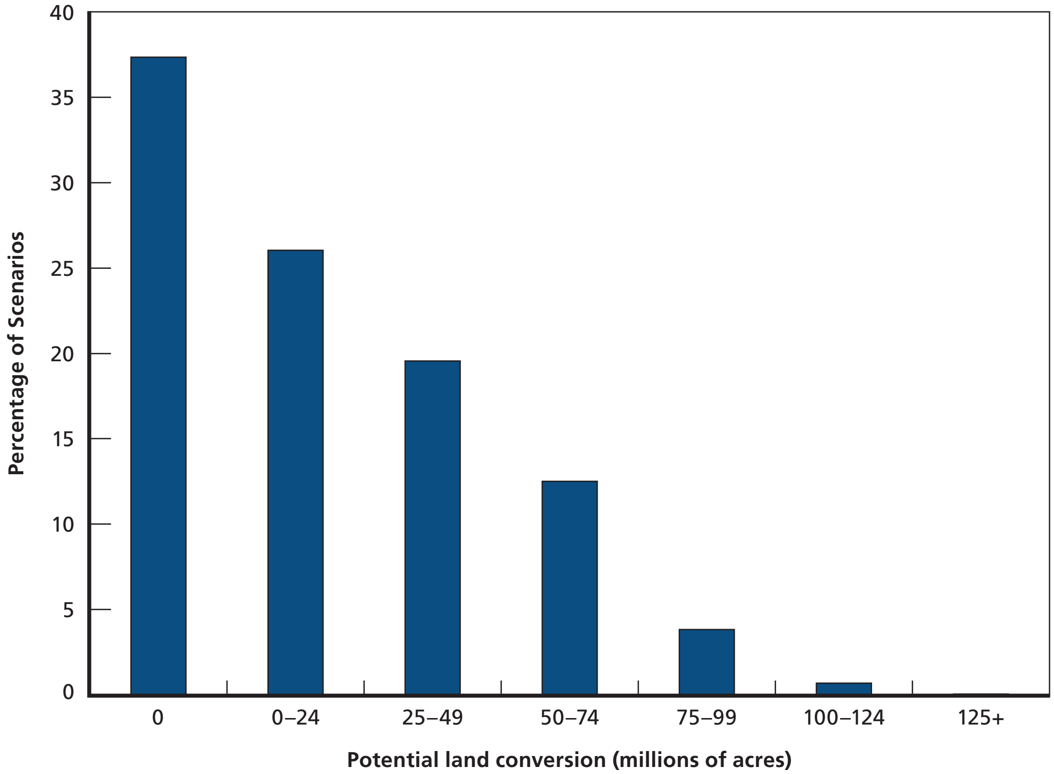
for biomass supplies to produce renewable energy, and the demand for biomass would far surpass the amount currently used for energy.

In our analysis, we found a common factor in the high–expenditure change scenarios for both markets was a limited supply of inexpensive biomass feedstock from wastes and marginal lands. The key determinants for this factor varied, and there is not a hard threshold value. However, the results tend to suggest more risk of high-expenditure impacts if available low-cost stocks are below 750 million tons of biomass per year, and less risk if supplies exceed this level (depending on several other issues, as discussed earlier). As noted, recent estimates by Oak Ridge National Laboratory used by EIA ranged from about 450 million to 500 million tons. Other estimates suggest that more than 1 billion tons of feedstock are available. Our analysis shows that, if inexpensive biomass feedstock supplies are not in the upper end of this range, then high–expenditure change outcomes can occur in many cases.

The potential for large-scale land conversion to satisfy biomass demand also is highly uncertain but could be significant. We calculated the amount of potential land conversion in each scenario that would be required to meet the demand for biomass, *if* the combined biomass demand from both markets exceeds the available supply from wastes and marginal lands and *if* the backstop supply were obtained entirely from domestic land conversion (versus biofuel imports). Figure 3.8 shows the range of results for this measure.

Figure 3.8 shows the percentage of scenarios falling into various land-conversion bins. Again, these results should *not* be interpreted as indicating probabilities, since we imposed no

Figure 3.8
Range of Potential Land-Use Conversion Needed to Meet Biomass Demand



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judgments on the relative likelihoods of different scenarios. Many scenarios implied no need for land-use conversion. We used scenario-discovery analysis on these scenarios to identify their common key factors. Our finding was that, in many scenarios without land conversion, the supply of biomass from waste and marginal lands exceeded 755 million tons—a figure larger than assumed by EIA but below the more optimistic Oak Ridge National Laboratory estimate discussed previously. There also were some scenarios with land-use conversion greater than 50 million acres.[9] Common features in many of the scenarios with more than 50 million acres of land conversion were relatively limited, low-cost biomass (less than 635 million tons) and relatively high fuel demand, because of the use of a fuel subsidy or tax-plus-subsidy pricing policy. Lower total fuel demand as a result of a fossil-fuel tax policy does not generate the same pressures on feedstock availability.

Estimating the effects of land-use change on land prices and food costs was beyond the scope of this study. Conceptually, an increased demand for agricultural land for biomass feedstock would cause land and food prices to increase. Recent experience with the impacts of growth in corn-based–ethanol production suggests that these price changes can occur quickly and reach across numerous sectors of the food industry, with potentially significant effects on consumer well-being.

[9] For reference, the USDA estimated that in 2002, total current agricultural land supply was slightly over 440 million acres. Pasture and rangeland accounted for 587 million additional acres (USDA, 2002).

Our findings also may understate the potential for agricultural-land conversion because we assume that the per-acre yield of biomass feedstock is a constant 5 tons per acre. This assumption might not be appropriate for land currently used for grazing. In fact, a strong demand for biomass for fuels and electricity could induce conversion of more prime land with higher yield (e.g., 9 tons per acre), even though this land also has a higher opportunity cost of conversion in terms of alternative agriculture crop value forgone. The degree to which this conversion would occur would depend not only on the balance of competing land-use values domestically but also on the price and availability of imported biofuels. A better understanding of these land-use economics is a high priority for further research in this area.

Policy Requirements Can Reduce CO_2 Emissions Significantly, but Incremental Energy Costs per Emission Reduction Vary Widely and May Be High

Figure 3.9 shows the CO_2 reductions from imposing the requirements in both the electricity and motor-fuel markets. Emission reductions from electricity are measured horizontally, while motor-fuel emission reductions are measured vertically. The figure shows that total CO_2 emission reductions from both sectors almost always exceed 1 billion tonnes,[10] which would represent 20 percent of the projected 2025 emissions in these sectors without the requirements. Total CO_2 reductions in the figure can range to more than 2 billion tonnes. For comparison, EIA's 2006 reference-case projection of total U.S. CO_2 emissions from energy production and consumption in 2025 is about 7.6 billion tonnes. Thus, 1 billion and 2 billion tonnes represent, respectively, about 13 percent and 26 percent of total projected national emissions.

The CO_2 reductions shown in Figure 3.9 include the effects of substituting renewable energy for fossil fuels and reductions in energy demand from higher prices.[11] Note that the figure shows a concentration of scenarios with CO_2 reductions in the motor vehicle–fuel market centered on 500 million tonnes. These are the scenarios with subsidies for renewable transportation fuels. In these scenarios, fuel prices do not rise, and the CO_2 reductions in the sector are a pure fuel-substitution effect.

We also calculated the incremental energy supply costs per CO_2 reduction for each scenario. This measure calculates the cost difference between renewable and fossil energy for the last unit of renewable energy supplied to meet the 25 percent requirement (marginal resource) divided by the difference in GHG emissions. While this is a cost measure rather than an expenditure measure, it is still not a full measure of the economic cost of the CO_2 limitations, since it does not incorporate all the losses in economic benefit that result from reduced energy use.

Figure 3.10 shows these results. It shows that, like expenditure changes, the incremental costs vary considerably across the cases and are generally greater in the motor vehicle–fuel market. The incremental cost per unit of emission reduction ranges are \$30–\$157 per tonne of CO_2 in the electricity market and \$22–\$387 per tonne of CO_2 in the motor vehicle–fuel market.

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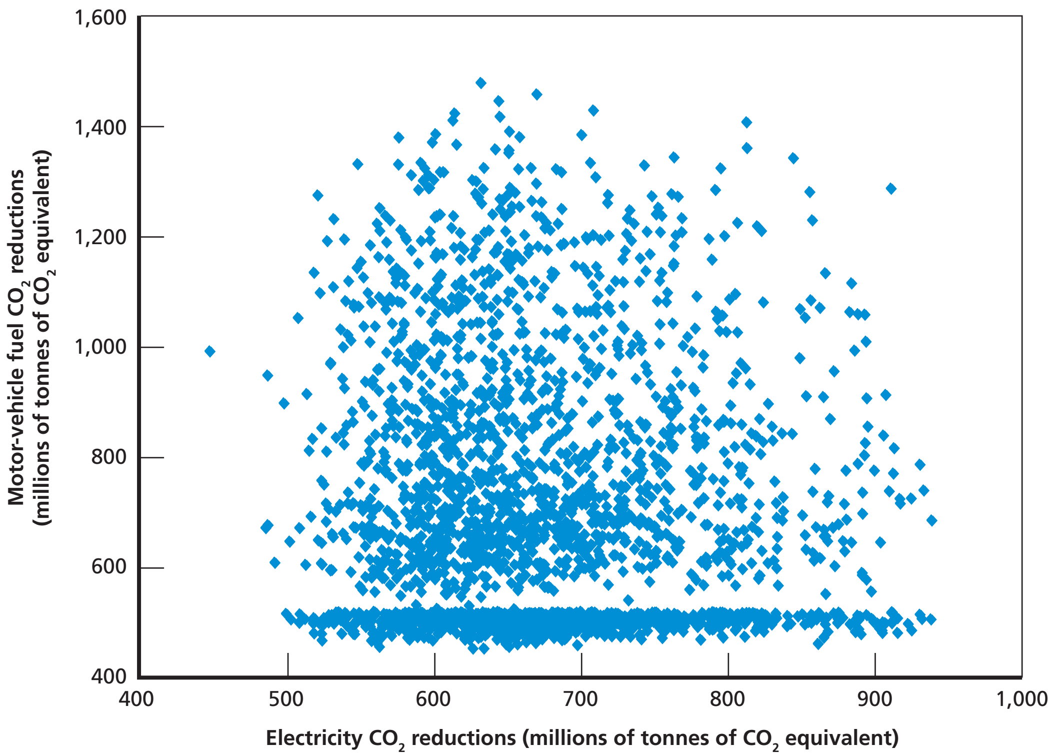
[10] In our analyses of biomass, we relied on figures in British tons. CO_2 emission rates tend to be quoted in metric tons, or tonnes, so we change over to that unit of measurement here.

[11] We note again that our figures for the relative CO_2 intensity of the different fuels across the cycle of production and consumption do not include the possibility of significant temporary releases of stored soil carbon from expanded cultivation.

Figure 3.9
CO_2 Reductions in Both Markets



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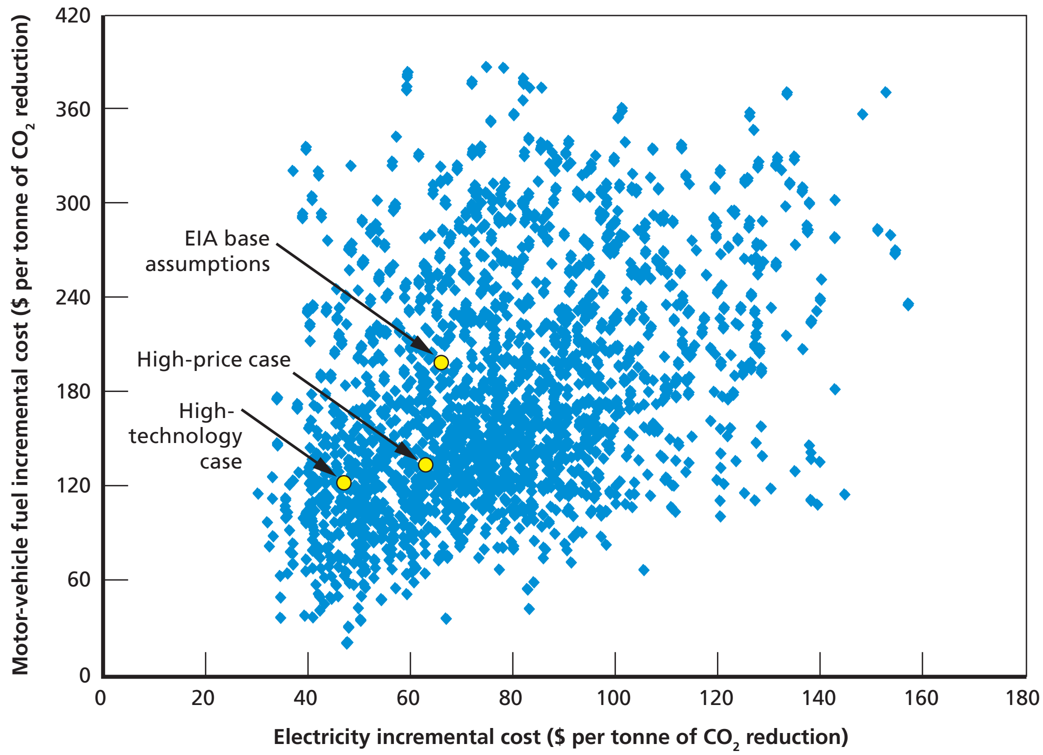
We can compare these figures with calculations of incremental costs from the EIA analysis of a 25x'25 policy. Under EIA's base-level assumptions, the figures are \$66 and \$198 per tonne of CO_2 for electricity and biofuels, respectively. Under their high–petroleum-price case, both figures decrease to \$63 and \$133 per tonne of CO_2 for electricity and biofuels, respectively, and, with their high-technology case, they decrease further to \$47 and \$122 per tonne of CO_2 for electricity and biofuels, respectively.

Comparison of our figures or those from EIA with other estimates of the cost per unit of CO_2 mitigation is complicated for several reasons. Mitigation costs depend on the time frame under consideration (near term or longer term), the degree of total emission reduction under consideration, the type of policy instruments being utilized (more-flexible instruments generally are more cost-effective), and the assumptions made about the degree of preexisting distortion in energy markets (in particular, how much low-cost energy-efficiency investment is feasible). In addition, approaches differ in the nature of the metric used to measure cost: Results from an economic model of economywide emission trading may not compare with simpler measures of energy cost, as we have calculated here.

With those caveats in mind, we can nonetheless offer some points of comparison between our figures and several other measures found in the literature. A recent MIT study of the long-term future use of coal in the power sector concluded that, in the longer term, the incremental cost of carbon capture and sequestration (CCS) ranged from \$30 to \$40 per tonne of CO_2 for pulverized coal plants and near \$20 per tonne for CO_2 for newly built IGCC plants (MIT, 2007). Another recent study by the McKinsey Global Institute (Creyts et al., 2007) argued

Figure 3.10
Range of Incremental CO_2 Reduction Costs in Electricity and Fuel Markets



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that there were a number of CO_2 mitigation options available at a cost below $30 per tonne of CO_2, mostly involving energy efficiency. The focus in the McKinsey analysis was more on incremental and near-term ("low-hanging fruit") reductions, so these figures may be low relative to those appropriate for considering more significant emission reductions over the longer term.

Finally, a recent review of findings from a number of energy-economy models used to simulate a national emission trading program reported estimates of CO_2 emission permit prices in 2030 from $15 per tonne to $100 per tonne, depending on the stringency of the national emission target being imposed (Aldy, 2007). However, a 25 percent reduction from business as usual implies a permit price of more like $30 per tonne, while $100 per tonne reflects a much more stringent emission reduction—more than 50 percent (Aldy, 2007, pp. 63–64, figures 9, 10).

Other studies of CO_2 mitigation and sequestration costs also involve considerable uncertainties. In particular, CCS also involves technologies that are not commercially available today. Moreover, as noted, the relatively low cost of improving energy efficiency from current levels certainly does not imply such a low incremental cost at a level of CO_2 reduction that the 25 percent renewables requirements might suggest. A more complete comparison would account for these and other uncertainties. Our results do suggest, however, that renewable-energy requirements at the 25 percent level–especially for transportation fuels–may have higher incremental costs for CO_2 reductions than the costs of CO_2 reduction from broader, economywide policies or of efforts focused on energy efficiency. Further research is needed to explore the cost trade-offs among these various mitigation options.

Lower-Level Renewables Requirements Reduce Expenditure Changes

Figures 2.1 and 2.3 in Chapter Two show that the cost of renewable energy increases as the amount of capacity added to the system rises. This relationship occurs because the highest-quality, most accessible sites are developed first and the more marginal resources are used afterward. Therefore, for a given set of cost assumptions, lower-level requirements will always cost less than higher levels. When renewable-energy costs increase rapidly as less productive capacity is added, the expenditure change differences among 15 percent, 20 percent, and 25 percent requirements can be significant. Figure 3.11 shows that expenditure changes can escalate rapidly at higher requirement levels.

In Figure 3.11, we show results for one particular set of assumptions at the 15 percent, 20 percent, and 25 percent renewable-energy requirement levels. To generate these results, we selected parameter values in the middle of our ranges of assumptions to illustrate the effects of changing the requirement level for renewables. These results do not imply that midpoint parameter values are a base or most likely set of assumptions. We have also used the revenue-neutral tax-and-subsidy pricing mechanism in generating these illustrative results.

Figure 3.11
Example of Expenditure Changes at Increasing Renewables Requirement Levels

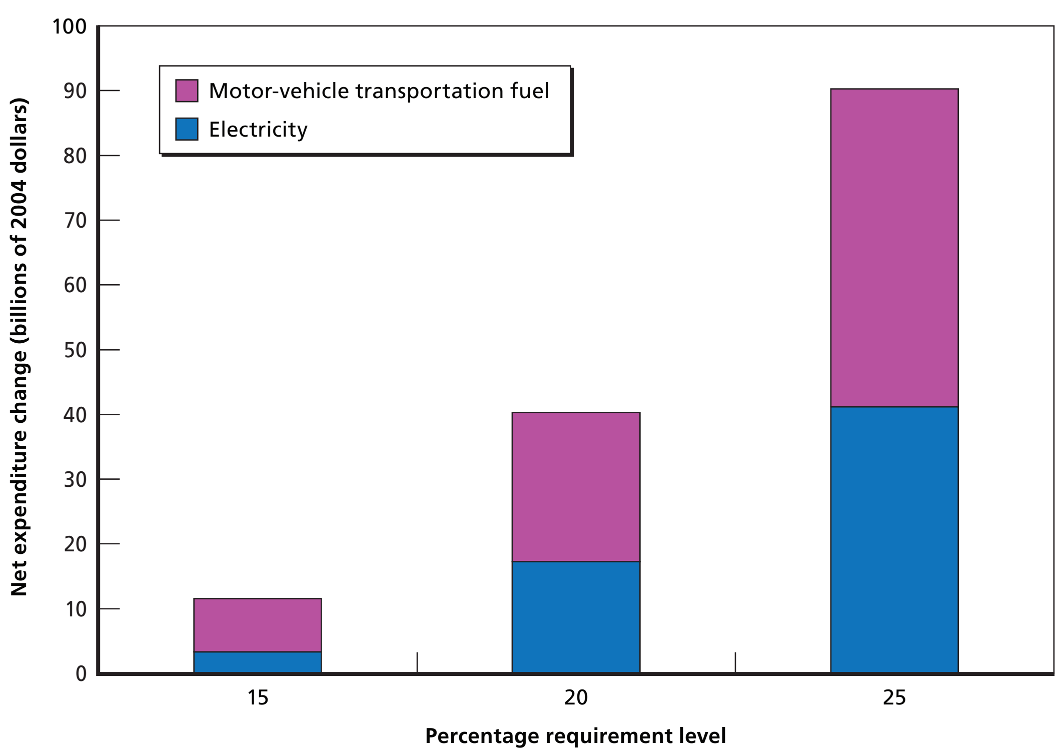

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Figure 3.11 shows two key features that are consistent through most of the results. Expenditure changes grow as the requirement increases and tend to jump sharply between 20 percent and 25 percent. In addition, expenditure changes in the motor vehicle–fuel market are generally higher than those in the electricity market, both as an absolute value and as a percentage of EIA's reference case.

The jump in expenditures between the 20 percent and 25 percent requirement levels occurs for two reasons. Since the marginal costs of renewable energy increase at higher utilization levels for capacity, higher requirements in general lead to increasing expenditures. The sharp increase in this case occurs because demand for biomass to produce biofuels increases the price of biomass feedstock. With higher-priced biomass feedstock, biomass-derived electricity is uncompetitive with other electricity sources, and the remaining requirement for renewable electricity is met through mostly wind and some geothermal electricity, which both have increasing costs as more capacity is developed.

We also assess the incremental costs per unit reduction in CO_2 for the different requirement levels. Table 3.1 summarizes these findings.

Again, we ran these results setting our parameter assumptions in the middle of our assumed ranges and using the revenue-neutral tax-and-subsidy pricing mechanism. We show these results to illustrate the increasing costs that occur at higher requirement levels and not as a representative or most likely scenario. Table 3.1 shows that expenditures per CO_2 reduction increase as the renewables-requirement level increases.

Energy Security and Energy Prices

Since the oil price shocks of the 1970s, there has been persistent concern about the adverse consequences for the economy of both high and unstable oil prices. The concern about high oil prices reflects not just the resulting burdens on individual energy users. It also reflects the prospect of an excess transfer of national wealth to foreign oil producers (in particular, members of OPEC) that are widely seen to hold prices above competitive market levels by restricting output. Oil prices elevated artificially above competitive levels provide a rationale for policy intervention. As a very large economy and consumer of many goods, the United States could intervene in many markets in an effort to alter prices to its advantage, but it usually eschews policies to exercise this market power out of a belief that this would gravely harm free trade. This argument does not automatically apply in the case of pricing oil above competitive market

Table 3.1
Example of How Incremental Costs per Unit of CO_2 Reduction Vary at Different Renewables Requirement Levels

	Incremental Cost per Tonne of CO_2 Equivalent Reduced (2004 dollars)	
Requirement Level (%)	Electricity	Motor-Vehicle Fuel
15	31	83
20	80	153
25	122	224

levels, although it remains necessary to examine empirically what a concerted effort by the United States to drive down prices might accomplish.

Alternative transportation fuels (biomass- or unconventional fossil-based) can diversify global supply and lower the market price of oil through increased competition. This can improve long-term energy security by cutting the excess transfer of national wealth to petroleum producers.[12] Even a small oil price reduction, accruing to consumers over a large volume of oil consumption and imports, can add up to a significant financial benefit, as our results have indicated. However, the magnitude of the benefit will depend on the cost-effectiveness of the alternative fuels and the response of oil producers. For example, if they reduce long-term output to maintain a constant market share and thus buffer the decline in oil prices (Gately, 2007), the import cost savings would be weakened as well. As discussed already, we use different world oil supply elasticities to very roughly capture the different effects on oil prices of renewable-fuel substitution in the United States.

Oil price spikes are a concern because of the potential for adverse effects on national employment and output. While, in principle, individual consumers can factor the risk of future oil price instability into their own energy consumption and investment decisions, the macroeconomic effects are not likely to be fully internalized in individual energy consumption decisions. Having alternative transportation fuels could reduce the volatility of oil prices, but, in practice, this benefit is likely to be quite small unless the share of unconventional fuels is so large relative to total demand that the alternative fuel suppliers (not petroleum suppliers) are setting market prices. With a smaller market share, the prices of the substitutes will be highly correlated with prices for conventional petroleum in competitive wholesale and retail product markets.

What Happens If Future Oil Prices Are Well Above Reference Levels?

So far, all of our analysis has been premised on EIA's 2006 reference-case assumptions and projections for 2025. In focusing on this standardized set of assumptions, we do not want to give short shrift to the situations that could arise if oil prices remained at a much higher level for the next 20 years than they do in that reference case. We already have noted from EIA's 25x'25 analysis that expenditure change impacts are lower with higher-than–reference-case oil price assumptions. This reflects that the high–energy-price base case already has more energy conservation and somewhat more renewable-energy use, so less of an additional impact on energy expenditures must be made to achieve the 25 percent requirements.

Our project scope did not allow us to construct an entirely new library of baseline parameters and NEMS responses in terms of capital investment and other factors that we could use to implement a full-blown study of an alternative baseline scenario. However, we can carry out a comparison of our fuel-sector results by adjusting the oil-market supply curve to simulate EIA's high–oil price case. In this comparison, we set all technology parameters to the illustrative values assumed earlier in looking at alternative renewables requirements, and then we estimate expenditure changes when the world oil price is \$85 per barrel rather than our reference-case assumption of \$48 per barrel. Table 3.2 shows these results.

These results are consistent with EIA's. When the reference oil price is higher, the additional expenditures for implementing the renewables requirements are lower in absolute and relative terms. The latter finding reflects higher reference-case energy expenditures with the higher reference-case oil price. If prices were expected to stay well above our assumed reference

[12] Policies to reduce fuel demand through improved energy efficiency also can yield this benefit.

Table 3.2
Potential Impacts on Increased Fuel Expenditures with Higher Base-Case Oil Price

EIA Scenario	Oil Price ($/barrel)	Motor-Fuel Expenditure Change ($ billions)	Change from Initial (%)
Reference	48	49	10
High oil price	85	23	4

level consistently for the next 20 years, the energy market would undertake more conservation and energy efficiency, as well as more substitution of renewable alternatives. Under these conditions, the additional energy-expenditure burden under the renewables requirements would be smaller; at the same time, the need for a policy requiring increased renewables also would be less urgent, given the price signals facing the economy. On the other hand, such consistently high oil prices could make a number of unconventional fossil-energy sources economical, notably oil shale, expanded oil sands, and FT fuels from coal. These fuels could well be more competitive than the renewables we have considered for 2025, which would increase baseline CO_2 emissions in the absence of stricter new GHG limits.

CHAPTER FOUR

Concluding Remarks

While the broad objective of significantly increasing renewable-energy use in motor fuels and electricity appears to be technically achievable, our findings indicate that the resulting impact on consumer energy expenditures is quite uncertain. The wide range of potential expenditure impacts reflects several significant uncertainties with respect to the future availability and cost of renewable energy sources.

Holding expenditure impacts to a modest level requires a number of concurrent significant advances in renewable-energy technologies. Of these, advances in low-cost biomass feedstock provision and improvements in the economic efficiency of conversion rank at the top of the list. While further improvements in wind technology also are very important, as is improved energy efficiency, biomass plays a central role in expanding both renewable electricity and renewable fuels.

Given this finding, *a large, inexpensive, and easily converted biomass supply is necessary for significantly increased renewable-energy use to have relatively low impact on consumer energy expenditures. The significant resulting increase in biomass usage would require harvesting various energy crops at a scale that vastly exceeds current practice. Without significant advances in biomass production from marginal lands, greatly increased biomass production could be accompanied by adverse environmental and economic impacts due to land conversion*. There is also the possibility that land-use changes engendered by higher reliance on biomass could result in a temporary increase in GHG emissions. *Technical advances in the provision of economically and environmentally sound feedstock should be a top priority for R&D programs focused on increasing biomass-based energy supplies*.

A renewable-fuel requirement reduces demand for petroleum and lowers the international price of crude oil. This oil price impact from fuel diversification can be seen as enhancing energy security through increased competition with petroleum-exporting countries in a position to exercise market power. While this is a clear economic benefit from increased use of renewables, in itself, it is not likely to be the most cost-effective option, since improvements in energy efficiency and development of other substitute sources also can exert downward pressure on oil prices. Moreover, energy security depends on how vulnerable an economy is to oil price shocks as well as on the level of oil prices. Substitution of relatively costly renewable fuels for fossil-based alternatives at a 25 percent level may do relatively little to mitigate the risk of oil price shocks. In competitive wholesale and retail markets for fuel, the prices of the alternatives will be highly correlated with the price of oil-based petroleum products.

Our analysis also indicated that increasing to 25 percent the share of renewables can significantly reduce CO_2 emissions. However, the incremental increase in energy cost per unit of CO_2 reduction varies widely depending on circumstances, reaching very high levels unless there is very substantial cost-reducing innovation in expanding renewables. Fossil-fuel prices that are higher than the baseline levels assumed in this analysis would induce greater use of renewable energy and thus reduce the incremental cost of achieving 25 percent renewable energy (thereby also lessening the need for setting this as a policy target). High fossil-fuel prices also improve the economics of other alternatives that can reduce GHG emissions and improve energy security, such as energy efficiency and unconventional energy sources.

Given this finding, *increased renewables use can reduce CO_2 emissions and can enhance energy security by reducing petroleum use and increasing international competition with crude-exporting countries. However, these gains likely could be realized more cost-effectively through a diverse portfolio of energy measures that improve energy efficiency, reduce CO_2 emissions, and increase the availability of energy sources other than conventional petroleum. Moreover, while the pricing of renewable fuels can be used to insulate consumers from price changes, this approach adversely affects energy efficiency and the development of other alternatives as well as increasing pressure on the federal budget to subsidize higher-cost fuels.*

Other elements of such a portfolio already have been the subject of considerable analysis and debate: higher energy-efficiency standards, in particular for vehicles; introduction of alternative fossil-based fuels and electricity production, if adequate measures for sequestering CO_2 in the production of the energy can be implemented; energy taxes to reduce either petroleum consumption (for energy security) or all fossil fuels (to reduce CO_2); and CO_2 cap-and-trade programs. Each of these types of measures has pros and cons both economically and politically.

Requirements for renewable-energy use could be a part of the portfolio, and they already are being developed by a number of states for use in the electricity sector. They could be justified conceptually as a way to reduce initial investment barriers by stimulating greater private-sector R&D and learning through doing and as an alternative to price-based policy instruments if those are handicapped by political constraints. Our findings suggest that renewables requirements on the order of 25 percent could be met with modest impacts on consumer energy expenditures if there is substantial progress in several key renewable-energy technologies and biomass feedstock production. However, if significant technological advances do not occur in these areas, then the policy could become quite costly. Moreover, our analysis provides only a snapshot of annual expenditures in 2025 and does not deal with the higher outlays in intermediate years of the transition, when substantial new capital would have to be invested and technologies are still relatively underdeveloped. These observations suggest that any requirements for increased use of renewables not only should be part of a larger policy portfolio, but also should be phased in gradually and carefully reviewed periodically to assess how technology is advancing before requirements are raised further.

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