DOE/EIA-0607(98)
Distribution Category UC-950

Issues in Midterm Analysis and Forecasting 1998

July 1998

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

Preface

Issues in Midterm Analysis and Forecasting 1998 (*Issues*) presents a series of nine papers covering topics in analysis and modeling that underlie the *Annual Energy Outlook 1998* (*AEO98*), as well as other significant issues in midterm energy markets. *AEO98*, DOE/EIA-0383(98), published in December 1997, presents national forecasts of energy production, demand, imports, and prices through the year 2020 for five cases—a reference case and four additional cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. The forecasts were prepared by the Energy Information Administration (EIA), using EIA's National Energy Modeling System (NEMS).

The papers included in *Issues* describe underlying analyses for the projections in *AEO98* and the forthcoming *Annual Energy Outlook 1999* and for other products of EIA's Office of Integrated Analysis and Forecasting. Their purpose is to provide public access to analytical work done in preparation for the midterm projections and other unpublished analyses. Specific topics were chosen for their relevance to current energy issues or to highlight modeling activities in NEMS.

The *AEO98* projections are used by Federal, State, and local governments, trade associations, and other planners and decisionmakers in the public and private sectors. They are published in accordance with Section 205(c) of the Department of Energy Organization Act of 1977 (Public Law 95-91), which requires the Administrator of EIA to prepare an annual report that contains trends and projections of energy consumption and supply.

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Issues will be available on the August release of the EIA CD-ROM and on the EIA Home Page on the Internet (*http://www.eia.doe.gov*) by mid-July 1998. *AEO98*, the assumptions underlying the *AEO98* projections, and tables of regional and other detailed results from the *AEO98* forecasts are also available on the CD-ROM and on the EIA Home Page. *The National Energy Modeling System: An Overview 1998*, DOE/EIA-0581(98), which provides a summary description of NEMS, and complete model documentation reports for NEMS are available on the CD-ROM and on the EIA Home Page.

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Competitive Electricity Prices: An Update[1]

by
J. Alan Beamon

Throughout the country, States are moving to make their electricity generation markets more competitive. Although the timing will surely vary, most States plan to implement significant changes in the pricing of electricity between now and the first few years of the 21st century. By estimating competitive generation prices based on marginal costs, this paper illustrates that the range of generation prices across the regions of the country can be expected to narrow with competition. However, it also shows that substantial differences in total electricity prices among regions will remain, because of differences in resource availability, the costs of nongeneration (transmission and distribution) services, climate, and taxes.

Background

Historically, electricity prices in the United States have not been set by market forces. Consumers' electricity supply choices have been limited to the utilities franchised to serve their areas. Similarly, electricity suppliers have not been free to pursue customers outside their designated service territories. Utilities have built generation, transmission, and distribution capacity only to serve the needs of the customers in their service territories, and the price of electricity has been set administratively, based on the average cost of producing and delivering power to customers.

The regulatory structure of the U.S. electric power industry evolved from the belief that the supply of electricity was a natural monopoly, and that one supplier could provide services at the lowest cost. For a variety of reasons, both economic and technological, that view has changed. Today, the relationship between consumers and suppliers of electricity is poised for change.[2] Most States plan to implement significant changes in the procurement and pricing of electricity between now and the first few years of the 21st century. Thus, in the near future, some of the services currently provided by local utilities will be available from other suppliers.

The electricity business is made up of three major functional service components or sectors: generation, transmission, and distribution. The generation sector is the production arm of the business—the power plants where electricity is produced. The transmission sector can be thought of as the interstate highway system of the business—the large, high-voltage power lines that deliver electricity from power plants to local areas. The distribution sector can be thought of as the local delivery system—the relatively low-voltage power lines that bring power to homes and businesses. While it is expected that most consumers will continue to purchase distribution services from their local utilities and buy transmission services from a centralized pool, generation services are expected to be available from many sources.

For the most part, the prices for transmission and distribution services are expected to continue to be set administratively on the basis of the average cost of service. Some alternative approaches for pricing transmission services are being considered. In contrast, competitive market forces will set generation prices. Buyers and sellers of power will work together, through power pools or one-on-one negotiations, to set the price of electricity. As in all competitive markets, the supplier in the market[3] who has the highest costs will determine the price at any level of demand. During most time periods, the generation price of electricity will be set by the operating costs of the most expensive (in terms of operating costs) generating unit needed to meet demand, or what in economics is referred to as the "marginal cost" of production. When consumers' demand for electricity rises (for example, on a hot summer day), the generation price will rise as units with higher operating costs are brought on line. Conversely, on cool spring weekends when air conditioning is not needed and many businesses are closed, prices will be relatively low.

[1]This paper updates the work prepared in *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, DOE/EIA-0614 (Washington, DC, August 1997). This paper is based on work prepared for the *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

[2]For a discussion of the changing structure of the electricity industry, see L.S. Hyman, *America's Electric Utilities: Past, Present and Future* (Arlington, VA: Public Utilities Reports, Inc., 1994), and Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996).

[3]A supplier who is in the market is one who is able to find customers at the prices it is offering. During a low demand period there could be many suppliers who are unable to sell any output and, therefore, will have no impact on the price.

The movement toward competitive pricing of generation has several implications. Generation prices are likely to become more volatile, changing as consumers' needs move up and down across seasons and from hour to hour during the day. For example, as the temperature rises on a hot summer day, the use of air conditioning will increase, and the price of electricity will rise as plants with higher operating costs are used to meet demand. Competitive prices based on marginal costs will also be more sensitive to any factors that affect the operating costs of the marginal generators. For example, if the cost of fuel to marginal generators rises unexpectedly, the impact on prices will be readily apparent. With traditional cost-of-service pricing, these impacts are muted, because the costs for all plants are averaged together.

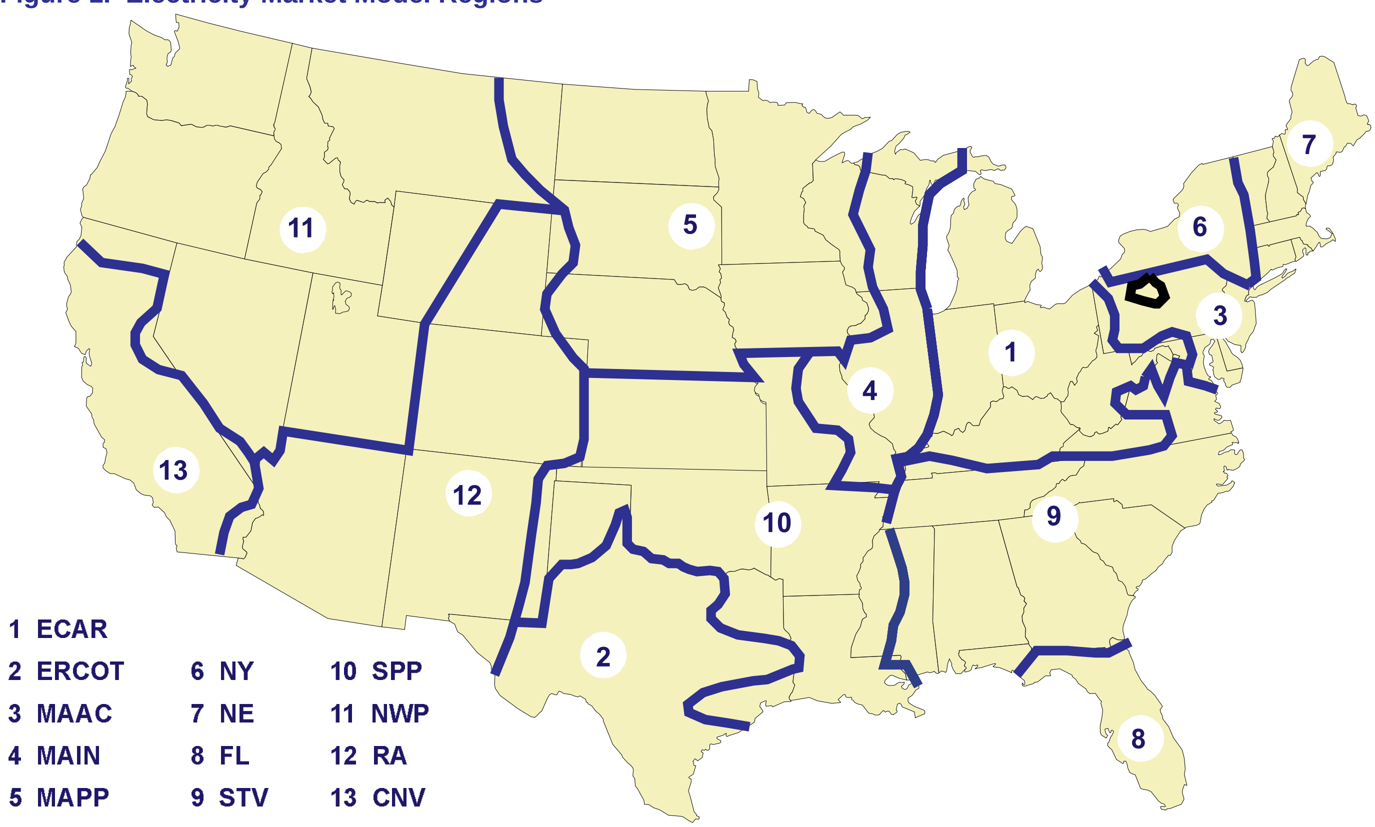
Both of the above characteristics of competitive prices were illustrated by national-level model results in the *Annual Energy Outlook 1998* (*AEO98*).[4] This report illustrates a third impact of the move to competitive generation pricing—the narrowing of the range of prices across regions of the country. Concentrating on the period 2005 to 2020 (after competition has been phased in), electricity prices are presented regionally for the generation component, the combined transmission and distribution component, and generation sector taxes.

Methodology

To simulate the transition to competitive electricity generation prices, prices based on average costs (cost-of-service pricing) and on marginal costs (competitive pricing) were calculated for each of 13 U.S. electricity supply regions (Figure 1) for the period 1998 through 2008.[5] An average price for each of the transition years was estimated using a weighted average of the two prices. Initially, in 1998, a 0.90 weight was given to the cost-of-service price, and a 0.10 weight was given to the competitive price. The weights were shifted over time, so that by 2008 the competitive price received a 1.0 weight and the cost-of-service price was no longer used. Transmission and distribution system prices were calculated from average costs throughout the projection period.

The gradual shift toward the competitive generation price was meant to reflect the path being taken by the States. Some States, such as California, are allowing consumers to choose their electricity suppliers (generators) as early as 1998. However, they are also allowing utilities to recover the costs of investments that were made to serve these customers over a certain number of years. Thus, the impacts of unfettered competition in the generation market will not be seen for a few years. In addition, even if consumers are free to choose their suppliers

Figure 1. Electricity Market Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[4]See Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), "Electricity Pricing in a Competitive Environment," pp. 20-23.

[5]The Electricity Market Model (EMM) submodule of the National Energy Modeling System (NEMS) represents the supply and demand for electricity in 13 regions based on the regions and selected subregions of the North American Electric Reliability Council (NERC).

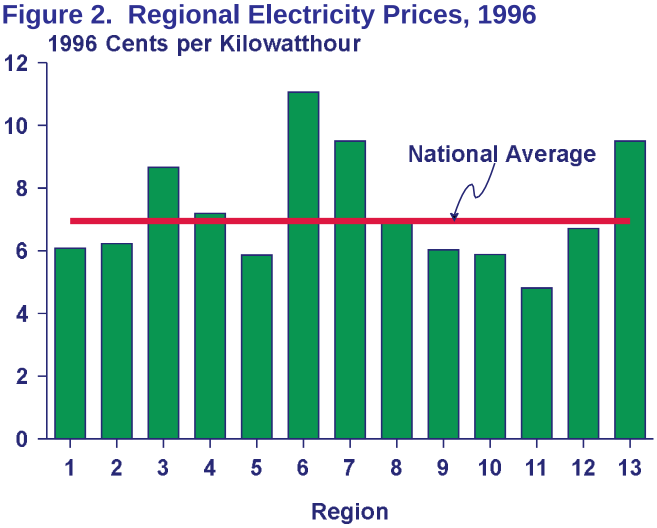
in the next few years, it could take several more years for the new market institutions needed to support competition to evolve fully.

Regional Competitive Electricity Prices

In today's market, average electricity prices vary substantially among different regions of the country (Figure 2). Prices in the highest cost region are nearly 2.3 times (230 percent) the prices in the lowest cost region. Many factors—such as differences in regional fuel availability and prices, labor and construction costs, climate, taxes, and customer mix (residential, commercial, and industrial)—contribute to the differences. For example, access to economical hydroelectric power is a major factor in the relatively low electricity prices seen in the Northwest. Conversely, the lack of low-cost hydroelectric or coal-fired power plants in the New York and New England regions is one factor in their relatively high prices. Still, the range in regional electricity prices is considerably larger than that seen for other energy products. For example, excluding Alaska and Hawaii, average gasoline prices in November 1997 differed by only 39 percent across the States. Similarly, fuel oil prices (excluding taxes) differed by only 29 percent across the States in November 1997.[6] Even when taxes are added, gasoline prices across the continental United States differ by only 54 percent.

In competitive markets, large regional price differences for a product would be expected to attract the attention of both suppliers and consumers. With the opportunity to make greater profits, low-cost suppliers would want to enter high-price markets. Similarly, consumers—especially those who use large quantities of the product—would move into regions with low prices and out of regions with high prices. Over time, these forces would tend to narrow the price differences between regions. Absent large transportation and local market costs, which in this analysis are assumed not to be affected by competitive pressure, the "price gap" should be quite narrow in the long run.

Figure 2. Regional Electricity Prices, 1996



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

The market forces described above are expected to affect regional electricity prices, especially those for generation services, as competition takes hold. By 2005, the range in the total price of electricity across regions is expected to fall to 4.2 cents, much lower than the 6.3-cent range seen in 1996 (Figure 3). Excluding the New York and New England regions, which have very high non-generation sector prices, the range is much narrower, at just over 2 cents per kilowatthour by 2020. The nearly 100-percent regional price gap is still much larger than that seen for gasoline and fuel oil. However, as mentioned for New York and New England, the competitive generation sector is not the source of most of the remaining gap.

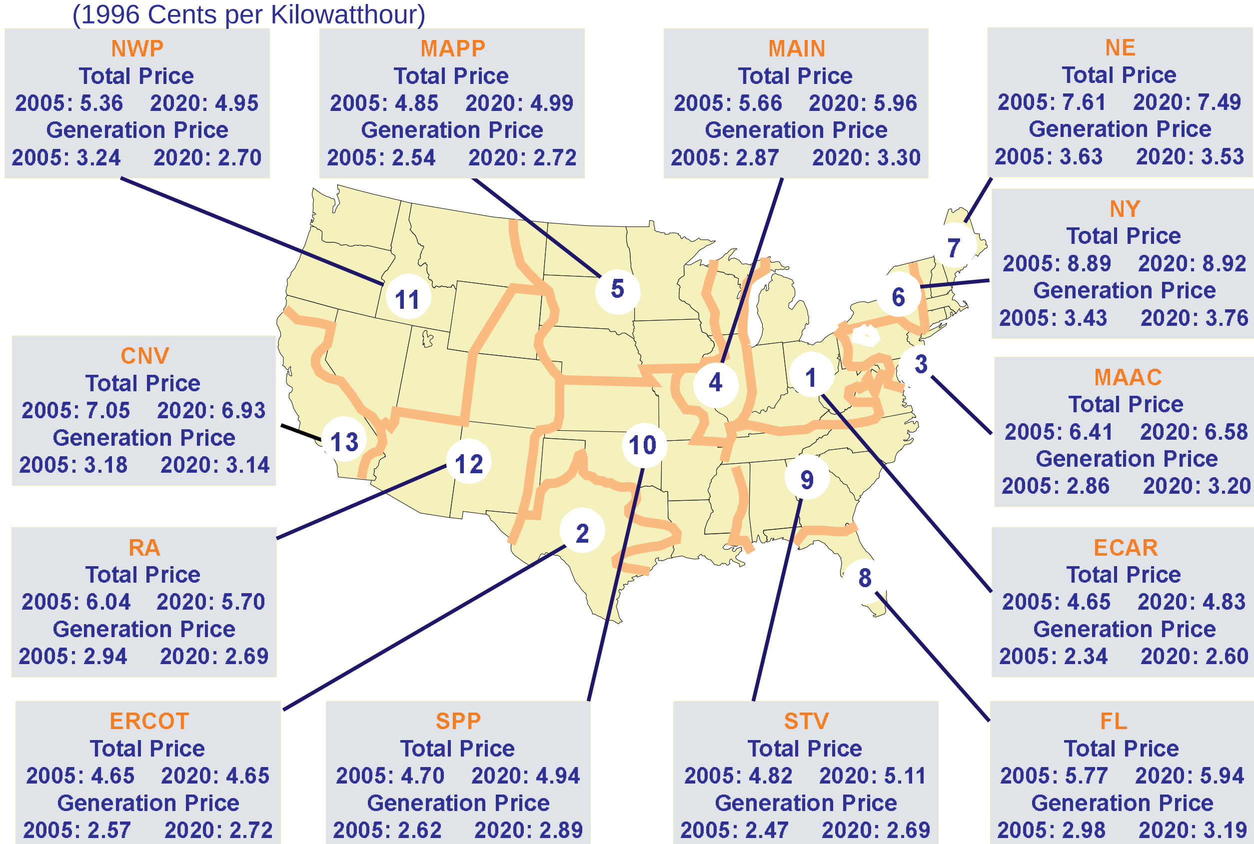
In 2005, the range in generation sector prices across the regions is expected to be less than 1.3 cents (Figure 3). By 2020, the range narrows even further to just over 1.1 cents. The variation in generation prices, especially in the early years, is due primarily to the different mix of plants in the regions. The plant types setting the marginal price, in descending order of operating costs, include: high operating cost oil / gas turbines (although many of these plants can burn either oil or natural gas, most use gas) designed to run infrequently; older, inefficient oil / gas steam plants; newer, more efficient oil / gas combined-cycle plants; and coal-fired plants with low fuel costs. As a result, the regions with the lowest generation prices are those dominated by low operating cost existing coal or hydroelectric plants.

In region 1 (ECAR), more than 85 percent of the total existing capacity is coal or nuclear powered. In regions like this, coal-fired plants will set the marginal price during many hours of the year, especially in the early years of the projections, before a large number of new plants are built (Figure 4). Conversely, regions that rely more heavily on older, less efficient oil and gas steam plants will tend to have the highest competitive generation prices. This is true in regions 6 and 7, New York and New England, both of which have large amounts of oil and gas steam capacity. It is possible that these plants may be retired soon after competition takes hold and, thus, that there impact on prices will be lessened.

Over time, new gas-fired combustion turbine and combined-cycle plants are expected to dominate new power plant additions in all regions. Such relatively low-cost plants are expected to bring down generation costs in almost all regions, especially where they are relatively high today. As a result, existing plants will not play as

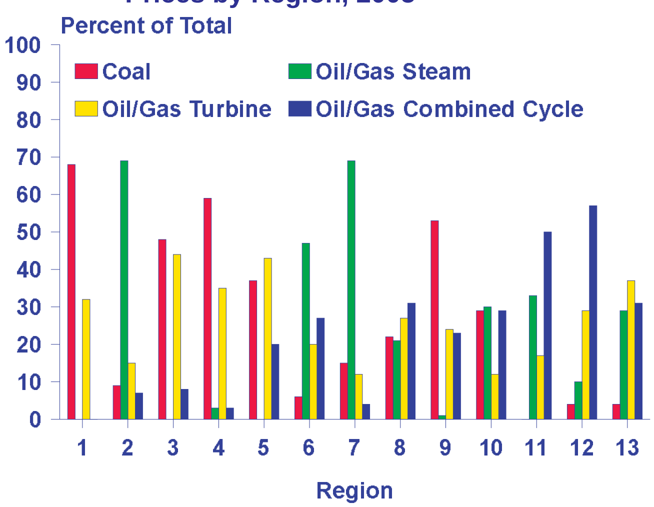
[6] Energy Information Administration, *Petroleum Marketing Monthly*, DOE / EIA-0380(98 / 02) (Washington, DC, February 1998).

Figure 3. Total Electricity Prices and Generation Prices by Region, 2005 and 2020
(1996 Cents per Kilowatthour)



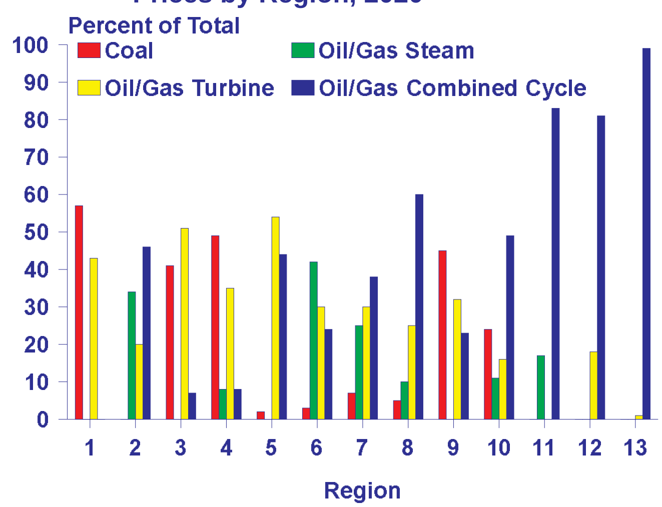
Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

Figure 4. Plant Types Setting Marginal Electricity Prices by Region, 2005



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

Figure 5. Plant Types Setting Marginal Electricity Prices by Region, 2020

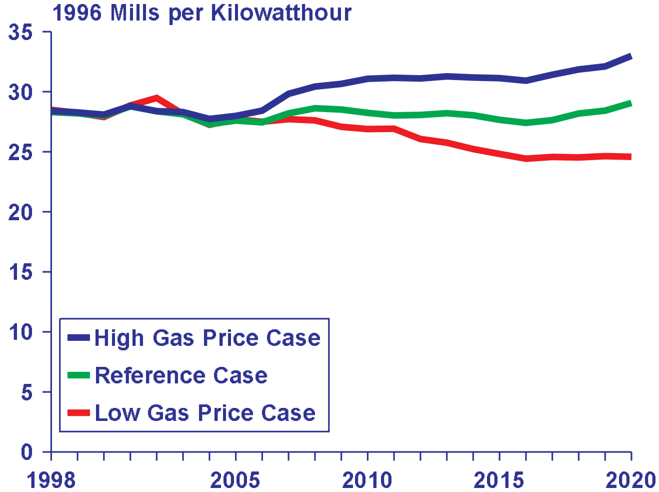


Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

important a role in setting the marginal price in 2020, and the range in generation sector prices across the regions will narrow further (Figure 5).

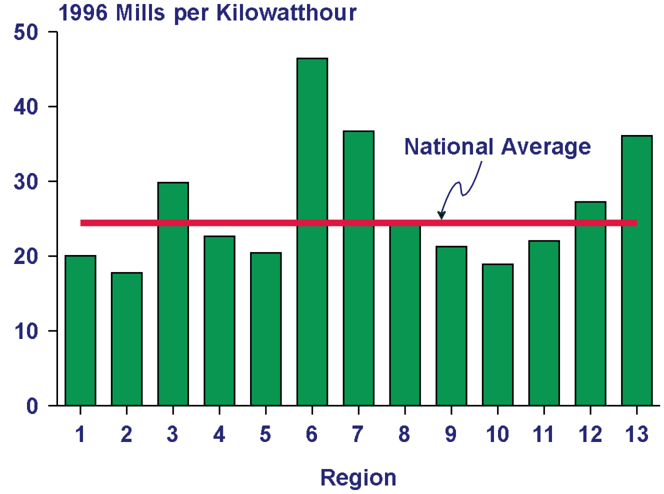
As discussed at the national level in *AEO98*, the competitive generation price will be sensitive to any factors that raise the operating costs of the generators setting the marginal price. For example, if natural gas prices turn out to be higher or lower than expected, competitive generation prices will be directly affected. Figure 6 illustrates this point at the national level. When the price of gas delivered to generators is assumed to be 18 percent higher, the competitive generation price is projected to be 13 percent higher in 2020 than in the reference competitive case. Similarly, when the price of gas delivered to generators is 18 percent lower, the competitive

Figure 6. National Average Generation Prices in Alternative Gas Price Cases, 1998-2020



Source: AEO98 National Energy Modeling System, runs BASECOMP.D101797A, LOGCOMP.D101697A, and HOGCOMP.D101697A (October 1997).

Figure 7. Transmission and Distribution Costs by Region, 2005



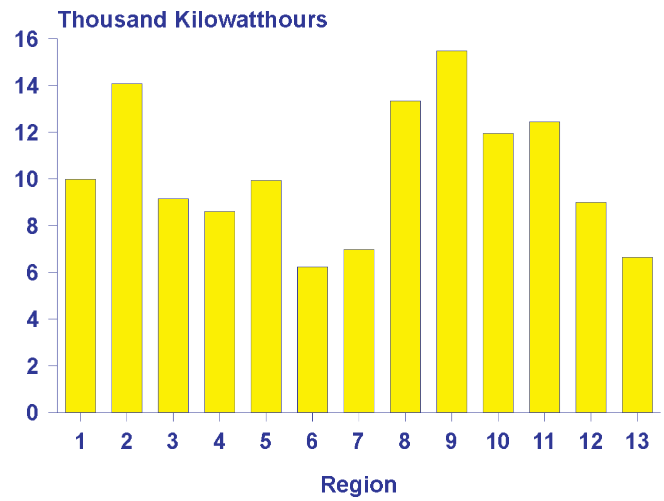
Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

generation price is 15 percent lower in 2020 than in the reference competitive case.

Generation sector prices account for 1.3 cents of the 4.2-cent range in regional prices remaining in 2005. Prices for transmission and distribution services (the vast majority of which are for distribution) account for a much larger share. Across the regions, the projected transmission and distribution prices in 2005 range from less than 2 cents per kilowatthour in the Texas (ERCOT) and SPP regions (regions 2 and 10), to nearly 5 cents per kilowatthour in the New York region (region 6) (Figure 7).

Many factors contribute to the range in transmission and distribution pricing, including regional construction and labor cost differences. One of the most important is the variance in average customer consumption across the regions (Figure 8). Because transmission and distribution system costs consist mainly of the capital costs for wire, poles, substations, and transformers, the per-kilowatthour cost is lower where the level of consumption per customer is higher. In other words, in the Southeast, where climate conditions cause customers to use a relatively large amount of electricity for air conditioning, the capital costs of the distribution system can be spread out over the high consumption base. In contrast, in New York, New England, and California, where cooling needs are less pronounced and alternatives fuels are available for heating, average customer consumption is relatively low and per-kilowatthour transmission and distribution costs are higher, because they are recovered over a much smaller sales base.

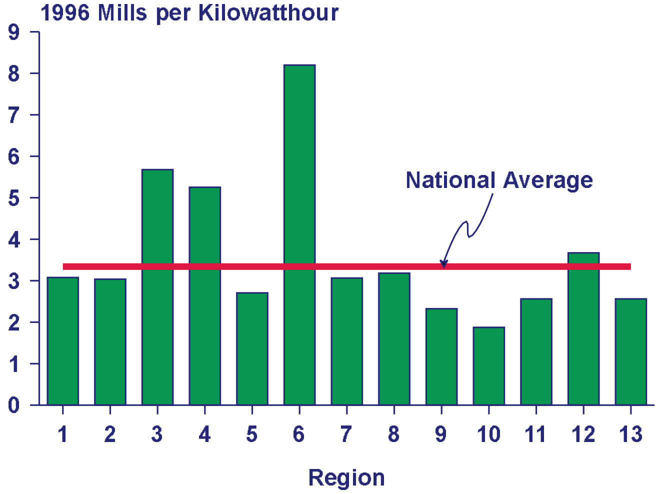
Figure 8. Average Electricity Sales to Residential Customers by Region, 1996



Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report" (1996).

Another factor contributing to the remaining price gap among the regions after generation sector competition is phased in are different regional tax levels. As is the case for gasoline, all the States tax their electric utilities differently. In the generation sector, taxes typically add a few mills (tenths of a cent) per kilowatthour to the price. Across the regions, however, the level varies from 2 to 8 mills per kilowatthour (Figure 9).

Figure 9. Taxes on Electricity Generation by Region, 2005



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

Comparisons with Earlier Results

The projected competitive electricity prices in this report are on average 0.5 cents per kilowatthour lower in 2005 and beyond than those presented in the August 1997 report.[7] The reasons include assumptions of lower construction costs and lower operations and maintenance (O&M) costs, as well as improved historical calibration of general and administrative (G&A) expenses. These updates were made during the preparation for *AEO98*, upon which this analysis is based. The earlier report was based on the *Annual Energy Outlook 1997* (*AEO97*). With respect to the magnitude of the impacts, the adjustments to G&A expenses had the greatest impact.

Power plant construction costs were significantly lower in *AEO98* than those assumed in *AEO97*. For example, in *AEO97* new pulverized coal plants were expected to cost $1,458 per kilowatt (1996 dollars) or approximately $583 million for a typical 400-megawatt plant. In *AEO98*, the same plant was expected to cost only $432 million, or 26 percent less. Similarly, a new 400-megawatt advanced combined-cycle plant was assumed to cost only $229 million ($572 per kilowatt) in *AEO98*, versus $253 million in *AEO97*. The lower cost assumptions reflect the continuing efforts by designers and constructors to develop more economical standardized power plants so that they can remain competitive.

Plant O&M costs can be broken into nonfuel and fuel components. Nonfuel O&M costs include the labor and other services (lubricants, coolants, limestone, rents, etc.) needed to run a plant. Over the past 10 to 15 years, nonfuel O&M costs have declined significantly. Between 1981 and 1995, the nonfuel O&M costs per kilowatthour of generation at coal-fired plants have declined by 22 percent, or approximately 2 percent annually. Over the same period, the number of employees per megawatt of capacity has fallen by 20 percent. Although further declines are far from certain, analysis of recent data shows that, from plant to plant, the costs still vary significantly, and growing competition is expected to increase the pressure to reduce them. As a result, for both *AEO97* and *AEO98* it was assumed that nonfuel O&M costs would continue to decline, falling by an additional 25 percent over the next 10 years. The impact of this assumption was greater in *AEO98*, however, because nonfuel O&M costs were represented for specific plants rather than by plant type as in *AEO97*.

With respect to fuel costs, the projected average fossil fuel prices to power generators are 5 percent lower in 2005 in *AEO98* than they were in *AEO97*. Lower prices for coal, which accounts for over half of the power generated in the United States, is the major reason. As shown in Figures 4 and 5, in some regions of the country, coal-fired plants are often the marginal plants running, especially in the early years of the projections. At the national level, coal prices to power generators in 2005 were assumed to be 11 percent lower in *AEO98* than in *AEO97*. This difference is maintained throughout the projections. Between 1970 and 1996, average minemouth coal prices in real 1996 dollars declined by $4.32 per ton, and they are expected to decline by an additional $5.23 between 1996 and 2020. In *AEO98* the assumed decline is more rapid, as the result of a reassessment of coal mining labor productivity and greater penetration of production from Western surface mines that are less expensive to operate. With respect to natural gas, the story is the opposite: projected prices are higher in *AEO98* than in *AEO97*. Throughout the projection period, natural gas prices to power plants are between 10 and 20 percent higher in *AEO98*.

In the uniform system of accounts used by electric utilities, G&A expenses cover a wide array of cost categories, including employee pensions and benefits, administrative and general salaries, office supplies and expenses, outside services employed, miscellaneous general expenses, and various insurance categories. The majority of these costs are labor related, associated with employee salaries, pensions and benefits. In 1996, investor-owned utilities spent $13.5 billion on G&A, or 12 percent of their total operating costs. G&A expenses are not reported at the plant level, however, and as a result it is not possible to determine the degree to which they reflect plant operating costs.

In competitive markets, a product supplier will be willing to sell the next unit of output at a price equal to the immediate cost of producing it—what in economics is referred to as the short-run marginal cost. Costs that do

[7] Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, DOE/EIA-0614 (Washington, DC, August 1997).

not vary with output are not included in short-run marginal costs. For example, for fossil power plants the key component of short-run marginal costs is fuel costs. To get one more kilowatthour of electricity out, a certain amount of coal, gas, or oil has to be put in.

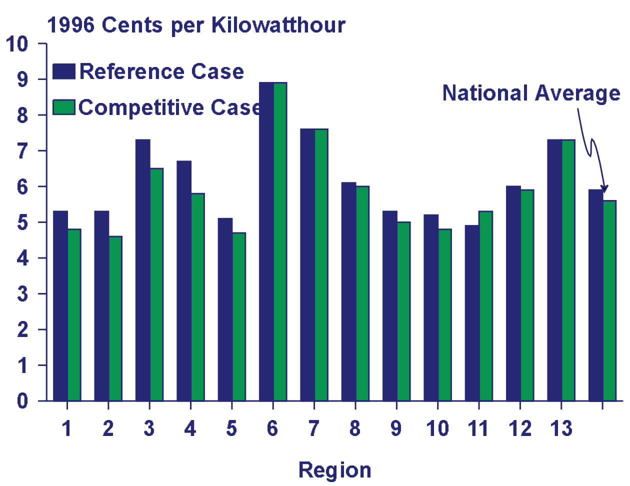
Labor costs for staff working at a plant whether or not it is running at full capacity are not included in short-run marginal costs, because they do not vary with output. However, to the extent that labor costs increase with output (for example, when staffing levels are increased to run a plant at a higher capacity factor), those costs are included in the cost of producing the next kilowatthour.

Unfortunately, because the historical data are not uniformly reported at the plant level, and because regulated operation may not be indicative of how a plant is operated in a competitive market, it is not possible to determine what portion of the G&A costs should be included as part of a supplier's bid price (the same is true for nonfuel O&M costs discussed previously). Modeling experiments were carried out with different portions included in competitive electricity prices. From the experiments it was determined that, unless the majority of the G&A costs were included, competitive generation prices would not be high enough to support the construction of new power plants that would be needed as demand grows. In the previous report, model runs were prepared assuming various levels of inclusion of these costs. In this report, as in the moderate response case of the previous report, all the G&A costs were included in marginal generation costs; however, more recent data were used here, and overall G&A costs were reduced significantly. Including these costs added about 0.2 to 0.3 cents per kilowatthour to the competitive price.

As in the previous report, competitive markets are expected to lead to lower prices relative to cost-of-service regulated prices in nearly all regions through 2010 (Figure 10). Only in the Northwest, where regulated prices are very low, are competitive prices expected to be higher by a small amount. The differences seen in Figure 10 should not be viewed as the total impact of competition. The reference case in this report is not a "no competition" case but includes the impacts of wholesale market competition that has been occurring for many years. The difference between the two cases shown in the figure should be seen as the impact of moving to competitive, marginal cost pricing of generation services to retail consumers. Also, regions 6, 7, and 13 were treated as fully competitive in the reference case, and they show only minute differences between the cases.

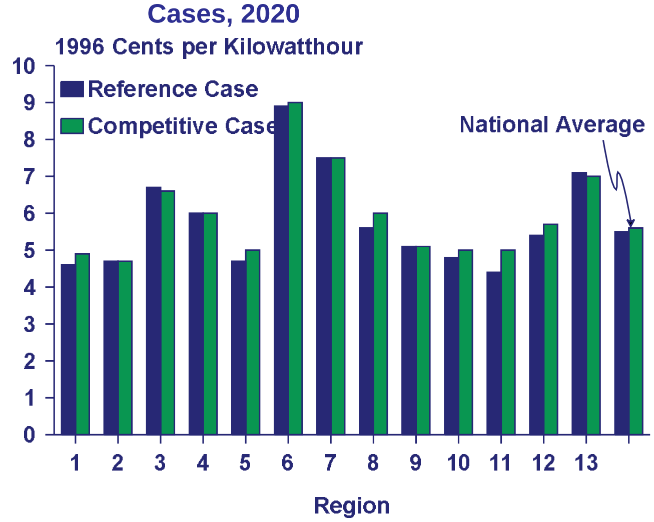
After 2010, the projected competitive prices begin to rise slowly, although in most regions they remain nearly equal to or below reference case prices through 2015. By 2020, several regions have competitive prices slightly above reference case levels (Figure 11). The key to these results is the expected future price of natural gas. These expectations are important because the majority of capacity built to meet growing demand over the next 20 years is expected to be fueled with natural gas. As a result, the impact of natural gas prices on competitive generation prices will grow over time. If natural gas prices turn out to be lower than expected in the *AEO98* reference case, competitive generation prices could be lower than or equal to the projected regulated prices in all regions. However, the opposite is also true.

Figure 10. Total Electricity Prices by Region in the Reference and Competitive Generation Cases, 2010



Source: AEO98 National Energy Modeling System, runs BASECOMP.D101797A and AEO98B.D100197A (October 1997).

Figure 11. Total Electricity Prices by Region in the Reference and Competitive Generation Cases, 2020



Source: AEO98 National Energy Modeling System, runs BASECOMP.D101797A and AEO98B.D100197A (October 1997).

Other factors could also change these results. For example, fully competitive retail generation pricing could lead to greater efficiency improvements than were assumed for this analysis. Also, in the Northwest, some analysts expect that the costs associated with mitigating the impact of large hydroelectric facilities on fish populations will grow in the future. Such potential costs were not included in this analysis; if they were, they could narrow or eliminate the gap between regulated and competitive prices.

As another example, a large proportion of the power produced in the Northwest is produced at federally owned facilities. For this report it was assumed that those facilities would sell their power at competitive market-based rates, even if they were higher than regulated rates. On the other hand, regulators in the Northwest together with Federal authorities may choose an alternative approach, such as returning all or a portion of any windfall profits earned by low-cost public utilities to ratepayers.

Finally, this analysis did not assume any improvement in transmission and distribution service costs, which were assumed to be determined by a regulated cost-of-service methodology. Some State deregulation proposals do include alternatives to the cost-of-service pricing approach used historically for transmission and distribution pricing. Where such proposals are adopted, utilities will have increased incentive to reduce transmission and distribution costs as well as generation costs.

Conclusion

Over the next 10 to 20 years, competitive pressures are expected to narrow the range in electricity prices currently seen across the country, especially prices for generation services. With competitive pricing in the generation sector, by 2005 the range of total electricity prices across regions is expected to decline from the 6.3-cent level seen in 1996 to 4.2 cents. Most of the remaining difference is expected to come from nongeneration sector (primarily transmission and distribution) costs.

Several factors could alter these results. Some cost factors may rise. For example, more resources may be needed to manage the network with a potentially much larger group of suppliers. It is also possible that competitive pressures will lead to greater cost reductions than expected. For example, new technologies may allow suppliers to produce—and customers to consume—electricity more efficiently. The results presented here rest on the assumptions used in preparing the *AEO98* model projections. Further refinements and improvements can be expected as additional data become available from newly emerging competitive electricity markets.

Appendix A

Table A1. Regional Price Components
(1996 Mills per Kilowatthour)

Region	Sector[a]	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Generation	23.39	23.64	24.45	24.71	24.87	24.47	24.45	25.03	25.00	24.80	24.66	24.34	24.77	25.50	25.44	26.01
	T&D	20.04	19.99	19.99	19.99	19.99	20.00	19.99	19.89	19.83	19.84	19.81	19.80	19.72	19.64	19.58	19.56
	Taxes	3.08	3.02	3.01	2.98	2.92	2.83	3.12	2.83	2.76	2.73	2.71	2.76	2.77	2.80	2.69	2.73
	Total	46.51	46.65	47.44	47.68	47.77	47.30	47.55	47.75	47.59	47.38	47.18	46.90	47.26	47.95	47.71	48.30
2	Generation	25.66	24.55	24.49	24.73	24.95	25.28	25.49	25.60	25.83	25.76	25.86	25.82	25.43	26.22	26.73	27.17
	T&D	17.77	17.78	17.86	17.82	17.73	17.64	17.54	17.41	17.31	17.25	17.21	17.19	17.11	17.07	16.99	16.95
	Taxes	3.04	2.76	2.76	2.72	2.65	2.57	2.76	2.56	2.43	2.42	2.34	2.31	2.32	2.34	2.34	2.36
	Total	46.47	45.09	45.11	45.27	45.33	45.49	45.79	45.57	45.57	45.42	45.41	45.32	44.86	45.62	46.06	46.48
3	Generation	28.63	28.84	29.66	29.73	30.76	29.50	29.83	29.79	29.93	30.53	29.40	29.23	29.86	30.68	30.59	32.04
	T&D	29.82	29.61	29.56	29.56	29.53	29.46	29.40	29.24	29.13	29.03	29.03	29.11	29.11	29.04	28.84	28.73
	Taxes	5.68	5.61	5.58	5.47	5.43	5.21	5.33	5.12	5.00	5.11	4.96	4.90	4.96	4.94	4.88	5.04
	Total	64.13	64.06	64.80	64.75	65.71	64.18	64.57	64.16	64.06	64.67	63.39	63.23	63.93	64.66	64.32	65.81
4	Generation	28.70	28.78	30.19	30.73	31.11	30.44	30.76	31.41	31.71	31.60	30.72	30.56	30.63	31.88	31.95	32.98
	T&D	22.65	22.56	22.60	22.52	22.45	22.44	22.38	22.24	22.14	22.10	22.09	22.05	21.95	21.79	21.65	21.57
	Taxes	5.25	5.28	5.24	5.21	5.23	5.06	5.31	5.10	5.02	5.02	4.92	4.88	4.86	4.99	4.96	5.06
	Total	56.61	56.62	58.03	58.47	58.80	57.94	58.44	58.74	58.86	58.72	57.73	57.49	57.44	58.67	58.56	59.60
5	Generation	25.36	25.66	26.39	26.16	25.02	23.66	24.21	23.85	24.57	24.96	25.23	24.18	24.26	25.33	26.45	27.18
	T&D	20.44	20.58	20.55	20.54	20.49	20.50	20.51	20.53	20.47	20.45	20.53	20.55	20.46	20.32	20.18	20.12
	Taxes	2.71	2.72	2.76	2.73	2.63	2.52	2.69	2.49	2.52	2.56	2.63	2.43	2.43	2.48	2.55	2.60
	Total	48.50	48.96	49.70	49.44	48.13	46.68	47.42	46.88	47.56	47.97	48.38	47.17	47.15	48.13	49.19	49.90
6	Generation	34.28	34.35	35.33	35.71	35.42	35.39	35.19	35.44	35.68	35.70	35.26	36.00	36.09	36.08	36.95	37.61
	T&D	46.43	46.02	45.75	45.50	45.32	45.11	44.95	44.70	44.47	44.32	44.21	44.08	43.96	43.87	43.63	43.46
	Taxes	8.20	8.14	8.24	8.24	8.12	8.08	8.28	7.95	7.92	7.89	7.85	7.95	7.97	7.95	8.07	8.17
	Total	88.91	88.51	89.32	89.45	88.86	88.58	88.42	88.09	88.08	87.91	87.32	88.02	88.02	87.89	88.64	89.24
7	Generation	36.30	35.21	35.89	36.17	35.52	35.51	35.15	34.41	34.94	35.44	34.55	34.49	34.18	34.59	34.85	35.26
	T&D	36.70	36.71	36.83	36.87	36.90	36.90	36.88	36.88	36.87	36.86	36.87	37.08	37.17	37.11	37.00	36.95
	Taxes	3.06	3.00	2.97	2.94	2.88	2.85	2.97	2.72	2.71	2.71	2.83	2.71	2.60	2.65	2.61	2.64
	Total	76.06	74.92	75.69	75.98	75.30	75.26	75.01	74.02	74.52	75.01	74.24	74.28	73.95	74.35	74.47	74.85
8	Generation	29.82	29.97	30.49	31.19	31.21	31.47	31.05	31.09	31.70	31.38	31.25	31.33	31.06	31.15	31.70	31.87
	T&D	24.73	24.69	24.71	24.71	24.73	24.82	24.82	24.82	24.83	24.92	24.91	24.94	24.86	24.77	24.73	24.69
	Taxes	3.18	3.14	3.13	3.13	3.09	3.08	3.17	3.04	3.02	2.97	2.92	2.93	2.89	2.83	2.84	2.84
	Total	57.73	57.79	58.34	59.03	59.02	59.36	59.03	58.94	59.55	59.27	59.07	59.19	58.81	58.74	59.26	59.39
9	Generation	24.65	24.91	25.37	25.40	25.82	25.95	26.09	25.72	25.98	25.86	25.52	25.31	25.72	25.94	26.38	26.86
	T&D	21.27	21.37	21.46	21.57	21.66	21.78	21.86	21.90	21.93	22.06	22.15	22.20	22.27	22.31	22.34	22.32
	Taxes	2.32	2.26	2.22	2.16	2.14	2.11	2.16	2.03	2.02	2.01	1.94	1.93	1.93	1.93	1.93	1.93
	Total	48.24	48.54	49.05	49.13	49.62	49.85	50.11	49.65	49.93	49.93	49.61	49.44	49.91	50.18	50.64	51.11
10	Generation	26.22	26.36	26.76	27.22	26.92	27.35	27.27	27.54	27.44	27.14	27.30	27.02	27.19	27.89	28.05	28.94
	T&D	18.90	18.88	18.88	18.86	18.84	18.82	18.80	18.75	18.73	18.77	18.76	18.75	18.69	18.57	18.49	18.47
	Taxes	1.87	1.86	1.85	1.86	1.86	1.86	2.09	1.90	1.86	1.93	1.85	1.90	2.01	2.01	2.01	2.01
	Total	47.00	47.10	47.48	47.95	47.62	48.04	48.16	48.18	48.04	47.84	47.91	47.67	47.89	48.47	48.55	49.41
11	Generation	32.43	29.44	31.43	33.83	31.79	29.64	27.75	27.91	28.17	26.26	26.10	26.14	27.68	26.82	26.93	27.00
	T&D	22.03	21.82	21.61	21.49	21.41	21.33	21.19	21.11	21.08	21.06	21.02	21.00	20.94	20.82	20.69	20.61
	Taxes	2.56	2.35	2.42	2.51	2.38	2.23	2.16	2.07	2.06	1.94	1.90	1.87	1.95	1.90	1.87	1.87
	Total	57.03	53.61	55.46	57.83	55.58	53.20	51.10	51.09	51.31	49.25	49.02	49.02	50.57	49.54	49.49	49.48
12	Generation	29.44	28.78	29.41	29.09	28.51	27.97	27.74	28.00	27.72	27.15	26.43	26.30	26.11	27.54	26.85	26.92
	T&D	27.25	27.23	27.15	27.18	27.25	27.29	27.23	27.21	27.18	27.26	27.34	27.41	27.43	27.42	27.26	27.18
	Taxes	3.67	3.55	3.56	3.46	3.34	3.27	3.33	3.19	3.10	3.09	3.08	2.97	2.89	2.97	2.90	2.90
	Total	60.35	59.56	60.13	59.73	59.10	58.53	58.30	58.40	58.01	57.50	56.84	56.67	56.43	57.93	57.01	57.00
13	Generation	31.80	32.46	33.23	34.32	33.77	34.60	32.74	32.09	31.58	31.80	30.64	29.42	28.94	29.77	30.20	31.37
	T&D	36.09	35.84	35.87	35.92	35.91	35.89	35.68	35.55	35.59	35.77	35.93	36.14	36.09	35.97	35.92	35.93
	Taxes	2.56	2.46	2.42	2.42	2.32	2.32	2.32	2.14	2.09	2.16	2.03	1.98	1.97	1.97	1.97	1.99
	Total	70.45	70.76	71.51	72.66	72.00	72.82	70.74	69.78	69.25	69.74	68.61	67.55	66.99	67.71	68.09	69.29
National	Generation	27.60	27.44	28.20	28.62	28.51	28.24	28.03	28.07	28.21	28.04	27.66	27.41	27.63	28.18	28.42	29.07
Average	T&D	24.43	24.37	24.36	24.34	24.32	24.32	24.28	24.18	24.14	24.17	24.18	24.21	24.17	24.09	24.00	23.95
	Taxes	3.34	3.26	3.25	3.22	3.16	3.09	3.22	3.02	2.97	2.97	2.90	2.89	2.90	2.90	2.89	2.92
	Total	55.38	55.07	55.80	56.18	55.99	55.64	55.52	55.27	55.33	55.18	54.74	54.51	54.70	55.18	55.31	55.93

[a]T&D = transmission and distribution sector. Taxes = taxes on generation.
Note: 1 mill = 0.1 cent.
Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

An Exploration of Network Modeling: The Case of NEPOOL

by
James G. Hewlett, Douglas R. Hale, Thanh Luong, and Robert T. Eynon

As competitive electricity markets evolve, the pricing of services for electricity transmission—based on marginal rather than average costs that are used currently—will become increasingly important. To determine whether marginal cost pricing of transmission services will affect the transmission representation in the National Energy Modeling System (NEMS), a detailed model of the New England transmission network was constructed and tested. Electric power flows on a transmission network can be modeled using either a simple linear model (representing direct current flow) or a more complex nonlinear model (representing alternating current flow). This preliminary analysis indicates that a full alternating current analysis is superior to a simple direct current analysis for these purposes. The results also indicate that a more detailed analysis of the transmission network should be performed to make a final determination as to whether or not changes are needed in NEMS.

Introduction

This paper presents some preliminary results of an ongoing analysis of electricity transmission issues.[1] The overall objective of the project is to examine how the physical, technical, and institutional arrangements for the electric transmission network affect electricity markets. The analysis was undertaken because transmission services are being opened up to competition and, as a result, could alter both the electricity prices that customers will face and the fuels used to generate electricity. Currently the price of transmission services is set by State public utility commissions on the basis of average costs. Consequently, even if the nature of the transmission system (i.e., the number, length, and capacity of the transmission lines) affects costs at the margin, the use of average cost pricing tends to spread the resulting expenditures over all sales. Given this type of pricing, such transmission factors have little effect on the price of electricity. The recent initiative by the Federal Energy Regulatory Commission (FERC) under Orders 888 and 889, mandating that owners of transmission lines (mostly investor-owned electric utilities) make them available to all customers on an equal basis, is expected to bring new providers of electricity generation services into the marketplace and result in new pricing rules that include the costs of bottlenecks on the transmission network.[2] The FERC action, coupled with legislation by the States to open electricity generation services to competition, is expected to lead to lower electricity prices and a variety of new options for consumers.

In the initial phase of this work, a transmission network model of the New England Power Pool (NEPOOL) was developed to determine what impacts the above changes would have on electricity markets. This network analysis tool[3] addresses the approximated flow of power along transmission lines, based on the physical laws of nature, which cause power to flow on paths that are independent of the contract path. That is to say, when power is introduced into the transmission network for delivery to some other point in the network, the actual power flow is different from the path intended by the supplier and consumer (the contract path). In reality, every link in the network is affected to some degree. This complicating factor makes the operation of the network more difficult than operating a pipeline, where the flow can be regulated to a certain extent by adjusting valves.[4]

There is another consideration that further complicates the operation of transmission networks. Electricity has two inherent components, called "real" and "reactive." Real power is the power consumed in resistive loads, such as a hair dryer or a toaster. Reactive power is associated with magnetic fields, such as those found in the motor of a refrigerator. The amounts of real and reactive power that flow in the transmission network vary with customer needs. It is the job of the operator of the transmission system to assure that the levels of both real and reactive power are balanced. The operator must provide sufficient reactive power to assure that the transmission network remains stable, with the desired frequency and

[1]The authors would like to acknowledge the contribution of Joseph Mulholland, Office of Energy Efficiency, U.S. Department of Energy, for his engineering and computational analysis of electricity imports.

[2]See Federal Energy Regulatory Commission, Docket Nos. RM95-8-000, RM94-7-001, RM95-9-000, and RM96-11-000 (April 24, 1996).

[3]The model used is the *PowerWorld* simulator, jointly developed by several universities led by the University of Illinois.

[4]It should be noted that control of natural gas pipelines has become an increasingly challenging task as a result of the restructuring of the natural gas industry.

voltage levels staying within prescribed tolerances in order to prevent system failures or blackouts.

Considerations of network stability sometimes force transmission operators to use generators in particular places in the transmission network, even though cheaper sources of power might be available elsewhere in the system. For example, a given generator may be dispatched to meet a need for reactive power, because reactive power by the laws of physics does not travel the same way as real power does. Whereas real power can travel over long distances, reactive power must be provided close to where it is needed.

The issues of actual power flow and stability considerations must be addressed in a network analysis. Simplistic representations of power flow based on contract paths that ignore reactive power have little value. This is especially true when pricing issues are of interest. Because restructuring entails the unbundling of transmission services from other services, transmission costs become more important than they were when all the costs of providing electricity services were lumped together. In order to estimate the price of transmission services, the costs of moving real power from one place to another must be augmented by the cost of "ancillary services," which include reactive power and voltage control.[5]

The above discussion of network considerations provides a basis for the modeling approach used in this analysis. The analysis uses a complete alternating current model that incorporates both real and reactive power as well as pricing of transmission services. Although this approach is computationally complex and data intensive, it accurately reflects actual transmission operations.

This analysis addresses three questions related to transmission:

1. If the structure of the transmission network is assumed to be fixed, will the nature of the transmission system have major effects on the operation of generating facilities?
2. Will the existing structure of transmission networks result in substantial differences between marginal and average transmission costs?
3. Can transmission capability issues be analyzed without considering the unique characteristics of alternating electric current?[6]

The National Energy Modeling System (NEMS), used by the Energy Information Administration (EIA) to produce mid-term forecasts (20 to 25 years), is a large integrated model of the energy sector. The model accounts for transmission-related capital and operating expenditures when computing the costs to be recovered from consumers. Additionally, based on data obtained from the North American Electricity Reliability Council (NERC), NEMS specifies limits for power traded between regions. Because of the integrated nature of NEMS, the model endogenously solves for the equilibrium set of energy prices, using iterative solution techniques, such that supply will equal demand.

Even the simplest nationwide electricity network model can consist of more than a thousand nonlinear equations, which must be solved simultaneously to compute power flows. Thus, it is not computationally practical to include a direct representation of the actual electricity transmission system in NEMS. Indeed, the inclusion of a electricity network model in NEMS would increase the computing requirements more than tenfold. Given this consideration, it is necessary to use other means to determine the magnitude of the effects the transmission system could have on the cost of providing generating services. If the effects are small, then the current representation of the transmission network in NEMS is adequate. If not, a methodology will need to be developed to simulate the results of a detailed transmission network in an aggregate regional model such as NEMS. This analysis focuses on gaining insights about the order of magnitude of these effects.

The organization of the remainder of this paper is as follows. The next section discusses the questions in more detail, and how the unique characteristics of electricity affect the results. To determine the potential importance of the questions, a model of the New England Power Pool (NEPOOL) was used. The two following sections describe the model and the necessary data. The final two sections present some initial answers to the three questions posed, summarize the results, and describe future directions for this work.

Electricity Networks, Transmission Capability, and Marginal Generation and Transmission Costs

Because an electricity transmission network provides the same function as any other transportation system—i.e., it ships the commodity from the source of production to the end user—it is tempting to view the movements of power as a typical transportation problem. The "transportation" of electricity from the generation source to the end user is, however, very different from the movement of other commodities. The unique

[5] For a description of ancillary services, see Electric Power Research Institute, *Transmission Service Costing Framework, Volume 2: Framework Description and Application*, EPRI TR-105121-V2 (Palo Alto, CA, April 1995).

[6] As noted in the discussion that follows below, the most important characteristic of alternating current is the fact that voltage can vary across the network.

characteristics of electricity make the examination of the three questions posed above, computationally more involved and conceptually more difficult.[7]

Measurement of the Capability of a Transmission System To Move Power

As opposed to many other commodities, the flows of electricity over a given line are influenced by the generation, loads, and flows of power over the entire network, as determined by Kirchhoff's laws of physics.[8] Thus, the flows of electricity over all the lines in a network are interdependent and are not "point to point." The interdependent nature of electricity flows implies that the capacity of the entire network, not just certain subsets of it, must be examined. Additionally, the ability to move power over one part of a network will be influenced by the actions of all the generators and end users that are connected to it. Thus, one party's access to a network will in part depend upon the actions of others.

Electricity is a multidimensional commodity, and the capability of a transmission network must be evaluated with respect to all its dimensions. That is, the output of a generator or the amount of power used by an electrical device is typically measured in watts of real power—for example, the maximum output of a certain power plant is 500 megawatts, or the amount of power needed to operate a certain motor is 250 watts. Without the needed amount of real power, most electrical devices will simply not operate. Many electrical devices are also designed for a given voltage—110 volts for most household appliances. If the voltage is less than the designed level, the electrical device will not work properly. If the voltage is greater than the designed level, the device will be seriously damaged.[9] Thus, given that the transmission system is capable of transporting the needed amount of real power, if the voltage, also a function of the entire network, is not sufficient, most electrical devices will not operate.

One way of controlling the voltage level in a network is to alter the amount of reactive power supplied by generators. Reactive power is used by any electrical device that has a coil or motor. It is sometimes called "wattless" power, because in a strict sense of the word, a circuit (an electrical device connected to a source of electricity) that just contains reactive power uses no real power; nevertheless, without it many electrical devices would not operate. More important, at any point in time, both reactive and real power are flowing through power lines. Reactive power is measured in terms of voltage-amperes reactive (VAR).

Because both real and reactive power flow through power lines, the capacity of a power line is measured in terms of voltage-amperes (VA), or what is called "apparent power." The amount of apparent power flowing through the line is equal to the square root of the sum of the squared amounts of real power (*WATT*) and reactive power (*VAR*):

$$VA = \sqrt{(WATT^2 + VAR^2} \quad .$$

Any evaluation of the capacity of a transmission system that focuses only on real power flows could lead to incorrect conclusions, particularly if the amount of reactive power is relatively large.

The interdependent nature of electricity networks and the fact that voltage variability can be important suggest that a complete alternating current (AC) network model can be computationally complex. A question of interest is whether there are computationally simpler methods of approximating such a network. The simplest approximation would be to ignore all the interdependence issues along with voltage (and reactive power) considerations and treat electricity transmission as a typical transportation problem.

A second approximation is to assume that the current just moves in one direction. The result of this assumption is a "direct current" (DC) model, which accounts for all the interdependence associated with electric power flows but, by assuming that all power moves in one direction, ignores the issues of reactive power and voltage control, which are unique to AC systems. A DC model is somewhat more complex than the traditional transportation model, but it is much simpler than the third alternative—a complete AC model that deals explicitly with voltage and reactive power issues.[10] If voltage control and reactive power are important, then a computationally complex AC model must be used.

[7]For example, a typical transportation problem is as follows: Suppose there are two ways to get commodity *Z* from point *A* to point *E.* One way goes through points *B* and *C* and the second goes through point *D*. The typical problem is to find the least-cost (or quickest) route from *A* to *E.* As noted below, the typical transportation algorithm and computer software used to analyze such a transportation problem cannot be used for electricity. Additionally, in a perfectly competitive world, according to the traditional transportation model, the price of good *Z* at location *E* cannot exceed the incremental cost of producing good *Z* plus the cost of transporting it from location *A* to location *E.* In electricity networks, however, such relationships may not be true. See W.W. Hogan, "Contract Networks for Electric Power Transmission," *Journal of Regulatory Economics* (1992), pp. 211-242.

[8]See F.C. Schweppe, M.C. Caramanis, R.D.Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic Publishers, 1988).

[9]Voltage and power are related according to the following equation: $P = V \times I$, where *P* is power measured in watts, *V* is voltage measured in volts, and *I* is current measured in amperes. Voltage is a measure of force, and current is a measure of the rate of flow of the electrons through a wire.

[10]See F.C. Schweppe, M.C. Caramanis, R.D.Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic Publishers, 1988); and S. Herman, *Delmar's Standard Textbook of Electricity* (Albany, NY: Delmar Publishing Company, 1995).

Interaction Between Transmission and Power Plant Operations

Although a generator produces both real and reactive (wattless) power, the day-to-day dispatching of a unit is generally based on the short-run marginal cost of producing real power. That is, almost all utilities use "merit-order" dispatching, with all units ranked according to their short-run marginal costs (per-kilowatthour fuel expenditures and some nonfuel operations and maintenance costs). Then, the units are dispatched on the basis of increasing marginal costs. There are, however, times when units are operated regardless of their per-kilowatthour costs. This is called "out-of-order" dispatching. In some cases, regardless of costs, a specific unit must generate real and reactive power to maintain necessary voltage levels.[11] Transmission constraints and very high line losses may also require a unit to be dispatched out of order. Finally, for some generating units the "startup costs" (i.e., the costs of going from zero to some positive level of output) can be substantial. In such cases, it may be more economical to operate the unit at some minimum level than to cease operation and then restart it. In general, the major cost of out-of-order dispatching is the increased variable production costs resulting from the increased operation of higher cost units. In the past, such cost increases would be averaged over all kilowatthours of electricity consumed.

Stated somewhat differently, in some sense, the production of electricity can be considered to be a process whereby a generator produces "joint products"—real power and voltage control.[12] Simple economic theory states that the supply of a joint product will be influenced by the price of both joint products. The marginal kilowatthour cost is essentially the price of real power. In a pure economic dispatch, only the price of real power matters. When out-of-order dispatching occurs, the supply of one of the joint products, real power, is influenced by the "price" of the other, voltage control. In the past, there was no explicit price for voltage control. In the restructured industry, however, voltage control is an ancillary service for which an explicit price will be charged.

Because of computational factors, most large models of the energy sector do not contain any direct representation of electric power networks. Thus, by necessity these models employ pure merit-order dispatching. Additionally, when modeling the competitive pricing of electricity, most analyses assume that prices will equal marginal generation costs (plus some other factors) and that dispatching patterns will also affect marginal generation costs. In a pure economic dispatch, the incremental generation costs for the entire system will equal the marginal cost of the most expensive (in terms of short-run variable costs) plant generating power. If, however, the most expensive unit is operating because of other considerations, such as voltage control, its output will be essentially fixed. In such cases, a lower cost unit will be at the margin, and the system-wide short-run marginal cost will be determined by the variable cost of that unit.

In short, as compared with cases in which the marginal generation costs are estimated using pure merit-order dispatching of all units, out-of-order dispatching will tend to cause system-wide marginal generation costs to be overstated. It is, therefore, useful to determine the frequency of out-of-order dispatching and, more importantly, how estimates of fuel use are affected by this type of dispatching. An objective to this paper is to obtain some insights about the size of this overstatement of prices.[13]

Short-Run Marginal Cost Pricing of Transmission

The final issue addressed in this paper is the pricing of transmission services. In the past, average cost pricing of transmission was used by all State and Federal regulatory agencies. Thus, the utility recovered all the capital costs associated with transmission and distribution by means of depreciation charges and earned a return on the undepreciated balance. All the operating costs were recovered in the year they were incurred. The costs associated with line congestion and average lines losses were equally spread over all consumers. Because transmission systems were designed to minimize congestion

[11]In general, the amount of reactive power produced by a generator can be altered without affecting fuel costs or operating efficiency. This is done by changing the strength of the magnetic field in the rotor of the generator. See, for example, S. Herman, *Delmar's Standard Textbook of Electricity* (Albany, NY: Delmar Publishing Company, 1995), p. 822 and pp. 408-409. In some cases, however, the production of reactive and real power are not independent. In such cases, changing the amount of reactive power would indirectly affect fuel costs, etc.

[12]Two products that are jointly produced from the same process are called joint products. Mutton and wool, jointly produced by raising sheep, are a good example of joint products. In the energy area, motor gasoline and jet fuel is another example of a joint product, since both are produced from crude oil.

[13]An issue of some importance in many restructuring proposals is the treatment of the units that must operate for reasons such as voltage control. In both the United Kingdom and the United States, plants that are always "must run units" (i.e., nuclear and large hydroelectric power plants) do not participate in competitive bidding schemes. An owner would prefer to have a plant declared "must run" by the regulatory authorities because it eliminates all the uncertainties of the bidding processes. Additionally, there is the issue of the pricing of power from units whose bid is not accepted because the bids are too high, but that must still operate because of voltage control or other factors. In the United Kingdom, the owners of such units receive their bids. If they could correctly guess when a unit *must* be operated—regardless of the bid price—for the purpose of voltage control, they would bid very high prices.

(overloaded power lines) and equalize line losses throughout the system, the equal allocation of these costs across all consumers probably did not result in any major economic distortions.[14]

Because the siting new transmission lines is becoming problematic, the redesign of transmission systems to accommodate changes in the geographic distribution of generators and loads may not be possible.[15] As a result, congestion and line losses and their associated costs could increase in the future. Although transmission and distribution will still be regulated, there is some movement toward marginal cost pricing of these services. One pricing scheme that has received considerable attention is to set electricity prices equal to the short-run marginal costs of both generation and transmission.

The short-run marginal cost of generating and transmitting electric power has been derived by Schweppe et al.,[16] who have shown that they include the following three factors:

1. Marginal generation costs for the entire system
2. Accumulated congestion costs from the generation source to the end user[17]
3. The value of accumulated marginal line losses.

The first factor will be the same regardless of where the load is located on the grid. The second and third factors are highly dependent on the location of the consumer, resulting in location-specific prices. Because of the interrelated nature of electrical systems, all three factors will be influenced by the actions of all the generators and consumers connected to the grid. This implies that the estimation of location-specific prices can be computationally complex.

By definition, short-run marginal costs do not include any fixed capital or operating costs. Because those costs are very large, short-run marginal cost pricing of transmission services would not recover all the fixed costs. In reality, there would have to be some type of additional charge to make any marginal-cost pricing proposal economically viable. The "prices" used in the present analysis are based solely on short-run marginal costs, without addressing the recovery of fixed costs. Thus, the "prices" computed here are incomplete estimates of actual prices.

Because most energy models do not contain a direct representation of electricity networks, marginal transmission costs cannot be computed directly. Thus, one question of interest is whether marginal line losses and congestion are sufficient to cause major differences between the average and marginal costs of transmission. Moreover, such models operate at a fairly high level of aggregation (i.e., Census or NERC regions), and therefore the intraregional distribution of prices is not relevant. Computational issues aside, it could still be possible to derive an aggregate marginal-cost-based price for each region. That single price could be interpreted as the demand-weighted average of all location-specific intraregional marginal costs. Large intraregional variations in prices could, however, result in an aggregation problem. For this reason, the potential intraregional distribution of marginal costs is of interest.

In addition to these modeling questions, there are some broader public policy issues related to location-specific marginal cost pricing of electricity transmission. Location-specific prices that equal marginal costs will send the "correct" signal to consumers and producers of electricity; however, the estimation of location-specific prices is computationally complex. Moreover, the administrative and billing costs could be substantial. Thus, if there is little variation in location-specific prices, the costs of computing them may exceed the benefits.[18]

The NEPOOL Model

The *PowerWorld* network model was used for this analysis. The model consists of an electrical network, an economic component describing costs and demands, and algorithms for calculating power flows and prices. It is also a full AC representation that explicitly includes real and reactive power, line losses, congestion, and

[14]In some cases, the State public utility commissions allocated some of the distribution-related capital costs (e.g., special transformers or capacitors for large industrial customers) to the customers receiving the benefits; however, all the costs associated with long-distance transmission tended to be allocated equally to all consumers.

[15]According to conventional wisdom, problems with siting arise because of population growth and environmental/health concerns about long-distance transmission lines. For counter arguments see, for example, J.D. Finney, H.A. Othman, and W.L. Rutz, "Evaluating Transmission Congestion Constraints in System Planning," *IEEE Transactions on Power Systems*, Vol. 12, No. 3 (August 1997), pp. 1143-1151; J. Rajaraman and F. Alvarado, "Determination of Location and Amount of Compensation To Increase Power Transfer Capability," *IEEE Transactions on Power Systems*, Vol. 13, No. 2 (May 1998), pp. 294-301; and, T.L. Le and M. Negnevitsky, "Network Equivalents and Expert System Application for Voltage and Var Control in Large-Scale Power Systems," *IEEE Transactions on Power Systems*, Vol. 12, No. 4 (November 1997), pp. 1440-1455.

[16]See F.C. Schweppe, M.C. Caramanis, R.D.Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic Publishers, 1988).

[17]Congestion occurs when a line is overloaded. When this occurs, there will be a different flow of power that increases line losses that in turn changes the dispatching of all the generating units. The congestion costs are the resulting increases in production costs.

[18]This paper does not examine the pricing of reactive power and voltage control, which generally are regarded as ancillary services. It must be noted that there has been very little discussion of exactly how ancillary services will be priced and how (or if) their capital costs will be recovered.

generator costs and operating constraints. The model was used to simulate NEPOOL power flows. The next two sections describe *PowerWorld*, NEPOOL, and the data used for the model analysis.

The *PowerWorld* Computer Model

The *PowerWorld* software solves three related problems for an AC system[19]

1. Power flow with economic dispatch
2. Optimal power flow
3. Optimal economic equilibrium.

The power flow with economic dispatch problem is to find the least costly way to meet fixed demands for power at specific locations by assigning attainable operating levels to generators. Generators for which cost estimates are not available are fully committed (assuming that they are run regardless of cost) at the capacity shown on FERC Form 715, "Annual Transmission Planning and Evaluation Report."[20] Generators with minimum operating levels are always dispatched. All other generators can be run at any level up to their capacity. Generator assignments are consistent with the physical laws governing power flow (Kirchhoff's laws) and account for line losses but not for line limits (congestion). Costs are the sum of the costs of running the generators. When the demands cannot be met, the power flow problem is said to be infeasible. A viable solution would require either lower demands, relocated demands, more generation capacity, or a different transmission line configuration. Economic dispatch and merit-order dispatch are the same when all generators can be dispatched at any level up to capacity and there are no losses.

In order to dispatch a generator *PowerWorld* requires a cost curve of the form

$$Total\ Cost = a + b\,g + c\,g^2 + d\,g^3 \quad ,$$

where a, b, c, and d are constants to be estimated and g is the output from the generator. When there are multiple units at a bus, the bus cost curve is constructed by summing the individual cost curves horizontally.[21] The average variable cost (AVC) is

$$AVC = b + c\,g + d\,g^2 \quad ,$$

and the marginal cost (MC) is

$$MC = b + 2c\,g + 3d\,g^2 \quad .$$

The only costs that matter for the computation of efficient prices and generation are the marginal cost curves. The marginal cost, which is the sum of fuel and variable operations and maintenance costs per kilowatthour generated, is approximately b when generators are operating normally. When generation gets near its maximum, the curvature parameters, c and d, become important. The estimates of these parameters are discussed below.

The optimal power flow problem is to find the least costly way to meet fixed demands while satisfying line constraints. A solution to the optimal power flow also satisfies all the constraints in the power flow problem. If the original power flow problem is infeasible, then the optimal power flow is too. If lines are not congested in the optimal power flow, then its solution will be the same as the power flow. Both problems assume that the demand for electricity is fixed and does not respond to costs or prices. That is, given fixed demands, the optimal power flow calculates the competitive prices and quantities. This is a true competitive price in the sense that it includes all relevant operating constraints, network effects, and voltage standards.[22]

These optimization problems have real-world counterparts. Power flow with economic dispatch is essentially the approach being followed in the United Kingdom, where some difficulties have occurred because congestion is ignored and because the differences in incremental losses at each location are averaged out. Australia and New Zealand have adopted systems that approximate an optimal power flow, explicitly recognizing network effects. The result in Australia is that competitive prices go up quickly as lines become constrained.

The New England Power Pool

NEPOOL is one of three tight power pools in the Northeast region of the United States. It was established in September 1971 to serve the New England region (Maine, Vermont, New Hampshire, Connecticut, Rhode Island, and Massachusetts). Currently there are more than 130 participants in NEPOOL, including a variety of nontraditional utilities such as power marketers, exempt wholesale generators, and independent power producers. The power travels over about 8,000 miles of transmission lines, belonging to about 29 transmission

[19] An accessible reference to *PowerWorld* is *PowerWorld Simulator Version 4.1* (Urbana, IL: PowerWorld Corporation, October 1997).

[20] Because these units are not economically dispatched, costs are not relevant; therefore, an arbitrary cost of 1 cent per kilowatthour was used.

[21] A bus is any node or connection point in a transmission network where electrical devices come together.

[22] The optimal economic equilibrium is to assign generation and demands that maximize net social benefit consistent with a feasible power flow. Net social benefit is benefit less cost. Benefit is taken as the area under the demand curve (consumers' surplus), and cost is usually just the sum of generation costs. Because of the lack of location-specific price and quantity data, the requisite demand curve estimates do not exist. It is not possible to calculate this solution for NEPOOL. See J. Weber, T. Overbye, and C. DeMarco, "Inclusion of Price Dependent Load Models in the Optimal Power Flow," accepted for presentation at the 1998 Hawaii International Conference on System Sciences (1998).

owners. The original cost of the transmission facilities was about $3.3 billion.

The pool has operated as a single entity dispatching generators within the pool to meet regional demands. In September 1996, NEPOOL's Executive Committee announced plans to replace its dispatching operations with an independent system operator (ISO) to satisfy FERC's Order 888 requirement to reform access to power pools. On June 25, 1997, the FERC conditionally approved creation of the ISO. The ISO now has operating control of NEPOOL's transmission and generation facilities.

The representation of NEPOOL used here consists of 148 buses, comprising 85 generators, one DC line that is represented as a generator equivalent (Sandy Point, bus #17896), 82 load buses, the high-voltage AC lines connecting them, and two DC lines from Canada.[23] The smallest generation bus is 10 megawatts, the smallest load is 3 megawatts, and the AC lines are mostly 345 kilovolts. The input data for the NEPOOL model are aggregated from the data appearing on FERC Form 715, summer peak 1995. *PowerWorld* was used to aggregate the data to represent only high-voltage lines. The representation of NEPOOL contains 136 high-voltage bus-to-bus line segments. The input data for the *PowerWorld* model for generators, loads, lines, transformers, and the network are available on computer disk from EIA.[24]

This representation of NEPOOL accounts for 85 percent of FERC's reported load (20,178 megawatts) and 87 percent of its generation (18,696 megawatts). The model totals are less than on the FERC file because some of the demand and generation are netted out against each other in the aggregation process. Each bus connected to a high-voltage power line generates its own "tree" of lower voltage lines connecting smaller buses. When one of these trees contains both load and generation, they are combined. The remaining input data that need to be specified include the electricity the generators put onto the high-voltage lines and the electricity withdrawn from them.

As noted above, the economic portion of the model consists of marginal costs for each generator. The fuel cost part of the marginal cost curve, the *b* parameter, was estimated by multiplying each generator's heat rate (British thermal units per kilowatt) by its fuel cost (dollars per British thermal unit).[25] Each generator's heat rate and fuel cost were derived from FERC Form 1 filings for 1995, resulting in estimates for 53 of the 85 generators, representing about 74 percent of the generation capacity. Excluding a biomass plant and small oil-fired plants, the estimated fuel costs range between 4 and 33 mills per kilowatthour. Appendix Table A1 lists the estimated marginal costs of the generators. The curvature parameters in the model are based on analyst judgement.

PowerWorld also requires maximum and minimum limits for each generator's output. The capacity listed on FERC Form 715 was taken as the maximum operating level. Appendix Table A1 lists the operating limit data. If a lower limit was listed on FERC Form 715, it was taken to be the minimum operating limit. Otherwise, the minimum operating limit was taken as zero. Of the 53 generators on automatic generation control, 36 had operating limits strictly greater than zero. The sum of their minimal operating levels (5,243 megawatts) accounts for 26 percent of the total capacity (20,063 megawatts) listed on FERC Form 715.

As suggested earlier, *PowerWorld* dispatches only those generators for which estimated cost curves are available. It was assumed that the output of generators for which cost data are not available (3,015 megawatts) is committed regardless of price. The sum of the minimal operating levels plus the fixed output of those generators for which cost data are not available amounts to about 41 percent of NEPOOL's total capacity and is committed prior to the start of dispatch.

The current NEPOOL model consists of the high-voltage network, generator capacities, estimates of the marginal costs of about 74 percent of generator capacity, and two solution algorithms (power flow and optimal power flow). The marginal-cost estimates represent fuel costs. The optimal economic equilibrium has not been implemented because estimates of vocational demand curves are not available.

Data Quality and Model Results

The NEPOOL model described in this paper was built using FERC data on network characteristics (FERC Form 715) and generator costs (FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"). The coverage and quality of the data diminish as the level of aggregation decreases. It is also expected that, as more unregulated generators enter electricity markets, the coverage of the FERC cost data will decrease.

FERC Form 715 exhaustively lists the physical attributes of the network, and system maps developed by NEPOOL are usually adequate for locating generators. However, because of the general mismatch between the names in FERC Form 715 and the names on maps, there is ambiguity about the location of demand buses. One

[23]The two DC lines are represented as a single generator located at their junction with the NEPOOL grid. The imports were generally set to 1,500 megawatts, corresponding to the imports reported on FERC Form 715.

[24]The data can be obtained from James Hewlett (202-586-9536 or e-mail at jhewlett@eia.doe.gov).

[25]Variable operations and maintenance (O&M) costs may be added to the model at a later date.

cannot determine the location of some of the larger buses with certainty. FERC Form 715 does not report flows experienced at a point in time. Instead, the demand and generation reported on the form are estimates of summer peak. As a result, the power flows are calculated rather than measured values.

Data on heat rates and average annual costs of fuel are available on FERC Form 1 for investor-owned utility generators. The annual averages are estimates of the marginal fuel costs to generators at any particular time. Variable operations and maintenance costs can also be estimated from FERC Form 1, but these are not currently included in the model. Searches of secondary sources and an attempt to estimate the curvature parameters of the cost curves failed to improve the resolution of the cost estimates. The capacity of utility-owned generators is also available on FERC Form 715 and on Form EIA-860, “Electric Utility Generator Report,” although the values are not always the same.

There are no comparable cost data for generators owned by municipalities, cooperatives, cogenerators, or independent power producers, which amount to 26 percent of the NEPOOL generation capacity. It is assumed that these suppliers put all their generation reported on FERC Form 715 on the grid regardless of price. The impact of these generators on competitive prices could be out of proportion to their relatively small share of NEPOOL generation capacity. If they are the incremental sources of supply, then their marginal costs would determine the competitive price. The accuracy of the estimates of their marginal costs would determine how accurately competitive market prices could be forecast.

There are no adequate publicly available data for making realistic estimates of price-sensitive demand curves at major NEPOOL demand locations. To make such estimates would require information on the demand (loads) at the location and the concurrent price. As mentioned above, the FERC does not require measures of actual load at demand centers. Data are available for annual sales within regions and real-time price elasticities of demand. They are, however, based on limited information. This analysis assumes that demand (load) is fixed at the levels in NEPOOL’s FERC Form 715 filing.

The emergence of the ISO and competitive spot markets at major trading points may substantially improve the availability of data for estimating demand. The ISO will need to know the real-time deliveries of power at major nodes throughout the system. Spot markets at these locations would provide the corresponding prices. In the event that spot markets do not emerge, the ISO in some designs could calculate “pseudo” competitive prices corresponding to the loads.[26]

To check that the model approximates the actual network, it was solved with the configuration of generation and loads reported in the FERC Form 715 file. The historical configuration was a feasible solution for the network. The line flows were also close to those reported to the FERC. Except for two outliers, the distribution of percentage errors ranged from -2 percent to 13 percent. The average absolute percentage error across all lines was 1.3 percent. The outliers of 37 and 60 percent occurred on two small lines, the discrepancies amounting to less than 1.8 megawatts each.

Results

The starting point for the analysis of the three questions posed above is the “base case” that uses the 1995 summer peak loads, power plant, and transmission network data as reported on FERC Form 715. NEPOOL is heavily dependent on nuclear power, and in 1995 all seven of its nuclear units were in operation. In 1996, however, two of the older units—Connecticut Yankee and Maine Yankee—were permanently retired, and the three Millstone units were taken out of service because of safety concerns. Connecticut Yankee and the Millstone units, located in southern New England, provide 70 percent of the generation in that part of NEPOOL.

To gain some insights about the importance of reactive power and voltage control in assessing capacity, a “nuclear shutdown” case was run. In that case, the two Yankee and three Millstone units were taken out of service and replaced with equivalent amounts of capacity located in the northern part of NEPOOL.[27] The question is whether the transmission system has the capability to handle the flows of power from the northern to the southern part of NEPOOL. Because this case entails substantial changes in the regional distribution of generating capacity, the results provide an indication of the sensitivity of marginal-cost-based prices to changes in the spatial distribution of generation relative to loads. To examine the question of how network (and other) factors affect dispatching and marginal generation costs, a series of cases were run in which the 1995 peak loads were reduced. The details of those cases are described below.

Assessing Generation and Transmission Capability

Table 1 shows summary results for the base case. As noted above, because both real and “wattless” power

[26]See, for example, W. Hogan, “Contract Networks for Electric Power Transmission,” *Journal of Regulatory Economics*, Vol. 4 (1992), pp. 211-242.

[27]It was assumed that all the power was replaced with imports from Canada. The interconnection between Canada and the NEPOOL is located in northern New England. Similar results were obtained when the capacity of various fossil fuel units in northern New England was increased.

Table 1. 1995 Peak Load and Generation in the Base Case

Parameter	Real Power (Megawatts)	Reactive Power (Million Voltage-Amperes Reactive)	Apparent Power (Million Voltage-Amperes)
Load.	17,093.1	2,174	22,913
Generation	17,732.9	2,546	18,290
Losses	240.7	1,544	NA

NA = not applicable.

Notes: Shunts are not included. Thus, loads plus losses do not equal generation. The outflows of power to other regions are depicted as negative loads. If the negative loads were excluded, the total amount of real power and apparent power would be 18,125 and 20,629 megawatts, respectively. The power factor would be about 0.88 (18,125/20,629).

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

actually flow through power lines, the correct measure of the capacity of a transmission line is apparent power (i.e., MVA), which includes both real and reactive power. As Table 1 indicates, in the aggregate, the ratio of real to apparent power is 0.88 (18,125 / 20,629).[28] A DC model that ignores reactive power would, therefore, on average, understate the actual flows of power over the lines by about 15 percent. The ratio of real to apparent power is also called the "power factor." Utilities will typically not directly charge a customer for reactive power unless its power factor falls below 0.85. It is, therefore, not surprising to see an average power factor of 0.88.

The results of the nuclear shutdown case illustrate the importance of correctly accounting for voltage control and reactive power in assessing capability issues. In this case a few power lines were overloaded, and their capacity was consequently increased to handle the power flows. Even after removing the line constraints on the movements of power, however, it was still impossible to obtain a solution. The problem was with voltage control and reactive power. In particular, the voltage was not sufficient to meet the needs of about 70 percent of the loads, generators, and transformers in southern New England (21 of the 34 buses in Connecticut are part of the Northeast Utilities and United Illuminating service areas).

One way to control voltage is to alter the generation of reactive power. Because of line losses, reactive power must be produced relatively close to the loads. (As Table 1 shows, in the base case, the line losses for reactive power are over 50 percent.) All four nuclear units are located within 100 miles of the Hartford-New Haven area. Without these units, there were not sufficient supplies of reactive power in that area. As a result, the voltage collapsed in this simulation. This conclusion was confirmed by allowing the Millstone 1 unit to operate, which raised the marginal cost from 0.6 to 6 cents per kilowatthour. Because of the high assumed marginal cost, Millstone 1 did not produce any real power, although it did generate about 1,000 megaVAR of reactive power. This increase was sufficient to meet the needs for voltage support in that part of NEPOOL.

To summarize, if only real power were considered, it would appear that there was sufficient capacity to handle increased flows of power from the northern to the southern part of NEPOOL This conclusion would, however, be incorrect, because there was insufficient capacity in this case for reactive power used to control voltage.[29] This result suggests that the use of anything less than a full AC model could produce incorrect conclusions about transmission capability when major portions of generating capacity are removed from the system.

Marginal Costs of Generating and Transmitting Power

Figure 1 shows the distribution of short-run marginal costs of generating and transmitting electricity. This figure shows the number of load buses with marginal costs equal to or less than the amount shown on the *y*-axis. Costs for a selected number of cities in NEPOOL are shown in Table 2. All the costs were derived from the base case as described above. As noted above, actual market prices would be expected to be higher than these costs, because they do not include charges to recover fixed transmission costs. Such charges would be needed

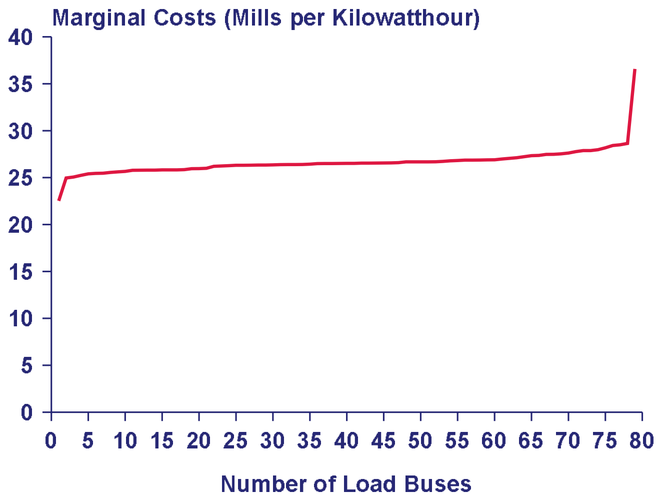
[28]The data shown in Table 1 include loads with negative amounts of real power. Using these data, the power factor would be about 0.75. The power factor cited here (0.88) excludes the negative loads. When the loads with negative amounts of real power are excluded, the total amount of real power increases from 17,093 to 18,125 megawatts. Apparent power equals the square root of the squared amount of real and reactive power. Thus, when all the loads with negative amounts of real power are excluded, the total amount of apparent power decreases from 22,913 to 20,629 megawatts.

[29]Some initial analysis of the 1997 FERC Form 715 data suggests that the short-term replacement capacity was obtained from old "mothballed" units and cogeneration facilities located in southern New England. Voltage control was probably one reason why that was done. Additionally, Commonwealth Edison recently announced the retirement of Zion (two 1,100-megawatt nuclear power units in Illinois). There is some discussion about using one of the "retired" units to produce reactive power for voltage control.

to ensure that the transmission system would be economically viable.[30]

At least at the level of aggregation used in this analysis, the results shown in Figure 1 suggest that the short-run marginal cost pricing of generation and transmission would result in relatively small locational variations in electricity prices. That is, excluding two outliers, the maximum difference in locational costs is about 3 to 4 mills per kilowatthour. Moreover, marginal generation costs for NEPOOL were about 2.6 cents per kilowatthour, and most of the costs shown in Figure 1 are within 2 to 3 mills per kilowatthour of that amount, suggesting that short-run marginal transmission costs are relatively small.[31]

Figure 1. Cumulative Distribution of Short-Run Marginal Generating and Transmission Costs in the Base Case



Notes: The figure shows the number of load buses with marginal costs less than or equal to the amounts shown on the *y*-axis. The data do not include charges to recover fixed transmission and distribution costs, which would be needed to ensure the financial viability of the transmission and distribution systems.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Short-run marginal transmission costs are influenced by the amount of congestion (i.e., line overloads) and the value of the marginal line losses. In the base case, at the level of aggregation used, there were no line overloads and, therefore, no congestion. Additionally, in most cases, marginal line losses were about 4 to 5 percent. That is, at most buses, about 1.04 kilowatthours of electricity is generated to satisfy the last kilowatthour of electricity demand.[32] It was, therefore, not surprising that the regional variations in costs were small and short-run marginal transmission costs were small.

The high-voltage transmission system in NEPOOL was, in part, designed to minimize congestion and equalize line losses across the system. The design of the transmission system also assumed, however, that substantial amounts of baseload generating capacity would be located in southern New England. (As of 1995, Connecticut Yankee and the three Millstone units provided that capacity.) The nuclear shutdown case offers an interesting "case study" on what would happen if the bulk of the generating capacity in the southern part of NEPOOL were shifted to the northern part of the region.[33] That is, this case provides insights about how substantial changes in the regional distribution of generating capacity affect costs when the distribution of loads is held constant.

Table 2. Short-run Marginal Generation and Transmission Costs for Selected Cities in Two Cases
(Mills per Kilowatthour)

City	Base Case	Nuclear Shutdown Case
Portland, ME	25.4	26.5
Boston, MA	25.6	26.2
Providence, RI	26.4	27.5
New Haven, CT	27.5	33.6
Hartford, CT	26.9	32.8
Springfield, MA	26.3	26.7

Note: These data do not include any charge to recover the fixed transmission and distribution costs. Such a charge would be needed to ensure the financial viability of the transmission and distribution sectors.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[30]Additionally, since these are short-run marginal costs, they do not include some generating costs that are fixed in the very short run but are variable over longer periods of time. Examples of such costs include variable nonfuel operating and maintenance costs and some overhead expenses. See Energy Information Administration, *Electricity Prices in a Competitive Environment*, DOE/EIA-0614 (Washington, DC, August 1977), Chapter 3.

[31]The two outliers appear to be the result of errors in the FERC Form 715 data. *PowerWorld* computes the marginal generation costs by "backing out" the line losses. The marginal line losses can be negative when a small increase in demand at one bus causes network-wide changes in generation and line flows that in turn result in fewer line losses. See F.C. Schweppe et al., *op. cit.*, for more details.

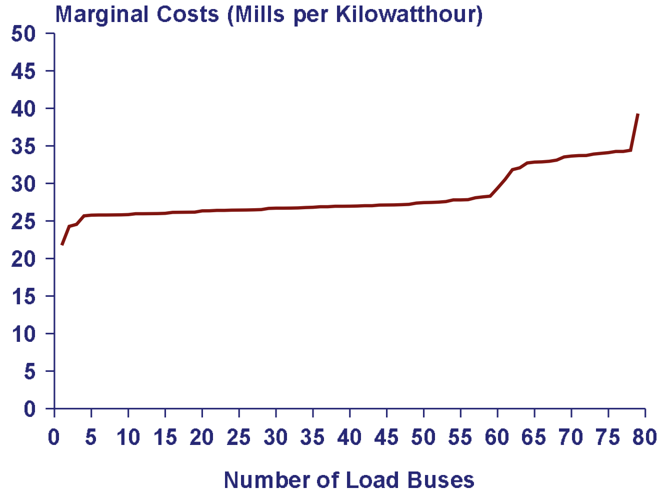
[32]Note that the estimated marginal line losses are only slightly greater (in absolute terms) than the average line losses of about 1.5 percent (see Table 1).

[33]Connecticut Yankee was permanently retired in 1996.

The distributions of short-run marginal generation and transmission costs in the nuclear shutdown case for NEPOOL as a whole and for selected cities are shown in Figure 2 and Table 2, respectively. These results suggest that a substantial shift in the regional distribution of generation, holding the distribution of loads and the structure of the transmission system constant, would have a modest impact on the distribution of prices based on short-run marginal generating and transmission costs. In the nuclear shutdown case, the maximum difference is about 7 to 8 mills per kilowatthour. In the New Haven and Hartford areas (i.e., southern New England), costs are only about 6 mills per kilowatthour (about 20 percent) higher than those in the base case. Although there still are no line overloads in the nuclear shutdown case, there are substantial increases of power flows from the north to the south. As a result, marginal line losses in the south increase to about 20 percent. Marginal generation costs in that area are about 30 mills per kilowatthour, and the value of the 20-percent increase in lost power is therefore about 6 mills per kilowatthour.

To summarize, at the level of aggregation used in this analysis, it would take extreme changes in the regional distribution of generation to produce modest variations in location-specific prices. It is unclear whether the changes in behavior caused by such modest changes in costs would be sufficient to outweigh the ISO's administrative and computation costs. Moreover, prices would actually be higher than those estimated here, because some charge would be required to recover fixed transmission costs, which could vary by location.

Figure 2. Cumulative Distribution of Short-Run Marginal Generating and Transmission Costs in the Nuclear Shutdown Case



Notes: The figure shows the number of load buses with marginal costs less than or equal to the amounts shown on the *y*-axis. The data do not include charges to recover fixed transmission and distribution costs, which would be needed to ensure the financial viability of the transmission and distribution systems.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Interaction Between Transmission and Power Plant Operations

The *PowerWorld* model chooses the dispatching pattern that minimizes variable generation costs, subject to a series of voltage, transmission, and unit-specific operational constraints. It is, therefore, possible to compare this dispatching pattern with one that ignores the constraints and simply dispatches plants on the basis of marginal costs. Such comparisons yield some insights about the frequency of out-of-order dispatching and its effects on fuel consumption and marginal generation costs.

In the base case, given the lack of excess capacity, the overall constraint stating that generation must equal demand should override network and operational constraints.[34] That is, to supply enough power to meet peak load, almost all units must operate at full capacity regardless of cost. However, the network and other constraints should become more important in the off-peak periods when there are relatively large amounts of excess capacity. To study how these constraints affect dispatching of power plants in off-peak periods, two reduced demand cases were run, with the peak demand at each load bus reduced by 15 and 30 percent, respectively. In the absence of any network or operational constraints, the 15 and 30 percent of the capacity with the highest marginal costs would not operate in the 15 and 30 percent demand reduction cases, respectively. If, however, binding constraints arose, some relatively high-cost units would operate. That is, such units would be operated "out of order."

Tables 3, 4, and 5 show the units that are dispatched out of order, in the base and the two reduced demand cases. Using pure economic dispatch results in no generation for the units. The column, "constrained economic dispatch" shows the level of generation based on cost minimization subject to all the constraints in the *PowerWorld* model. As expected, at the peak period, virtually all units must operate to meet demand; therefore, only a few units are operated out of order (Table 3). In the two reduced demand cases, however, the number of plants operated out of order increases substantially (Tables 4 and 5). These results suggest that out-of-order dispatching in off-peak periods can be substantial.

Also shown in Tables 3, 4, and 5 are the minimum generation levels reported on FERC Form 715. These values were used as the minimum generation constraints in *PowerWorld*. A comparison of the level of generation from the units dispatched out of order with the minimum generation levels gives some indication of whether

[34]Actually, in *PowerWorld*, there is no overall constraint stating that generation must equal demand. Instead, there are a series of constraints stating that at every bus the sum of inflows of power and generation must equal the sum of the outflows plus consumption.

Table 3. Units Dispatched Out of Order in the Base Case

Plant Name	Marginal Cost (Mills per Kilowatthour)	Pure Economic Dispatch (Megawatts)	Constrained Economic Dispatch (Megawatts)	Fuel	Minimum Generation (Megawatts)	Capacity (Megawatts)
West Springfield . . .	26.0	0	107.05	NG	20	107
Canal 2	26.1	0	143.63	Oil	0	576
Norwalk Harbor 1 . . .	28.6	0	39.97	Oil	40	162
Norwalk Harbor 2 . . .	28.6	0	39.97	Oil	40	168
Middletown 3	30.7	0	94.84	Oil	95	233
Cleary Flood	32.5	0	34.73	Oil	35	85
Montville 5	32.6	0	20.70	Oil	21	81

NG = natural gas.

Note: The cost data reported on FERC Form 1 are at the plant level, and the FERC Form 715 data are at the unit level. Whenever the Form 1 data indicated the use of oil and natural gas, it was assumed that all units used natural gas.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 4. Units Dispatched Out of Order in the 15 Percent Demand Reduction Case

Plant Name	Marginal Cost (Mills per Kilowatthour)	Pure Economic Dispatch (Megawatts)	Constrained Economic Dispatch (Megawatts)	Fuel	Minimum Generation (Megawatts)	Capacity (Megawatts)
New Boston 1	24.2	0	99.67	NG	100	205
New Boston 1	24.2	0	85.07	NG	85	175
New Boston 3	24.2	0	184.86	NG	185	380
Salem Harbor 1	25.9	0	34.78	Coal	35	79
Salem Harbor 2	25.9	0	34.78	Coal	35	78
Salem Harbor 3	25.9	0	59.77	Coal	60	143
Salem Harbor 4	25.9	0	99.77	Coal	100	400
West Springfield . . .	26.0	0	19.79	NG	20	107
Norwalk Harbor 1 . . .	28.6	0	39.67	Oil	40	162
Norwalk Harbor 2 . . .	28.6	0	39.67	Oil	40	168
Middletown 3	30.7	0	94.55	Oil	95	233
Cleary Flood	32.5	0	34.47	Oil	35	85
Montville 5	32.6	0	20.42	Oil	21	81

NG = natural gas.

Note: The cost data reported on FERC Form 1 are at the plant level, and the FERC Form 715 data are at the unit level. Whenever the Form 1 data indicated the use of oil and natural gas, it was assumed that all units used natural gas.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

network constraints or operational constraints (i.e., minimum generation level) are binding. If a unit that otherwise would not be dispatched is operating at its minimum level, then it would appear that the minimum operating constraint, as opposed to the network constraint is binding. This is important because the minimum operating constraints are in some sense exogenous data inputs, whereas the other constraints are more in the nature of endogenous model outputs.

For example, in the base case, in the absence of any constraints, the Canal G2 oil-fired power plant should not operate because its marginal costs are too high. When all the constraints are considered, however, the cost-minimizing solution is to generate about 104 megawatts of real power from that unit. Because the optimal level of generation for Canal G2 is far above its minimal level, it would appear that the network constraints are binding. (Such a plant is often called a "must run" unit, because its operation is based on transmission or voltage factors.) The Middletown 3 unit is also dispatched out of order. Because the optimal level of generation of that unit is at the minimum level, it would appear that the minimum output constraint is binding.

In the base case, only two units are dispatched out of order as a result of binding network constraints, In the two reduced demand cases, all the out-of-order dispatching appears to be the result of the minimum output level, as opposed to network constraints. This result is noteworthy because these minimum output levels, reported on FERC Form 715, are data inputs and, at this point, are subject to two interpretations.

Table 5. Units Dispatched Out of Order in the 30 Percent Demand Reduction Case

Plant Name	Marginal Cost (Mills per Kilowatthour)	Pure Economic Dispatch (Megawatts)	Constrained Economic Dispatch (Megawatts)	Fuel	Minimum Generation (Megawatts)	Capacity (Megawatts)
Brayton Point 6	20.6	0	99.36	Coal/NG	100	421
Brayton Point 1	20.6	0	63.17	Coal/NG	64	140
Brayton Point 1	20.6	0	45.57	Coal/NG	46	101
Brayton Point 1	20.6	0	63.17	Coal/NG	64	140
Brayton Point 1	20.6	0	45.57	Coal/NG	46	101
Mystic	22.0	0	99.29	Coal/NG	100	565
Somerset	22.2	0	34.31	NG	35	105
Potter Station 1	23.0	0	19.27	NG	20	76
Potter Station 1	23.0	0	3.27	NG	4	13
New Haven Harbor . .	23.3	0	119.24	NG	120	447
New Boston 1	24.2	0	98.99	NG	100	205
New Boston 1	24.2	0	84.39	NG	85	175
New Boston 3	24.2	0	184.18	NG	185	380
Salem Harbor 1	25.9	0	34.11	Coal	35	79
Salem Harbor 2	25.9	0	34.11	Coal	35	78
Salem Harbor 3	25.9	0	59.10	Coal	60	143
Salem Harbor 4	25.9	0	99.10	Coal	100	400
West Springfield . . .	26.0	0	19.11	NG	20	107
Norwalk Harbor 1 . . .	28.6	0	38.98	Oil	40	162
Norwalk Harbor 2 . . .	28.6	0	38.98	Oil	40	168
Middletown 3	30.7	0	93.87	Oil	95	233
Cleary Flood	32.5	0	33.79	Oil	35	85
Montville 5	32.6	0	19.77	Oil	21	81

NG = natural gas.

Note: The cost data reported on FERC Form 1 are at the plant level, and the FERC Form 715 data are at the unit level. Whenever the Form 1 data indicated the use of oil and natural gas, it was assumed that all units used natural gas.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

In particular, for some units it is prohibitively expense to cease operation and then restart the power plant. (A good example of this is a nuclear power plant.) In such cases, the minimum generation levels are dictated by engineering considerations. For other units, however, the startup costs are substantial but not prohibitively expensive. In these cases, the minimum generation levels reported by the utility could be the result of an implicit (or explicit) cost-benefit analysis. Stated somewhat differently, it is possible that the minimum generation levels could be based more on economics than on engineering considerations. In the present analysis, the minimum generation levels are used as fixed constraints, an approach that is valid only if they are dictated largely by engineering, as opposed to economic, considerations.

Although the network and operational constraints do affect off-peak dispatching patterns substantially, there is some evidence that, in the aggregate, the effects on fuel usage may be relatively minor. Table 6 shows capacity dispatched by fuel type based on pure and constrained merit-order dispatching in the base case and the two reduced demand cases. When the network and operational constraints are binding, the effect is to increase generation from relatively high-cost units. Since demand would not be affected by these constraints, the increased generation must be offset by reduced generation from lower cost units.[35] As Table 6 shows, the effect of binding network and operational constraints is to increase generation from oil-fired units. In the 15 percent reduction case, such increases are offset by decreases from gas-fired units. Since many of these gas-fired units are not dispatched in the 30 percent reduction case (Table 5), the increases are offset by decreased generation from nuclear power plants.[36] In all cases, the effects are relatively small—generally, less than 1 gigawatt.

[35] The cost data reported on FERC Form 1 are generally available only at the plant level. In a number of cases, units at the same site use different fuels. When the FERC Form 1 data showed the use of oil and natural gas, it was assumed that all units used natural gas.

[36] In reality, nuclear units generally are not cycled. They are, however, taken out of service for refueling during off-peak periods.

Table 6. Estimated Capacity Use by Fuel Type, Based on Pure and Constrained Economic Dispatch, in Three Cases
(Gigawatts)

Fuel	Base Case		15 Percent Demand Reduction		30 Percent Demand Reduction	
	Pure Economic Dispatch	Constrained Economic Dispatch	Pure Economic Dispatch	Constrained Economic Dispatch	Pure Economic Dispatch	Constrained Economic Dispatch
Nuclear	6.45	6.46	6.45	6.46	6.45	5.72
Coal	1.49	1.40	0.84	1.07	0.84	0.70
NG	5.08	5.03	4.24	3.29	1.65	1.80
Oil	1.14	1.22	0.06	0.68	0.06	0.67
Other/Unknown	2.07	2.12	2.07	2.17	2.07	2.17
Total[a]	**16.23**	**16.23**	**13.66**	**13.67**	**11.07**	**11.06**

[a]Imports not included.
NG = natural gas.
Note: The cost data reported on FERC Form 1 are at the plant level, and the FERC Form 715 data are at the unit level. Whenever the Form 1 data indicated the use of oil and natural gas, it was assumed that all units used natural gas.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The effects of the network and operational constraints on marginal generation costs are much more pronounced (see Table 7). When these constraints become binding, they tend to constrain the operation of relatively high-cost units. Since the operation of such units is "fixed," the last or marginal kilowatthour of real power must be obtained from units lower in the merit order. When these constraints become binding, the effect is to cause system-wide marginal generation costs to be lower than otherwise would be the case. In the base case, the effects are small; however, in the two reduced demand cases, the effects become larger. It must be stressed that in the two reduced demand cases, the minimum generation level constraint is always binding. As noted above, it is valid to use these minimum generation levels as exogenous constraints only if they are largely based on engineering as opposed to economic considerations.

Conclusions

This paper presents some initial results of an ongoing project. Although the model of NEPOOL used here is highly aggregated and a few data problems remain, a number of points are worth making. First, it appears that transmission capacity issues can be examined adequately only with a full AC model of the transmission network. The nuclear shutdown case was designed so that the line capacity was sufficient to avoid any line overloads. Nevertheless, in this hypothetical scenario, the system was not capable of meeting demand because the voltage was not sufficient. This, in turn, was caused by a lack of capacity for reactive power. A DC model would consider only the flow of real power, ignoring reactive power. Thus, a voltage collapse caused by a lack of reactive power can only be detected with a full AC model. Moreover, the FERC Form 715 data suggest that the flows of reactive power are substantial and, therefore, can not be ignored. For example, if reactive power is ignored, the FERC data suggest that, on average, the actual flows over power lines would be understated by about 15 percent.

Second, at least at the level of aggregation used in this analysis, the issue of the locational pricing of real power appears to be of secondary importance. Even in an extreme case, the maximum variation in marginal costs was only about one-half of a cent. This analysis did not, however, examine issues dealing with the pricing of ancillary services such as voltage control and reactive power. The results of the nuclear shutdown case suggest that these factors can be important, and that attention should be paid to how these services will be priced.

Table 7. Estimated Marginal Generation Costs, Based on Pure and Constrained Economic Dispatch, in Three Cases
(Mills per Kilowatthour)

Case	Pure Economic Dispatch	Constrained Economic Dispatch
Base	26.1	25.8
15 Percent Demand Reduction	24.2	20.7
30 Percent Demand Reduction	20.6	7.9

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Third, the reduced demand cases suggest that out-of-order dispatching could have substantial effects on estimates of marginal generation costs. At least according to the conventional wisdom, much of the out-of-order dispatching occurs because of very localized network factors (e.g., localized transmission constraints or voltage control problems over a fairly small area). Many of these factors were probably “lost” in the process of aggregating a 2,000-bus system to a 150-bus representation. At this level of aggregation, the minimum generation level, as opposed to network constraints, was binding. This point is noteworthy because it is not clear how the minimum generation levels reported on FERC Form 715 should be interpreted.

These results suggest that a more disaggregated version of NEPOOL should be used to determine whether network constraints actually cause most of the out-of-order dispatching. If this is the case, then the electricity dispatching algorithm in NEMS should be enhanced to include this feature. If the minimum generation constraints are still binding, then the FERC Form 715 data should be more closely examined. One way of doing this would be to compare the data with EIA’s monthly generation information. If the minimum operating level data from FERC Form 715 are “real,” then the cost data used in the NEMS electricity generation algorithm should be modified.

In addition, to study whether the transmission network can handle large flows of power from one NERC region to another (e.g., flows of power generated by inexpensive coal-fired power plants in eastern Ohio to Boston), two or three NERC regions could be linked, so that the effects of hypothetical trades across NERC regions could be simulated. With existing PC-based software able to handle 10,000 to 15,000 bus networks, the amount of aggregation required for the analysis of linked NERC regions should be minimal.

Appendix A
Generator Data

Table A1. Generator Data Used in the Analysis

Plant Name	Marginal Costs (Mills per Kilowatthour)	Fuel	Output of Real Power		Output of Reactive Power	
			Minimum	Maximum	Minimum	Maximum
Colfax 1	NA	NA	0	48	-12	19
Colfax 1	NA	NA	0	27	-7	11
CRRRA	NA	NA	0	57	-36	30
Enron 2	NA	NA	74	109	-36	53
Madison 1	NA	NA	0	106	-16	55
Madison 2	NA	NA	0	106	-16	55
Madison 3	NA	NA	0	95	-33	52
Dartmouth Power 1 . . .	NA	Oil	0	47	-7	17
Dartmouth Power 1 . . .	NA	Oil	0	21	-3	8
High Street Station 1 . .	NA	NG	0	38	4	4
High Street Station 1 . .	NA	NG	0	42	10	10
AES Thames	NA	Coal	60	180	0	80
Altresco 1	NA	NG	0	33	0	13
Altresco 1	NA	NG	0	33	0	13
Altresco 3	NA	NG	0	33	0	13
Altresco 3	NA	NG	0	49	0	20
Blackstone	NA	NA	0	70	-25	47
Bellingham 1.	NA	NG	34	82	0	40
Bellingham 1.	NA	NA	34	82	0	40
Bellingham 3.	NA	NA	47	113	0	55
Obrien 1	NA	NA	0	20	-12	14
Obrien 1	NA	NA	0	20	-12	14
Obrien 1	NA	NA	0	14	0	1
Rumford C	NA	Coal	0	112	0	50
SEMASS Re	NA	NA	0	70	-5	25
Bear Swamp 1.	0.00	WAT-PP	-300	282	0	130
Bear Swamp 2.	0.00	WAT-PP	-300	282	0	130
Northfield Mountain 1 . .	0.00	WAT	-250	270	-52	100
Northfield Mountain 1 . .	0.00	WAT	-250	270	-52	100
Northfield Mountain 3 . .	0.00	WAT	-250	270	-52	100
Northfield Mountain 3 . .	0.00	WAT	-250	270	-52	100
Vermont Yankee.	4.17	Nuclear	0	496	-100	150
Pilgrim	4.49	Nuclear	402	670	-100	340
Maine Yankee	5.13	Nuclear	0	910	0	220
Haddam Neck	5.21	Nuclear	339	565	-95	290
Millstone 3	5.26	Nuclear	682	1,146	0	550
Seabrook	5.76	Nuclear	690	1,150	-100	590
Millstone 1	7.10	Nuclear	391	652	-50	275
Millstone 2	7.10	Nuclear	518	862	-60	470
Stony Brook 1	15.43	NG	0	86	-9	70
Merrimack 1	16.91	Coal	30	113	-10	53
Merrimack 2	16.91	Coal	120	320	-30	150
Stony Brook 1	17.26	NG	0	65	-8	59
Stony Brook 1	17.26	NG	0	65	-8	59
Mount Tom	18.29	Coal	60	146	-24	30

See notes at end of table.

Table A1. Generator Data Used in the Analysis (Continued)

Plant Name	Marginal Costs (Mills per Kilowatthour)	Fuel	Output of Real Power		Output of Reactive Power	
			Minimum	Maximum	Minimum	Maximum
Ocean Station 1	19.06	NG	0	77	0	38
Ocean Station 2	19.06	NG	0	77	0	38
Ocean Station 3	19.06	NG	0	108	0	52
Ocean Station 4	19.06	NG	0	77	0	38
Ocean Station 5	19.06	NG	0	77	0	38
Ocean Station 6	19.06	NG	0	108	0	52
Bridgeport Harbor 1 . . .	19.55	NG	34	170	-17	115
Bridgeport Harbor 2 . . .	19.55	NG	130	375	-35	220
Brayton Point 5	20.59	Coal/NG	350	585	-140	275
Brayton Point 6	20.59	Coal/NG	100	421	-45	250
Brayton Point 1	20.59	Coal/NG	64	140	-23	64
Brayton Point 1	20.59	Coal/NG	46	101	-16	47
Brayton Point 1	20.59	Coal/NG	64	140	-20	64
Brayton Point 1	20.59	Coal/NG	46	101	-15	47
Mystic	22.04	NG	100	565	-150	335
Somerset	22.20	NG	35	105	0	86
Potter Station 1	23.02	NG	20	76	-10	40
Potter Station 1	23.02	NG	4	13	0	2
New Haven Harbor . . .	23.30	NG	120	447	0	175
New Boston 1	24.17	NG	100	205	-26	119
New Boston 1	24.17	NG	85	175	-22	101
New Boston 3	24.17	NG	185	380	-50	230
Canal 1	25.53	Oil	0	566	0	239
Salem Harbor 1	25.87	Coal	35	79	-24	20
Salem Harbor 2	25.87	Coal	35	78	-14	38
Salem Harbor 3	25.87	Coal	60	143	-36	38
Salem Harbor 4	25.87	Coal	100	400	-160	280
West Springfield	26.01	NG	20	107	-37	52
Canal 2	26.11	Oil	0	576	-50	120
William F. Wyman	27.22	Oil	0	615	-215	267
Norwalk Harbor 1	28.64	Oil	40	162	-13	80
Norwalk Harbor 2	28.64	Oil	40	168	-12	60
Middletown 3	30.68	Oil	95	233	-28	90
Cleary Flood	32.52	NG	35	85	0	52
Montville 5	32.63	Oil	21	81	0	40
Stony Brook 1	45.79	Oil	0	65	-8	59
Stony Brook 1	45.79	Oil	0	65	-10	20
Stony Brook 1	45.79	Oil	0	65	-10	20
J.C. McNeil 1	74.21	Wood	0	47	-9	9
J.C. McNeil 1	74.21	Wood	0	11	0	0

NA = not available. NG = natural gas. WAT = hydroelectric. WAT-PP = hydroelectric pumped storage.

Note: The cost data reported on FERC Form 1 are at the plant level, and the FERC Form 715 data are at the unit level. Whenever the Form 1 data indicated the use of oil and natural gas, it was assumed that all units used natural gas.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Modeling Technological Change and Diffusion in the Buildings Sector

by
Andy S. Kydes and Steven H. Wade

This paper gives an overview of the way in which technological change and market diffusion are represented in the buildings sector (residential and commercial energy demand sectors) of the National Energy Modeling System (NEMS). The treatment of market diffusion in the buildings sector is illustrated by sensitivity cases that highlight how important parameters, such as energy prices, influence technology choice and change. The development and introduction of new technologies, their relative costs and performance, the physical lifetimes of installed equipment (which influence turnover rates), relative fuel prices, and consumer preferences are key factors that determine market diffusion rates for new technologies. Those rates in turn determine how quickly energy use patterns, energy efficiency, and energy-related environmental emissions can change.

Introduction

In 1990, the Secretary of Energy directed the Energy Information Administration (EIA) to develop the National Energy Modeling System (NEMS), based on recommendations from the National Research Council (NRC) of the National Academy of Sciences.[1] Key features implemented in NEMS include: (a) regional outputs of energy, economic, and environmental activity of the U.S. economy; (b) use of a modular modeling structure to facilitate and enable the model builders to work with particular aspects of the model independently; (c) integration of engineering and economic approaches to represent actual producer and consumer behavior; (d) use of a mid-term projection period spanning 20 to 25 years; (e) involvement of the broader energy analysis community and outside peer groups in the design and update of NEMS. Figure 1 illustrates the modular construction of NEMS and the basic information flows between modules during the solution process.

NEMS was completed at the end of 1993 and was first used to develop the *Annual Energy Outlook 1994*.[2] More recently, NEMS has been extended to 2020 and further revised to address electricity restructuring and carbon mitigation issues.[3]

The primary purpose of NEMS is to analyze the effects of energy policies and other pertinent influences on U.S. energy markets.[4] Important market influences include, for example, the magnitude of economically recoverable fossil fuel resources, characteristics of the world market for energy and their effects on oil prices, and the rate of development and penetration of new energy related technologies—as well as existing or prospective government policies and actions.

Current and emerging policy questions determine the level of detail required within the structure of NEMS. For example, energy-related environmental issues have taken on a new importance as a consequence of new NO_x and particulate emission regulations issued by the U.S. Environmental Protection Agency and both the Rio Treaty and the Kyoto Protocol on greenhouse gases. In the case of carbon (or carbon dioxide), NEMS constrains national carbon emissions using price. The NEMS electricity sector is designed to measure five emissions (oxides of sulfur, oxides of nitrogen, carbon, carbon monoxide, and carbon dioxide) released in the use of energy products to generate electricity. While NEMS is designed to constrain national carbon emissions using a pricing mechanism, sulfur dioxide constraints are imposed only in the electricity generation market.

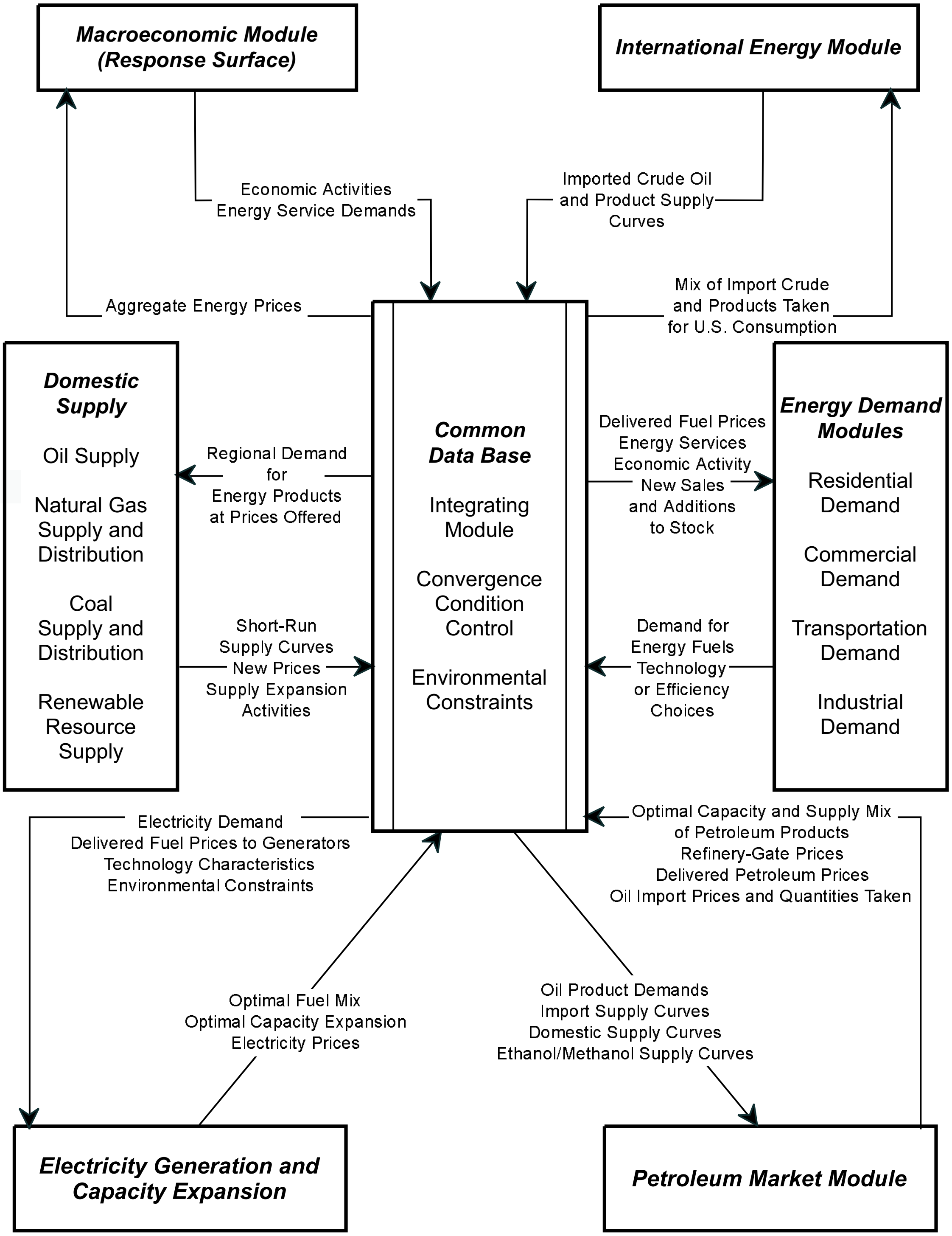
[1]National Research Council, Commission on Engineering and Technical Systems, Energy Engineering Board, Committee on the National Energy Modeling System, *The National Energy Modeling System* (Washington, DC: National Academy Press, 1992).

[2]Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994).

[3]Energy Information Administration, *Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities*, DOE/EIA-0614 (Washington, DC, August 1997); *An Analysis of Carbon Mitigation Cases*, SR-OIAF(96-01) (Washington, DC, June 1996); and *Analysis of Carbon Stabilization Cases*, SR-OIAF/97-01 (Washington, DC, October 1997).

[4]A.S. Kydes and S.H. Shaw, "The National Energy Modelling System: Policy Analysis and Forecasting at the U.S. Department of Energy," in *Systems Modelling for Energy Policy*, eds. D.W. Bunn and E.R. Larsen (New York, NY: John Wiley and Sons, 1997), pp. 9-30.

Figure 1. National Energy Modeling System



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The technology representation in NEMS explicitly represents vintaged (time-dependent) energy equipment and structures (e.g., building shells) and tracks vintaged capital stock turnover; thus, NEMS is particularly useful for analyses of carbon mitigation policies. For similar reasons, NEMS contains sufficient detail in the transportation sector to project the use of reformulated fuels or alternative fuels. In addition to environmental concerns, NEMS is designed to account for existing and emerging government policies (e.g., electricity restructuring and renewable portfolio standards). The potential for the development and use of new energy-related technologies, increased use of renewable sources of energy (especially intermittent technologies), and increases in the efficiency of energy use are other features that have been incorporated in NEMS, reflecting the expected scope of present and future analytical activities.

NEMS also allows for different market structures. For example, the *Annual Energy Outlook 1998* (*AEO98*) models California, New York, and New England as competitive electricity generation markets with marginal-cost pricing. The remainder of the U.S. electricity market is modeled with cost-of-service regulation and average-cost pricing.[5]

The representation of energy markets in NEMS focuses on four important interrelationships: (1) interactions among the energy supply, conversion, and consumption sectors, (2) interactions between the domestic energy system and the general domestic economy, (3) interactions between the U.S. energy system and world energy markets, and (4) the interaction between current production and consumption decisions and expectations about the future.[6]

Domestic Energy Supply, Conversion, and Consumption

Interactions among domestic energy supply, conversion, and consumption are assured through the representation of simultaneous competitive markets in achieving year-to-year energy-economy equilibrium subject to the equipment constraints imposed by a "bottom-up" approach. This approach begins by modeling the agents at a relatively disaggregated level (e.g., households by housing type and Census division) to determine from their decision rules the relative number of new home and equipment purchases for each housing type. The modeled decisions at the household level are summed to build higher levels of aggregation. The prices paid and quantities demanded for each fuel are balanced with the supply and prices offered through an iterative convergence process between supply and demand.

Domestic Energy-Economy Interactions

The general level of economic activity in sectoral and regional detail has traditionally been used as an explanatory variable or "driver" for projections of energy consumption and prices. In reality, energy prices and other energy system activities themselves influence the level of economic activity. NEMS is designed to capture feedback between the domestic economy and the energy system. The macroeconomic component of NEMS is a reduced form of the DRI macroeconomic model.[7] Changes in energy prices from a DRI reference case cause changes to macroeconomic variables such as disposable income, new car sales, and industrial output. In turn, changes in the macroeconomy cause changes to energy service demands.

Domestic and World Oil Markets

The world oil price (WOP) is a key variable in domestic energy supply and demand decisionmaking. As a result, WOP assumptions have been a key starting point in the development of energy system projections. In fact, the U.S. energy system itself exerts a significant influence on world oil markets, which in turn influence the WOP (another example of a feedback effect). World energy market supply and demand are first specified outside NEMS by a world oil model. NEMS then models the interactions between the U.S. and world oil markets through the use of import crude and product supply curves. Changes in U.S. oil markets affect world supply and demand. As a result, domestic energy system projections and the WOP are made internally consistent.

Economic Decisionmaking Over Time

Production and consumption of energy products today are influenced by past decisions to develop energy resources and acquire energy-using capital equipment. Similarly, the production and consumption of energy in a future time are influenced by decisions made today and in the past. Current investment decisions depend on expectations about future market circumstances. For example, the propensity to invest now to develop alternative energy sources increases when future energy prices are expected to increase. Recognizing that the formation of and response to price expectations in the residential and commercial energy markets differ from those in the electricity generation and industrial sectors, NEMS allows the differential application of foresight assumptions to its individual submodules. This flexibility allows the consequences of different planning horizons and consumer preferences to be incorporated in the NEMS projections.

The Residential Demand Module

The NEMS Residential Demand Module (RDM) is a "structural" model of energy demand. That is, its forecasts are built up from underlying projections of demographic variables, the residential housing stock, and the energy-consuming equipment contained in the housing stock. The RDM forecasts energy consumption by Census division for seven marketed energy sources (electricity, natural gas, distillate oil, liquid petroleum gas, kerosene, coal, and wood) plus solar thermal and geothermal energy. For each of the nine Census divisions,

[5]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

[6]Energy Information Administration, *The National Energy Modeling System: An Overview 1998*, DOE/EIA-0581(98) (Washington, DC, February 1998).

[7]The DRI macroeconomic model is a Keynesian model of the U.S. economy, which is characterized by a system of estimated nonlinear equations.

three housing types are modeled: single family, multifamily, and mobile homes. Within each housing type, 14 end uses are modeled: space heating, space cooling, water heating, refrigeration, cooking, clothes dryers, freezers, clothes washers, dishwashers, lighting, color televisions, personal computers, furnace fans, and other uses. Of the 14 end uses, the first 10 listed are modeled with underlying technology detail. The remaining end uses are modeled on the basis of trends in energy consumption.

In developing energy consumption projections, the RDM incorporates projections of the effects of four broadly defined determinants: economic and demographic effects, structural effects, technology effects, and energy market effects. Economic and demographic effects include housing starts, population, the number of persons per household, dwelling type (single-family, multifamily, or mobile homes) and location of housing units. Structural effects include changes in the average dwelling size and changes in the mix of desired end-use services provided by energy (new end uses and/or increasing penetration of current end uses, such as the increasing popularity of electronic equipment and computers). Technology effects include changes in the stock of installed equipment caused by normal turnover and replacement of old, worn-out equipment with newer versions (which often are more energy efficient), the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of even more energy-efficient equipment in the future. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment and the efficiency of building shells, and limitations on minimum levels of efficiency for new purchases of energy-consuming equipment imposed by Federal efficiency standards.

Data Sources

The RDM is initialized with data characterizing housing and appliance stocks for its base year, currently 1993. The RDM relies on EIA's Residential Energy Consumption Survey (RECS) for a large part of this initial information.[8] RECS is a nationally representative, stratified sample based on a detailed survey of more than 6,000 households. RECS housing characteristics are derived directly from the survey data. Since no appliance-level metering of energy is performed for the RECS, its end-use consumption data are derived from a statistical analysis of monthly energy bills for the surveyed households. The 1993 edition of RECS is the latest available[9] and was used for the *AEO98*. From RECS, the RDM obtains estimates by Census division for the following:

- Housing stock—number and dwelling type
- Average dwelling sizes in square feet (stock average and new construction)
- General characterizations of equipment stocks (i.e., number and type of energy-consuming equipment, but not efficiency)
- Number of occupants
- Estimated energy consumption by appliance.

Efficiency data for the initial stock are derived from time-series data on equipment shipments, which are generally available from trade groups.[10] These data are used to develop estimates of retirements and retiring efficiency of appliances over the RDM modeling horizon.

For purchases of new and replacement equipment, a "menu" of technology characterization data provides the RDM with the equipment available for consideration at any point in the forecast horizon. The menu includes a range of current technologies taken from equipment on the market today. The menu changes in response to efficiency standards by dropping equipment that fails to meet the standard from the menu. For new and improved technologies, the menu reflects combinations of greater energy efficiency and/or lower equipment costs. Future technologies are generally based on the evolution of current technologies, not major innovations.[11]

Other RDM inputs include estimated housing stock retirement rates, historical heating and cooling degree-days, calibration information for historical and near-term projection years from EIA's State Energy Data

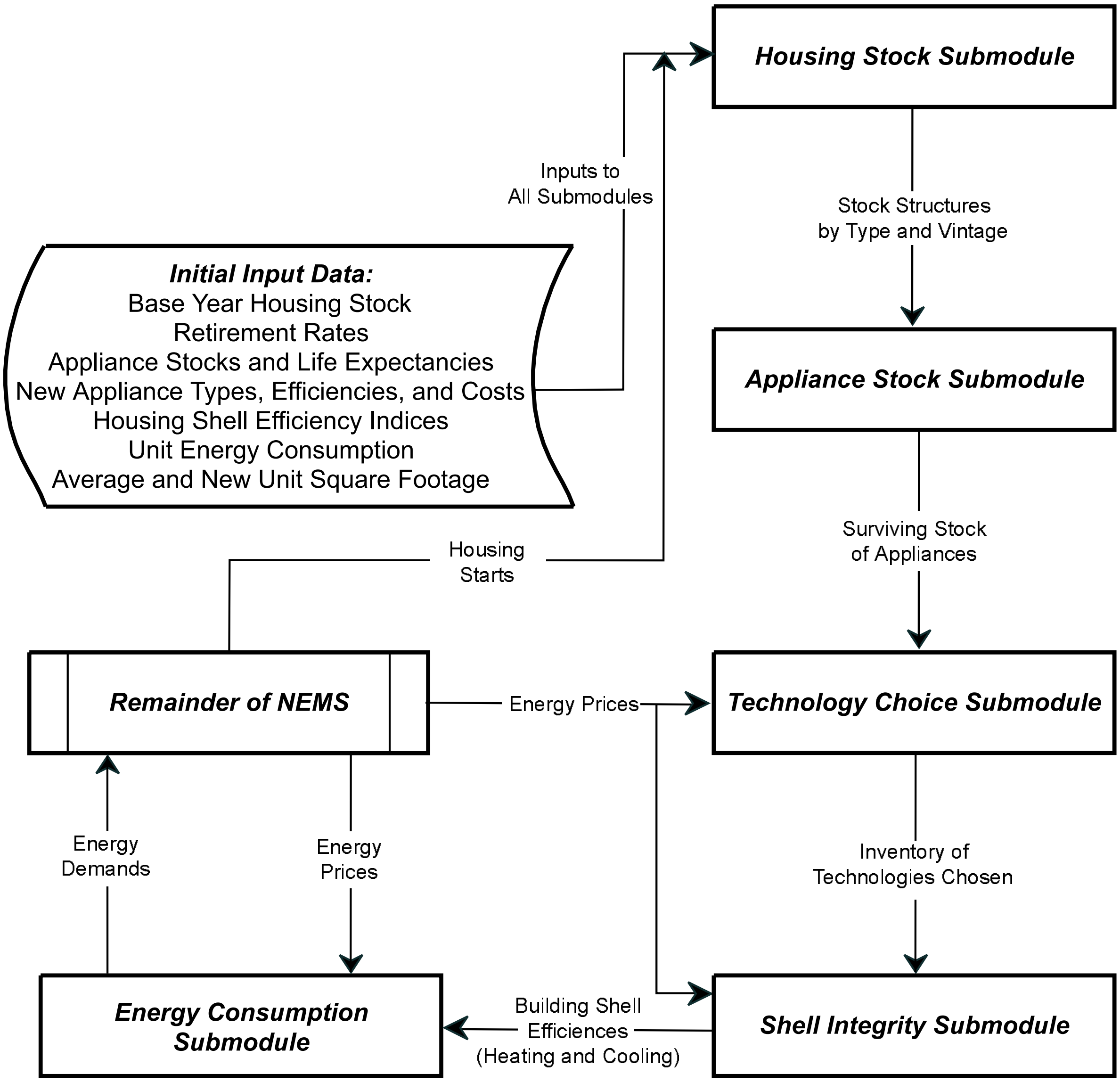
[8]See Energy Information Administration, *Residential Energy Consumption Survey: Housing Characteristics 1993*, DOE/EIA-0314(93) (Washington, DC, June 1995), and *Residential Energy Consumption Survey: Household Energy Consumption and Expenditures 1993*, DOE/EIA-0321(93) (Washington, DC, June 1995).

[9]Information published for the RECS, like the Commercial Buildings Energy Consumption Survey described later, is developed through two sequential surveys over a 2-year period. These surveys are conducted every 3 to 4 years. The 1997 RECS—the next update of the survey—completed the initial buildings characteristics survey for 1997. The data were quality reviewed and updated in the second quarter of 1998. The corresponding energy consumption survey portion of the 1997 RECS will not begin until early 1999. Responses are expected from May through August 1999. Consequently, the final 1997 RECS report will not be available until the beginning of the fourth quarter of 1999. The next edition of RECS is scheduled for 2001 and probably will be published in 2003.

[10]Among the sources of the shipment data are the Association of Home Appliance Manufacturers, *FACT Book*; Air Conditioning and Refrigerator Institute; Gas Supply Manufacturers Association; and Lawrence Berkeley National Laboratory, *Energy Data Sourcebook for the U.S. Residential Sector*, LBL-40297 (Berkeley, CA, May 1997), and *Appliance Data Assumptions and Methodology for Residential End-Use Forecasting with EPRI-REEPS (1993)* (Berkeley, CA, September 1993).

[11]The primary source of data for the technology menu is Arthur D. Little, Inc., *EIA—Technology Forecast Updates*, Reference No. 41615 (June 20, 1995).

Figure 2. NEMS Residential Demand Module



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

System and *Short-Term Energy Outlook*, assumed appliance stock minimum and maximum life expectancies, housing shell integrity for new construction, and fuel choices for single- and multifamily housing types (from the Census Bureau's *Characteristics of New Housing*, 1994).

Module Components and Important Interactions with NEMS

The components of the RDM and its interactions with NEMS are shown in Figure 2. NEMS provides the RDM with forecasts of residential energy prices and housing starts by building type and Census division. These inputs are then used by the RDM to develop forecasts of energy consumption by fuel and Census division, which are passed back to the NEMS integrating module.

Inside the RDM, the Housing Stock Submodule begins the projection cycle for a particular model year by determining the total residential housing stock. The current-year stock is developed by adjusting the previous year's housing stock for new starts and housing retirements for each of the three building types.

The next action is taken by the Appliance Stock Module, which (1) removes appliances for housing units that were retired from the stock, (2) determines appliances required for new construction, and (3) retires appliances in surviving housing that have reached the end of their useful life. For cases (2) and (3), appliances will need to be purchased. Information on these requirements is passed on to the Technology Choice Submodule, which is discussed in detail below. Briefly, the Technology Choice Submodule combines projected energy costs of an appliance (derived from projected energy prices and appliance energy and operating requirements) with equipment cost and performance data to determine new purchases by efficiency level. The submodule is calibrated to recent shipment efficiency data by adjusting parameters that relate to consumer preferences for energy efficiency.

The Shell Integrity Submodule sets shell improvements, which are of two types: (1) autonomous changes to shell efficiency for new and existing construction (improvements that are independent of price), and (2) energy-price-induced changes to shell efficiency for existing construction. The second effect operates as a "ratchet"—there are no reductions in shell efficiency as energy prices decline. Adjustments to heating and cooling requirements are based on the shell improvements set by the Shell Integrity Submodule.

Finally, the Energy Consumption Submodule determines the end-use energy requirements and returns consumption estimates to the NEMS integrating module. The energy requirements include adjustments for changes to the number of appliances in the equipment stock and the energy efficiency of the stock as provided by the Technology Choice Submodule. The Energy Consumption Submodule also makes a variety of other intensity adjustments for effects that include:

- Changes in real energy prices via the short-term price elasticity of demand
- Efficiency rebound effects, which operate similarly to the short-run price elasticity (e.g., increasing thermostat set points for heating when purchases of highly efficient equipment reduce the marginal costs of doing so)
- Short-term weather effects (the model needs to be adjusted for base-year weather versus long-term expectations of climate)
- Changes in consumption for heating and cooling due to increases in shell integrity
- Changes due to demographic effects, such as the effects on heated water consumption of changes in the number of persons per household
- Changes for structural effects, such as increasing average floorspace for single-family housing units.

When all these adjustments have been made, the Energy Consumption Submodule computes energy consumption by fuel and Census division and passes the information back to the rest of NEMS for response.

The Technology Choice Submodule

Figure 3 outlines the general workings of the Technology Choice Submodule. The choice of equipment incorporates important residential market attributes—the tendency not to replace equipment until it fails and the tendency to replace equipment with the same technology when it does fail. Technology choice is modeled in two stages in the RDM. The first stage selects fuel and general equipment type (for example, natural gas furnace for space heating). The second stage selects the efficiency of the equipment type selected in the first stage (the furnace).

For appliance purchases in new construction, both stages of equipment selection are required. For replacement equipment purchases, the market is divided into two groups. One group keeps the same equipment (and fuel) and thus skips the first stage of technology choice. The other group considers technology switching, and after adding any fuel switching costs (e.g., running a gas line to a formerly electric home), proceeds through both stages of equipment selection. In both choice stages, the RDM uses a logistical choice function to project the equipment shares.[12] By design, this functional form results in some purchases being made from each type of available equipment.

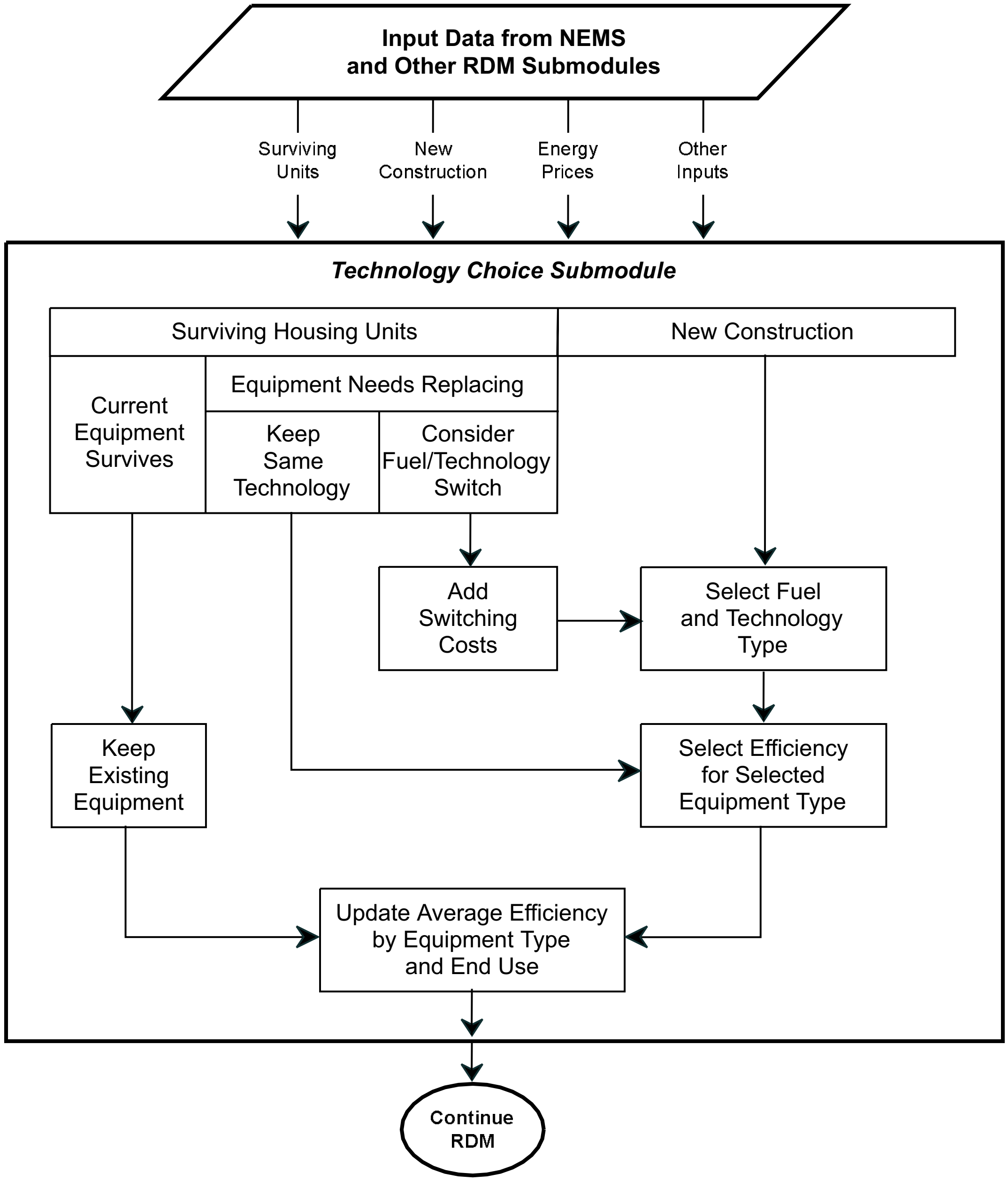
The shares of a specific piece of equipment depend on two factors relative to those of other alternatives: the installed equipment cost and the annual operating costs (fuel plus maintenance). These two cost factors, combined via the logit parameters for installed cost and operating cost, determine the share of a particular equipment type relative to others. The parameters are chosen to calibrate the average efficiency choices to those observed for recent shipment data, when available. Approximate discount rates can also be derived from the logit parameters. The discounts rates are referred to as "implicit" discount rates, because they represent the discount rate implicitly used in evaluating purchase decisions based on observed market behavior. The implicit discount rates in the RDM are generally higher than purely financial discount rates and include effects of other factors (uncertainty, institutional barriers, and

[12]For example, the logit function for the efficiency choice for each combination of fuel and technology (electric heat pumps, gas furnaces, etc.) is based on a function of the form:

$$S = exp\,(\alpha FC_i + \beta OM_i \;/\; \sum_{j=1,n}\left[exp\,(\alpha FC_j + \beta OM_j)\right] \quad ,$$

where FC_i is the installed cost, OM_i is the operation and maintenance cost of efficiency choice *i*, and *n* is the number of efficiency choices available for selection. The parameters α and β are specific to the combination being considered. Their values are set so that modeled choices closely track actual purchased efficiencies. The approximate implicit discount rate for the efficiency decision is the ratio of α to β. For a further description of the choice methodology and equations, see Energy Information Administration, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M067(98) (Washington, DC, January 1998).

Figure 3. NEMS Residential Demand Module, with Emphasis on Technology Choice



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

perceived risks) that influence residential energy-efficiency choices.[13] The implicit discount rates are specific to general types of equipment (electric heat pumps, gas furnaces, etc.). For *AEO98*, the implicit discount rates range from 15 to 50 percent for efficiency choices of space heating and central air conditioning equipment. For heat pumps, which are highlighted in the discussion below, the approximate implicit discount rate used in the RDM is 20 percent.

Because the intensity of a particular end use varies considerably across the nine Census divisions while the installed costs do not, the tradeoff between installed cost and maintenance and energy costs varies by Census division. Thus, in divisions with high usage intensity, the RDM selects, on average, somewhat more efficient (and more costly) equipment. Similar differences in choice of efficiency due to usage intensity occur across building types.

[13]Among the reasons often cited for relatively high apparent discount rates for energy efficiency choices are uncertainty about future energy prices and thus about the returns from an energy-efficiency investment; lack, or high cost, of good information on efficiency and savings; short tenure, causing some of the gains for energy efficiency investments to be lost to the purchaser; renter/owner incentive differences, such as master metering of apartments, so that energy savings do not accrue to the tenant; and builder incentives to minimize construction costs of speculative housing. For a discussion of potential market failures and the economics of energy efficiency decisions, see A. Jaffe and R. Stavins, "Energy Efficiency Investments and Public Policy," *The Energy Journal*, Vol. 15, No. 2 (1994), pp. 43-65.

Equipment choices are made from a menu of the technologies available to serve a given end use in a particular year. Each end use is potentially served by several technologies, each with multiple efficiency levels available. Generally, two to four different efficiencies are available for a given technology.

The technology menu includes a variety of characteristics for residential appliances:

- The retail cost of equipment plus installation costs (tracked separately)
- The energy efficiency of the equipment
- The dates available for purchase (for example, efficiency standards may limit availability for future years, or technological innovations may cause new equipment to become available in future years)
- Equipment minimum and maximum lifetimes
- Choice function parameters, which vary by appliance type and generally are calibrated to recent shipments.

Table 1 provides data from the *AEO98* menu of technologies for several types of equipment.[14]

Technology Choice Comparison Cases

A comparison of choices of heat pumps for three electricity price cases illustrates some of the features of the residential technology choice methodology. By incorporating only price changes, it is easier to isolate and explain model responses. The prices in these cases are arbitrarily increased, with no cause attributed for the increases. No attempt is made to construct integrated scenarios.

The baseline is the *AEO98* reference case. The Doubling Case assumes that electricity prices in each year are twice those in the reference case, beginning in 2000 and continuing to 2020, the last year of the projection period. This assumption results in declining prices after 2000, as also seen in the reference case. In the Doubling with Increasing Prices Case, electricity prices are again doubled in 2000 (over the reference case) but increase, rather than decrease, for the remainder of the projection horizon. This increase is symmetrical to the decrease over

Table 1. Selected Residential-Sector Technology Cost and Performance Characteristics

Equipment Type	Relative Performance[a]	1995 Installed Cost (1996 Dollars)[b]	1995 Efficiency[c]	2005 Installed Cost (1996 Dollars)[b]	2005 Efficiency[c]	Approximate Discount Rate (Percent)[d]
Electric Heat Pump	Minimum	3,295	10.0	3,295	10.0	20
	Best	5,648	14.5	5,648	16.9	
Natural Gas Furnace . . .	Minimum	1,530	0.78	1,530	0.78	15
	Best	3,530	0.95	2,941	0.96	
Room Air Conditioner . . .	Minimum	706	8.7	706	9.7	100
	Best	1,000	12.0	1,000	12.5	
Central Air Conditioner . .	Minimum	2,471	10.0	2,471	10.0	50
	Best	3,530	14.5	3,588	16.9	
Refrigerator (18 cubic ft) .	Minimum	588	690	588	483	19
	Best	765	550	823	400	
Electric Water Heater . . .	Minimum	412	0.88	412	0.88	111
	Best	1,765	2.60	1,246	2.80	

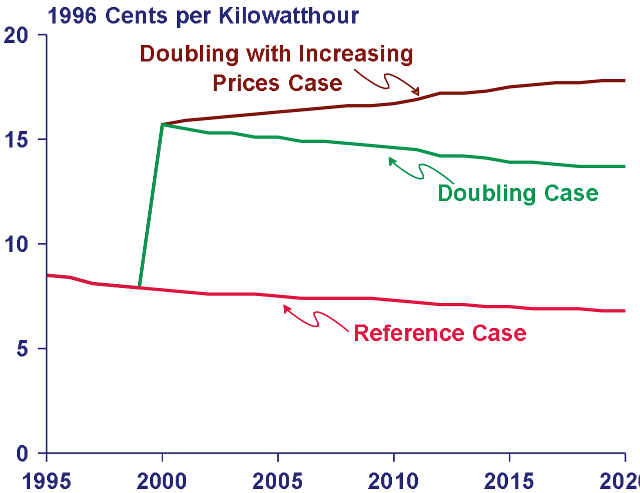
[a]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.
[b]Installed costs, shown in 1996 dollars, include retail equipment costs plus installation costs for average unit sizes. Actual sizes and equipment costs can vary.
[c]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated above for cooling performance using the Seasonal Energy Efficiency Ratio (SEER). Heating performance of heat pumps is measured by the Heating Season Performance Factor (HSPF). For the heat pumps shown, the HSPF ratings are 6.8 and 10.2 for 1995 and 6.8 and 11.0 for 2005. Natural gas furnace efficiency ratings are based on annual fuel utilization efficiency. Room air conditioner ratings are based on seasonal energy efficiency ratio (SEER). Refrigerators ratings are based on kilowatthours per year. Water heater ratings are based on energy factor (delivered Btu divided by input Btu).
[d]Although the RDM does not use discount rates directly in evaluating efficiency purchase decisions, approximate discount rates can be derived from the parameters of the equipment choice model.
Source: Arthur D. Little, EIA Technology Forecast Updates, Reference Number 41615 (June 1995).

[14]The cost and performance characteristics of residential (and other end-use) appliances reflected our best estimates of the equipment and installation costs of complete new systems when the *AEO98* projection was developed. Replacement units will often cost less than complete systems when only a portion of the system fails and is being replaced. Equipment costs are being reviewed and updated for *AEO99*.

the same period in the reference case and Doubling Case (Figure 4).

An important feature of the *AEO98* projections is that average real residential electricity prices are projected to decline during the projection period, largely as a result of increasing competition in electricity generation markets, declining coal prices, and relatively stable gas prices. For the reference case, residential electricity prices decline from about 8.5 cents per kilowatthour in 1995 to 7.8 cents in 2000 to 6.8 cents per kilowatthour by 2020. The Doubling Case was constructed with a jump in electricity prices in the year 2000 to just over 15.7 cents per kilowatthour. From 2000 on, prices decline to 13.7 cents per kilowatthour in 2020. This decline is proportional to the decline for the same period in the reference case. For the Doubling with Increasing Prices Case, electricity prices increase from 15.7 cents per kilowatthour in the year 2000 to 17.8 cents per kilowatthour in 2020.

Figure 4. Residential Electricity Prices, 1995-2020

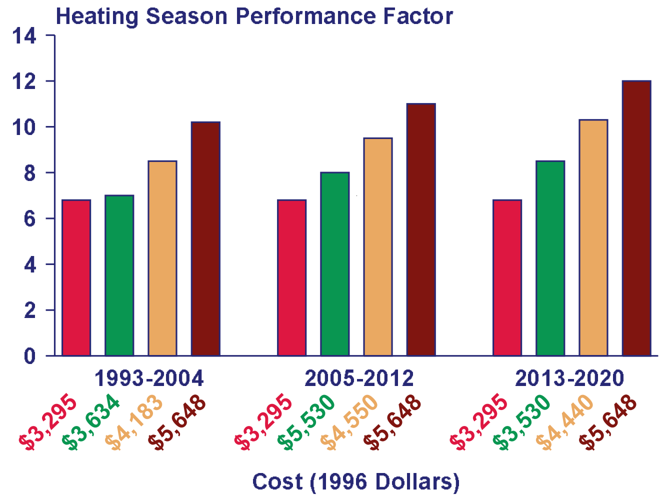


Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A (reference case), ELAST98.D042098A (Doubling Case), and ELAST98.D042098B (Doubling with Increasing Prices Case).

Figure 5 illustrates the prices for heat pump equipment of different efficiencies over the projection horizon. The efficiency ratings in Figure 5 refer solely to the space heating component of performance, represented by the heating season performance factor (HSPF) of the heat pump. The HSPF is typically only about two-thirds that of the air conditioning efficiency rating for a heat pump measured as the seasonal energy efficiency ratio (SEER). Hence, in 2020, while the most efficient unit has an HSPF of 12, the average SEER for the same unit is 18.

The data are divided into three intervals of availability (Figure 5). Each bar represents the efficiency of an available heat pump, and for each of the three intervals, four levels of efficiency are assumed to be available. The installed costs are shown in constant 1996 dollars. During the first interval, which extends through 2004,

Figure 5. Installed Costs and Efficiencies of Heat Pumps, 1993-2020



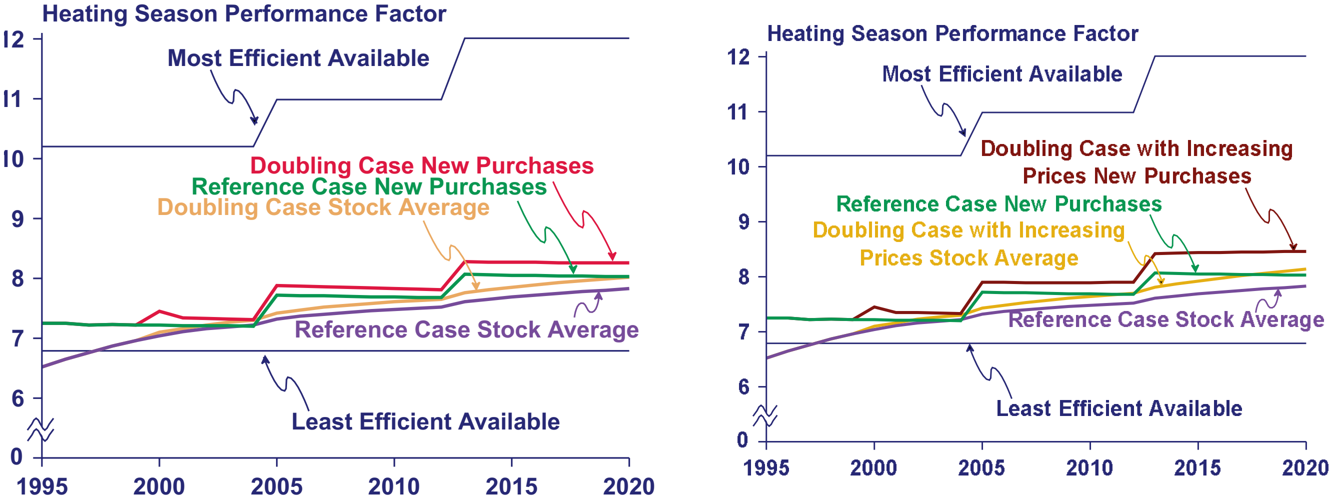
Source: AEO98 National Energy Modeling System, technology data.

the minimum efficiency heat pump (HSPF 6.8) costs $3,295 installed. This unit is available, unchanged, in the other two intervals, since no future efficiency standards currently apply. The highest efficiency unit in the first interval is roughly 50 percent more efficient than the minimum efficiency unit, with an installed cost of $5,648, or about 70 percent higher than the cost of the minimum efficiency unit. For the reference case, technological progress for residential heat pumps generally makes higher efficiency units available at either the same cost as in previous intervals or at only a slightly higher cost (depending on the two intervals being compared). In the third interval, the most efficient heat pump is roughly 75 percent more efficient than the minimum efficiency model, although its costs are still only about 70 percent greater.

Figure 6 compares stock and purchased efficiency for the two high price cases relative to the reference case. Stock efficiency merely represents the average efficiency of all heat pump equipment, much of it purchased before standards were adopted in 1992. The stock efficiency changes as new equipment is added for newly constructed housing units, as housing units and any associated equipment decay from the housing stock, and as equipment wears out and is replaced in surviving housing units. Stock efficiency starts out below the current standard (due to the “inertia” of purchases made before the standard was adopted), but by 1998 climbs to a level above the minimum efficiency requirement for new purchases.

In 2000, purchased efficiency in the Doubling Case increases, driven by the increase in operating costs due to higher electricity prices. In 2001, efficiency moves back toward the reference case levels. The reduction in purchased efficiency from 2000 to 2001 has three causes, all of which relate to decreases in operating costs for heat pumps in the year 2001 relative to the year 2000. First,

Figure 6. New Purchase and Stock Average Efficiencies of Heat Pumps, 1995-2020



Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A, ELAST98.D042098A, and ELAST98.D042098B.

the price doubling causes an approximate reduction of 15 percent in electric space heating energy demand due to the short-run price elasticity effect; the reduced energy demand also reduces operating costs by the same 15 percent over what they would have been based on the previous year's demand. Second, in 2001, space heating energy demand further declines because of the fuel-price-induced increases in shell efficiency, which also reduce operating costs for space heating equipment. Third, from 2000 to 2001, real energy prices decline in this case (Figure 4), directly lowering space heating operating costs in 2001 relative to 2000. The first and second effects are largely responsible for the drop from 2000 to 2001—their effects are fully reflected by 2001. The third effect continues as long as real energy prices continue to decline (which they do for all years after the initial doubling).

In the Doubling Case, purchased efficiency declines between the first and second years of the price shock. For subsequent years, the relative influence of the three effects changes. The first effect cited above, short-run price elasticity of demand, weakens slightly as real energy prices decline from their high point in 2000. The second effect, related to increased shell efficiency, stays at the same level as in 2001, since real energy prices do not increase further over the projection period. The third effect, the direct effect of prices on operating costs, also weakens slightly as real energy prices fall.

Continuing with the Doubling Case, the primary feature of the interval from 2001 through 2004 is a very slight, but visually noticeable decline in purchased efficiency, due mainly to the long-term price decline after the initial price shock. In 2005, the effects of changes to the technology menu for heat pumps is evident from the increase in purchase efficiency that occurs when more efficient heat pumps are projected to become available at installed costs comparable to those of less efficient pre-2005 units. A similar "menu effect" occurs in 2013. During the intervening periods, the intervals can be characterized as exhibiting slightly lower efficiency choices at the end than at the beginning of the intervals in response to the declining real energy prices.

The Doubling with Increasing Prices Case examines residential heat pump market behavior when electricity prices double over the reference case in 2000 to 15.7 cents per kilowatthour and then increase further to 17.8 cents per kilowatthour by 2020. In this case, the adoption of new technology in more efficient categories is more pronounced, because continuously rising electricity prices make the more efficient equipment more economical than it would be if electricity prices were flat. Consequently, new appliance efficiencies increase progressively through time. However, the electricity price is still not high enough, nor the capital cost differences small enough, to allow the more advanced heat pumps to capture even 50 percent of the market for new purchases.

As illustrated in Figure 6, average stock efficiency is relatively slow to change because of the inertia created by the 12-year average equipment life for heat pumps. New purchases of equipment are, on average, only about 20 to 25 percent more efficient than the projected average efficiencies. Under the RDM assumptions, a doubling in electricity prices is insufficient to cause consumers to purchase the most efficient heat pump equipment available. In fact, only a small portion of the new market purchases are for the third most efficient heat pump, which costs $4,550 and has an HSPF efficiency rating of 9.5.

To understand why greater adoption of the more efficient versions is not projected, compare the costs and efficiencies from the middle period (2005-2012). The difference in installed costs for a heat pump with an HSPF of 8 (unit cost $3,530) and one with an HSPF of 9.5 (unit cost $4,550) is $1,020. The latter unit will consume about 16 percent less electricity for both heating and cooling. An average home using a heat pump with an HSPF of 8 would require about 5,500 kilowatthours per year for heating and cooling. If the unit with a 9.5 HSPF were purchased instead, the reduction in electricity consumption would be 880 kilowatthours per year. At an average electricity price of $0.146 per kilowatthour (from the Doubling Case in 2010), the average annual cost savings would be about $128. The undiscounted or simple payback period for this example is 8 years.[15] For the evaluation of heat pump purchases, the RDM uses an implicit discount rate of approximately 20 percent, which is consistent with a simple payback period of just under 4.5 years.

The Commercial Demand Module

As a component of NEMS, the Commercial Demand Module (CDM) has many of the same structural requirements and features as the Residential Demand Module. The CDM forecasts energy consumption by Census division for eight marketed energy sources plus solar thermal. For the three major commercial-sector fuels—electricity, natural gas, and distillate—the model is structural, and its forecasts are derived from projections of commercial floorspace stock and end-use energy-consuming equipment. For the remaining minor fuels, the forecasts are simple projections based on past trends and energy prices.

Demand for each of the major fuels, 11 building types and 10 end uses are modeled for each of the nine Census divisions. The commercial end uses are heating, cooling, ventilation, water heating, lighting, cooking, personal computers, non-PC office equipment, refrigeration, and other miscellaneous. The CDM building types are assembly, education, food sales, food service, health care services, lodging, office-large, office-small, mercantile and service, warehouse, and other. The technology characterizations and equipment choices apply to what are considered to be "major end uses." For *AEO98*, the services, personal computer office equipment, other office equipment, and other miscellaneous end uses are considered "minor services," modeled using exogenous equipment efficiency and market penetration trends.

Commercial sector energy is consumed mainly in buildings, except for a relatively small amount for services such as street lights, water supply, and waste treatment. The CDM incorporates the effects of four broadly defined determinants of energy consumption: economic and demographic effects, structural effects, technology change and equipment turnover, and energy market effects. Demographic effects include total floorspace, building type, and location. Structural effects include changes in the mix of desired end-use services provided by energy (such as the penetration of telecommunications equipment, personal computers, and other office equipment). Technology effects include changes in the stock of installed equipment caused by normal turnover of old, worn-out equipment and replacement by newer versions that tend to be more energy efficient; the integrated effects of equipment and building shell (insulation level) in new construction; and the projected availability of equipment with even greater energy efficiency. Energy-market effects include the short-run effects of energy prices on energy demands, the longer run effects of energy prices on the efficiency of purchased equipment, and limitations on minimum levels of efficiency imposed by legislated efficiency standards.

Data Sources

The CDM is initialized with data characterizing building and appliance stocks for its base year, currently 1992. The CDM relies on EIA's Commercial Buildings Energy Consumption Survey (CBECS) for a large part of this initial information. CBECS is a nationally representative, stratified sample based on a detailed survey of more than 6,000 commercial buildings. CBECS building and equipment characteristics are derived directly from the survey data. Since no appliance-level metering of energy is performed for the CBECS, its end-use consumption data are derived from an engineering and statistical analysis of monthly energy bills for the surveyed buildings. The 1992 edition of CBECS[16] was used as the basis for *AEO98*. The key data obtained from CBECS are estimates by Census division for the following:

- Base commercial floorstock—floorspace area by building type and age
- General characterizations of initial equipment stocks (i.e., percentage of floorspace served and type of energy-consuming equipment, but not efficiency)
- Estimated energy consumption by end use.

Equipment characterizations and base-year efficiency estimates are derived from a series of studies supporting

[15]Using appropriate discounting would lengthen the payback period in each case, and for economic reasons the efficiency upgrade would not be made. The internal rate of return over 12 years is under 7 percent. At a price of 16 cents per kilowatthour, the payback period for the 9.5 HSPF technology relative to the 8 HSPF decreases from 8 years to just over 7 years—still not sufficient to trigger wide market preference. Based on the implicit discount rate of 20 percent in the RDM, the installed cost difference between the 8 HSPF and 9.5 HSPF heat pumps would have to be just under $600 before a 4.5-year payback would be achieved and significant market share for the higher efficiency unit would be projected in the Doubling Case.

[16]The CDM is currently being updated to the 1995 CBECS; the energy consumption data became available in January 1998 due to the lengthy time required to survey and process the data. Like RECS, CBECS is updated once every 3 to 4 years. For the *AEO98* sources, refer to Energy Information Administration, *Commercial Buildings Energy Consumption Survey: Commercial Buildings Characteristics 1992*, DOE/EIA-0246(92) (Washington, DC, April 1994) and *Commercial Buildings Energy Consumption Survey: Commercial Buildings Energy Consumption and Expenditures 1992*, DOE/EIA-0318(92) (Washington, DC, April 1995). The next edition of CBECS will be for 1999, and the data probably will be published in 2001.

the CDM.[17] For equipment purchases, a menu of technology characterization data provides the CDM with the equipment available for consideration at any point in the forecast horizon. The equipment menu includes only technologies that satisfy Federal efficiency standards, by discontinuing equipment that fails to meet the standard, and includes the range of equipment available in the market today. The menu changes in response to changes in efficiency standards. New and improved technologies are reflected in the menu by combinations of greater energy efficiency and / or lower equipment costs. Future technologies are generally based on improvements of current technologies, not technological breakthroughs.

Other CDM inputs include estimated floorspace retirement rates, historical heating and cooling degree-days, calibration information for historical and near-term projection years from EIA's State Energy Data System and *Short-Term Energy Outlook*, assumed appliance life expectancies, and projections of building shell efficiency levels for existing and new construction.

The CDM is initialized, partially from CBECS data, with a regional, vintaged accounting of existing commercial floorspace by building type, floorspace survival rates, appliance stocks and survival rates, the menu of new appliances to be available with their survival rates, dates of initial availability, costs, efficiencies, appliance or building standards required by law, and energy-use intensities (energy use per square foot).

Module Components and Important Interactions with NEMS

The CDM and its interactions with NEMS are shown in Figure 7. As illustrated, the CDM carries out a sequence of four basic steps. The first step is to forecast commercial sector floorspace. The second step is to forecast the energy services (space heating, lighting, etc.) required by the projected floorspace. The third step is to select specific technologies to meet the demand for energy services. The last step is to determine how much energy will be consumed by the equipment chosen to meet the demand for energy services.

NEMS provides the CDM with projections of energy prices, interest rates, and floorspace growth rate by building type. These projections are combined with the initial information and the inventory of decisions made in previous years to determine equipment stocks and fuel consumption for the current year.

The Floorspace Submodule begins with a base stock of commercial floorspace by Census division and building type derived from the 1992 CBECS. The CDM receives forecasts of total floorspace by building type and Census division from the NEMS interface based on Data Resources, Inc. (DRI-Dodge) projections. Because the definition of commercial floorspace used by DRI-Dodge is not the same as that used for CBECS, the CDM estimates the surviving floorspace from the previous year and then estimates new construction by calibrating CBECS-based floorspace growth to the growth from the DRI-Dodge projections by building type and Census division.[18]

In the next major step, the Energy Service Demand Submodule forecasts energy service demands for the projected floorspace. Energy service demands are given in terms of units of energy services required (output after the "burner tip")—for example, annual million Btu of space heating output per square foot.[19] Different building types require unique combinations of energy services. A hospital requires more lighting output per square foot than a warehouse. An office building in the Northeast requires more heating output per square foot than a similar building in the South. Thus, total service demand depends on the floorspace, type, and location of buildings. Base service demand by end use, building type, and Census division is derived from estimates developed from CBECS energy consumption and base-year equipment efficiencies. Projected service demands are adjusted for trends in new construction based on CBECS data for recently constructed buildings (i.e., the percentages of new construction heated, cooled or lighted).

Equipment Characterizations and Choice Methodology

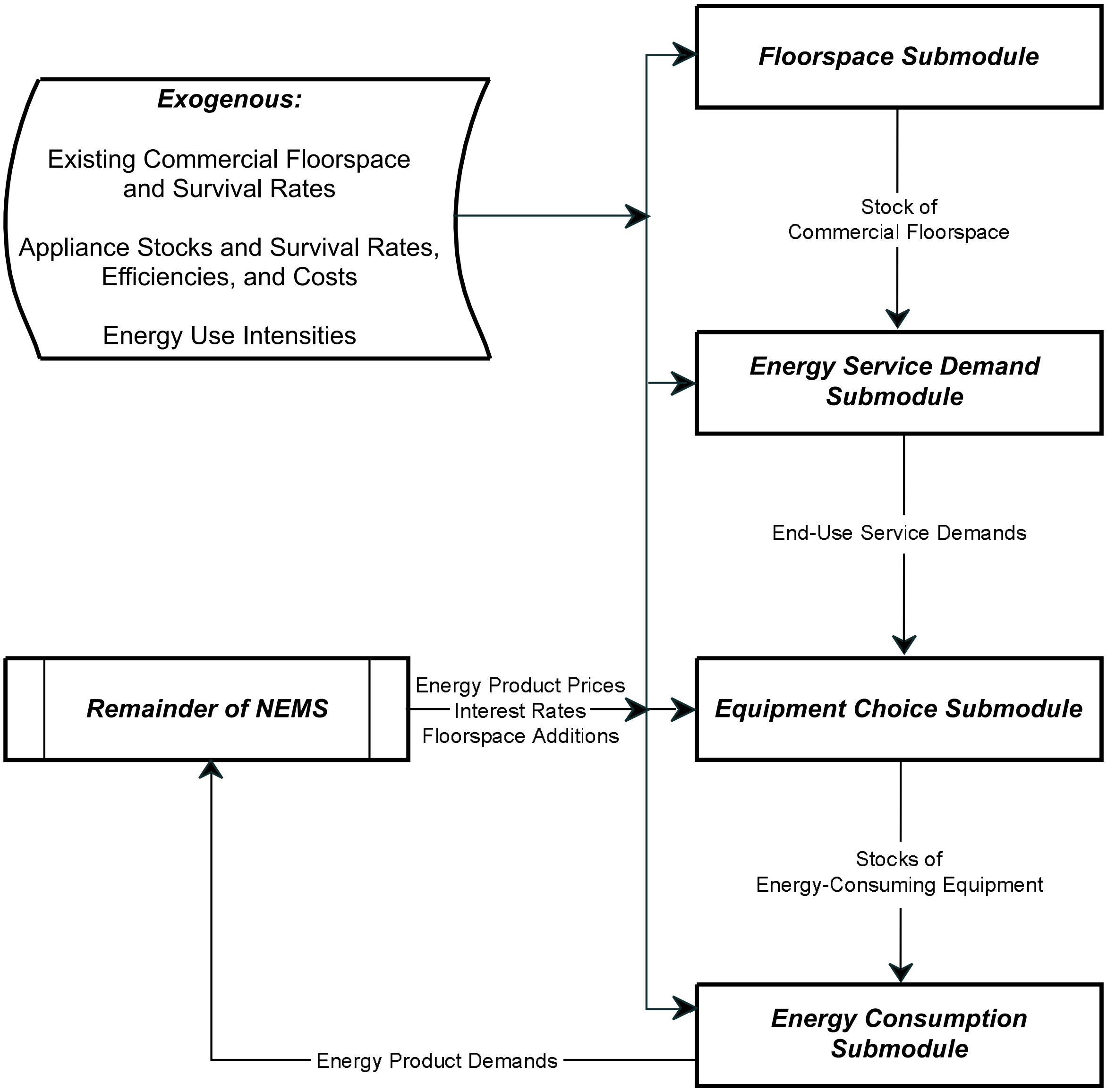
Once service demands are projected, the next step is to determine what equipment will be used to meet the service demand. The CDM bases equipment choices on minimizing life-cycle costs. To ensure that no single technology becomes dominant, "market segmentation" is employed to reflect the diversity of observed market behavior.

[17]The three primary sources of data for the technology menu are Arthur D. Little, Inc., *EIA—Technology Forecast Updates*, Reference No. 41615, prepared for the U.S. Department of Energy under Contract DE-AC01-92EI21946 (Washington, DC, June 1995); Decision Analysis Corporation of Virginia, *Lighting Systems Technology Characterizations for the NEMS Commercial Sector Demand Module*, prepared for the Energy Information Administration under Contract DE-AC01-92EI21946 (Washington, DC, August 1996); and Decision Analysis Corporation of Virginia, *Ventilation Systems Technology Characterizations for the NEMS Commercial Sector Demand Module*, prepared for the Energy Information Administration, Contract DE-AC01-92EI21946 (Washington, DC, August 1996).

[18]The coverage of commercial floorspace in the two sources is different, with CBECS probably covering smaller buildings more completely. For example, the DRI-Dodge estimates for the commercial sector were developed from construction costing $50,000 or more, whereas CBECS includes all buildings larger than 1,000 square feet.

[19]Ignoring adjustments for building shell efficiency, price elasticity of demand, historical weather, and other effects, energy consumption (energy input) is derived after dividing service demand for output by the equipment efficiency (energy output divided by energy input).

Figure 7. NEMS Commercial Energy Demand Module



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

After surviving equipment has been determined, new equipment purchases are calculated to meet the projected service demand. The Equipment Choice Submodule compares the cost and performance across all available equipment to project the type and efficiency that will be used to satisfy the service demands. Due to long-lived building capital stocks, the bulk of equipment required to meet service demand will carry over from the equipment stock of the previous model year. However, equipment must always be purchased to satisfy service demand for new construction and for equipment that has either worn out (replacement equipment) or reached the end of its economically useful life (retrofit equipment). For required equipment replacements, the CDM uses a constant decay rate based on equipment life. A technology will be “retrofitted” only if the combined annual operating and maintenance costs plus annualized capital costs of a potential technology are lower than the annual operating and maintenance costs of an existing technology.

Technology Characterization Data

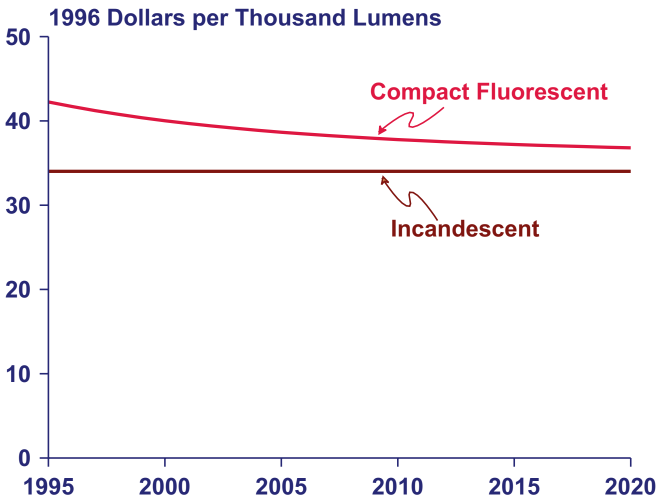
The CDM obtains its technology data from a menu database similar to the one described for the RDM. The primary data characterizing commercial energy technologies are:

- Cost of equipment plus installation and estimated annual maintenance costs
- Equipment efficiency rating
- Equipment life (used for both equipment retirements and annualized cost calculations)
- Fuel type and technology type (used to define technologies that can compete)

- Dates available for selection—"windows of availability" (standards limit how long a technology can be purchased, and new technologies may become available later in the forecast)
- Permitted building types for equipment (some types of equipment are not appropriate for all building types—centrifugal chillers are restricted to use for education, health care, large office, and mercantile / service building types).

The technology menu can embody technological change by allowing more efficient or lower cost versions to become available later in the projection horizon. Changes in technology cost can either be discrete, with a new lower cost version of a technology becoming available in a given year, or they can be "continuous," with a particular technology exhibiting annually declining costs. For the *AEO98*, newer lighting technologies have continuous annual cost declines. Figure 8 compares the annual declines in installed costs projected for compact fluorescent lighting with the constant installed costs of the "mature" incandescent lighting technology.

Figure 8. Installed Capital Costs for Lighting Technologies, 1995-2020



Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A, ELAST98.D042098A, and ELAST98.D042098B.

Behavior-Rule Restrictions

Equipment choices are made to minimize annualized capital, fuel, and maintenance costs across all allowable equipment for a particular end-use service. Further segmentation of the market is required to reflect competition more accurately, and to avoid the possibility that all new purchases in the projections for a given combination of building type and Census division will instantly switch to the minimum-cost technology—an unrealistic outcome. Restrictions in terms of how widely technologies can compete are therefore used to add "inertia" to the equipment choices. The restrictions apply to segments of floorspace for which only subsets of the total menu of potentially available equipment are allowed. For example, for replacement space heating equipment in large office buildings, 8 percent of floorspace is free to consider all available equipment using any fuel or technology. A second segment, 33 percent of floorspace, must select from technologies using the same fuel as already installed. A third segment, the remaining 59 percent of floorspace, is constrained to consider only different efficiency levels of the same fuel and technology already installed.[20]

For major end-use categories (e.g., lighting) that include diverse subsets of end uses served by potentially different technologies (e.g., exterior versus interior lighting), special restrictions are required to prevent inappropriately rapid departures from historical equipment shares. Continuing with the lighting example, exterior lighting has cost and performance characteristics much different from those of interior lighting. Exterior lighting equipment, which does not require the same level of color-rendering capabilities as interior lighting, is the most efficient equipment available (i.e., it has the highest efficacy in terms lumens of output per watt). For example, exterior parking lights do not emit the full spectrum of light; consequently, color photos may appear grey or subdued when viewed with that type of lighting. Left to compete with interior lighting equipment, exterior types would penetrate significantly and inappropriately. Thus, lighting as an end use is restricted to same technology decisions. Same technology allows minimizations of life-cycle costs only for the subset of technologies in the same class as the technology being replaced. In *AEO98*, refrigeration was also restricted in the same manner.[21]

Limiting equipment choices to the same technology is not as restrictive as it sounds. The definition of a technology is controlled by the technology menu system, and technologies can be defined to satisfy as many subcategories of end uses as appropriate. The intent is to encompass principal competing technologies within a technology definition, but to exclude technology types that would not normally compete for a type of service demand. If necessary, technologies can be repeated with different technology types, so that they can compete in two or more technology classes.

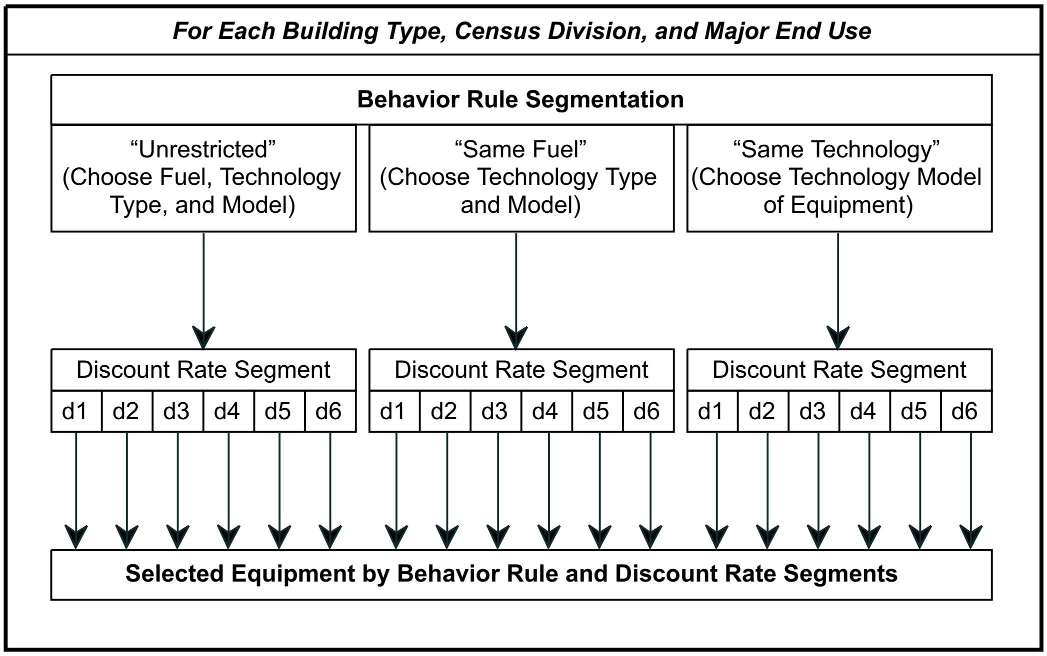
Discount Rate Segmentation

Since equipment choices are made on the basis of minimum life-cycle costs, market segmentation of discount rates can help to ensure that a single technology does not inappropriately "take over" an end use. Six market

[20] New construction also has limitations on choices. As an example, a "same fuel" restriction would allocate new floorspace on the basis of existing shares by fuel type.

[21] Refrigeration includes lower, medium, and higher temperature applications, the shares of which would change inappropriately if full competition across temperature ranges were permitted.

Figure 9. NEMS Commercial Energy Demand Module: Overview of Equipment Purchase Market Segmentation



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

segments (customer groupings) are currently used in the CDM, with rates varying from as low as approximately 20 percent to as high as 150 percent and above to guarantee that only equipment with the lowest capital cost (and usually the lowest efficiency) is chosen. The discount rate segmentation can be viewed as reflecting the spectrum of individual and institutional considerations, preferences, and attitudes toward equipment purchases. As real energy prices increase (or decrease) there will be altered incentives for all but the highest implicit discount rate segments to purchase higher (or lower) levels of efficiency.

Equipment Choice Summary

The segmentation of the equipment choices in the CDM is summarized in Figure 9. Like the RDM, the CDM includes a natural segmentation by Census division and building type, across which both energy prices and service demand intensities can vary. In the CDM, there are two additional levels of segmentation: the competition limitations of the fuel-choice behavior rules and the segmentation of the implicit discount rates. For each end use (within the Census division and building type) and for each behavior rule and discount rate segment, the CDM first computes the annualized capital costs based on the equipment life given in the technology menu. To this, the CDM adds current-year operating and fuel costs for each fuel-technology combination.[22] Finally, the technology with the lowest combined annualized capital and operating and maintenance cost is selected for this decision. The process is then repeated across all the behavior rule and discount rate combinations.

Energy Consumption Submodule

Once the required equipment choices have been made, the total stock and efficiency of equipment for a particular end use are determined. Energy consumption by fuel is calculated in the Energy Consumption Submodule (Figure 7), based on the amount of service demand satisfied by each technology and its corresponding efficiency. In this submodule, other adjustments to energy consumption are also made, including adjustments for changes in real energy prices (short-run price elasticity effects), adjustments in utilization rates caused by efficiency increases (efficiency "rebound" effects), and changes for weather relative to the CBECS survey year. After these modifications are made, total energy use is computed across end uses and building types for the three major fuels for each Census division. Combining these projections with the econometric and trend projections for the five minor fuels yields total projected commercial energy consumption.

Equipment Choice Comparisons for Alternate Electricity Price Cases

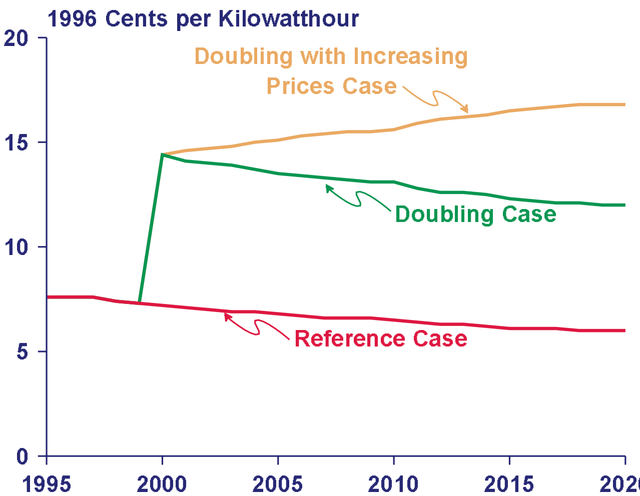
To examine the workings of the commercial technology choice methodology in some detail, a comparison of choices for three price cases follows. Again, the *AEO98* reference case is the baseline for comparisons. The Doubling Case features a doubling of reference case electricity prices beginning in the year 2000 and continuing through 2020. The Doubling with Increasing Prices Case doubles the reference case prices in 2000 and then increases them through 2020. As for the residential

[22]The use of current-year energy prices is referred to as "myopic" cost-minimizing behavior. That is, it is assumed that commercial-sector decisionmakers are not incorporating energy price projections that differ from present prices in their equipment choice decisions.

cases, the increase in the Doubling with Increasing Prices Case from 2000 through 2020 mirrors the declines shown in the reference case and the Doubling Case.

The national average electricity prices for the commercial sector are shown in Figure 10. For the reference case, electricity prices (in constant 1996 dollars) decline from about 7.6 cents per kilowatthour in 1995 to 6.0 cents per kilowatthour by 2020. For the Doubling Case, there is a jump from 7.2 cents per kilowatthour in 1995 to 14.4 cents per kilowatthour in 2000, followed by a decline to 12.0 cents per kilowatthour by 2020. This decline is proportional to the decline for the same period in the reference case. In the Doubling with Increasing Prices Case, prices increase from 14.4 cents per kilowatthour in 2000 to 16.8 cents by 2020.

Figure 10. Commercial Sector Electricity Prices, 1995-2020

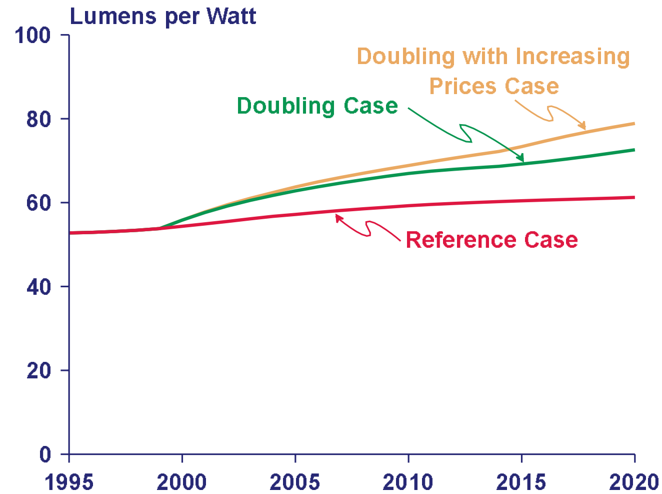


Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A, ELAST98.D042098A, and ELAST98. D042098B.

The end-use service selected for detailed comparisons is lighting. Figure 11 shows the average efficiency of the lighting stock for the three cases. In the reference case, overall efficiency grows from 52.8 to 61.3 lumens per watt, an average annual increase of 0.6 percent. In the Doubling Case, efficiency grows to 72.6 lumens per watt, averaging 1.3 percent per year. In the Doubling with Increasing Prices Case, efficiency grows to 78.9 lumens per watt, averaging 1.7 percent per year.

To illustrate the choices that drive the efficiency gains, the service demands met by the various technologies of lighting stock are examined.[23] The 33 technology subtypes from the *AEO98* (see Appendix A for the key menu elements for *AEO98* lighting technologies) have been aggregated to eight categories: incandescent, compact

Figure 11. Commercial Sector Lighting Efficiencies, 1995-2020



Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A, ELAST98.D042098A, and ELAST98. D042098B.

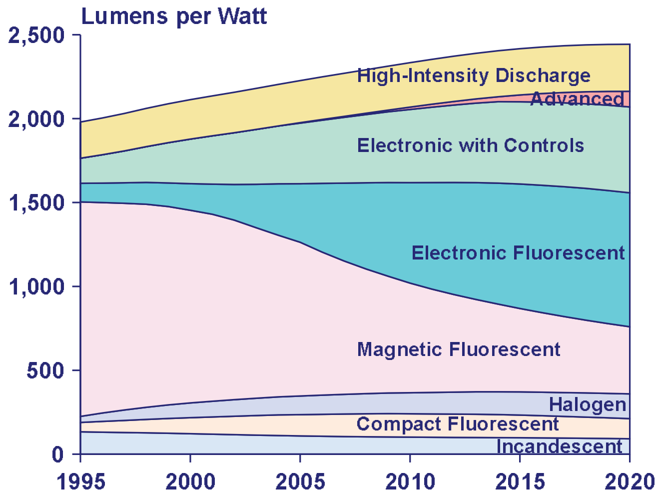
fluorescent (CFL), halogen, fluorescent (magnetic, electronic, and electronic with controls), advanced lighting technologies, and high-intensity discharge (HID) lighting (used primarily for exterior and warehouse lighting).

Figure 12 shows the evolution of technologies in the reference case. The notable feature of the reference case is that even with declining electricity prices, the lighting market evolves in a number of areas. Technologies gaining market share are CFL, halogen, electronic ballast fluorescent, and advanced lighting. Incandescent and magnetic ballast fluorescent shares decline, while HID lighting is relatively stable. These changes are generally the result of declining costs for newer electronic technologies (especially CFL and electronic ballast fluorescent) and the introduction into the menu of equipment in the advanced lighting category beginning in 2000, with additional introductions in 2005, 2010, and 2015 (see Appendix A for further detail regarding the introduction of specific technologies in the advanced lighting category).

Figure 13 shows how the shares change in response to higher prices in the Doubling Case. Relative to the reference case, the most noticeable differences are a further decline in incandescent lighting, more growth in CFL, less growth in halogen, more growth in electronic fluorescent lighting with controls, and greater penetration of the advanced technologies. Figure 14 illustrates the Doubling with Increasing Prices Case. The results are additional gains over the Doubling Case in CFL and advanced lighting technologies. In this case, incandescent lighting virtually disappears by 2020.

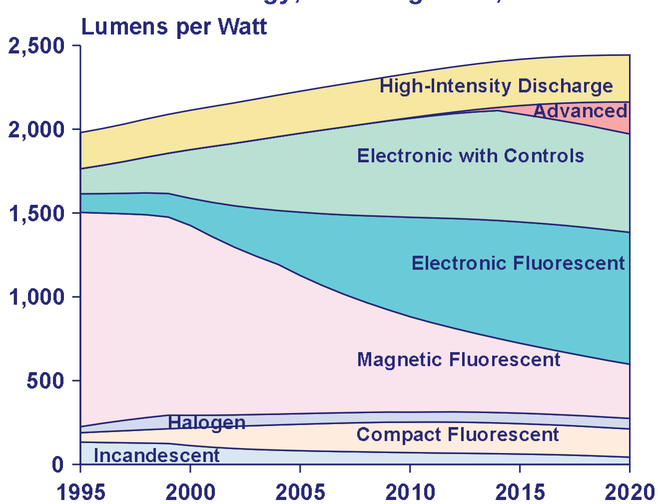
[23]The service demands illustrated include growth in commercial floorspace by region and building type. For the graphs shown here, no adjustments were made for the effects of elasticities (responses to price changes) or rebound (responses to efficiency changes) on the demand for service. Adjustments are made for these effects when the CDM computes energy consumption.

Figure 12. Lighting Service Demand by Technology, Reference Case, 1995-2020



Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A, ELAST98.D042098A, and ELAST98. D042098B.

Figure 13. Lighting Service Demand by Technology, Doubling Case, 1995-2020

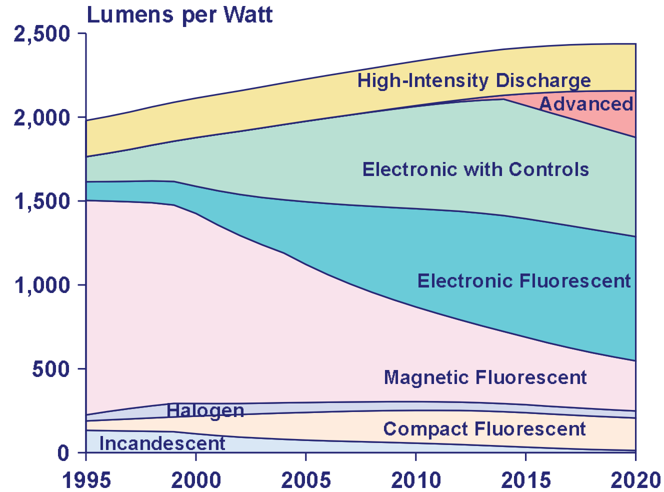


Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A, ELAST98.D042098A, and ELAST98. D042098B.

Summary

The residential and commercial energy modules of NEMS are rich in their representation of technologies. In general, multiple technologies are available for a given end use. Within general technology categories, from two to several versions of equipment are available at varying costs and energy efficiency levels. Although the specific techniques of technology choice employed by the two models are different, both choose equipment by evaluating the added costs of more efficient equipment relative to the stream of savings realized. Equipment standards are readily modeled in the NEMS framework by ensuring that the technology menus do not permit

Figure 14. Lighting Service Demand by Technology, Doubling with Increasing Prices Case, 1995-2020



Source: AEO98 National Energy Modeling System, runs AEO98B.D100197A, ELAST98.D042098A, and ELAST98. D042098B.

substandard efficiencies after the effective date of a standard.

The residential heat pump example illustrates several points about the NEMS representation of the residential energy equipment market, which are consistent with observed behavior in that market:

- The physical lifetime of equipment is a crucial determinant of the potential for near-term efficiency change, because equipment generally is replaced only as it wears out.
- Relatively high installed costs are a significant hurdle for adoption of new, more efficient equipment.
- The energy efficiency of purchased equipment increases when energy prices are higher.
- As residential building shell efficiency increases, there is a reduced incentive for the purchase of more efficient space heating and cooling equipment.

The commercial lighting example demonstrates the sensitivity of technology shares to prices. Across the price cases, aggregate lighting efficiency increases when electricity prices are higher. The efficiency gains occur when less efficient technologies are supplanted by purchases of more efficient technologies. The least efficient technologies, incandescent and halogen lighting, show reductions in market share as prices rise. Fluorescent lighting evolves away from magnetic ballasts and toward more efficient electronic ballasts in the reference case. As prices increase, the rate of evolution toward electronic ballasts increases. Also, the adoption of advanced technologies at the end of the forecast interval is noticeably affected across the price cases.

Appendix A
Lighting Technologies in *AEO98*

Table A1 presents the lighting cost and performance data for large office buildings for *AEO98*. These data include shares of service demand in the base model year (1992), efficiency, costs for installed fixtures with lamps, maintenance costs for replacement of lamps and other components, equipment life, years of availability, and the maturity level of the technology. The maturity level of the technology determines whether or not the capital and maintenance costs are subject to annual declines and the shape of the declines (the mature technology costs do not change annually).

Technology Groupings

The technology types have been grouped into four "technology classes," using the broad CDM definition of a technology. That is, lighting systems can compete within a technology class but not across classes. The first two CDM technology classes include filament-type lighting (ordinary incandescent lighting or halogen lighting), fluorescent lighting (either compact or 4-foot), as well as other filament-type lighting or advanced fluorescent technologies (e.g., scotopic lighting, which provides lumens at a wavelength that is optimal for human visual acuity). The third class is primarily 8-foot fluorescent lighting, and the fourth class is high-intensity discharge lighting but also includes a new technology (developed with funding from the U.S. Department of Energy), the sulfur lamp (which uses a sulfur element excited by microwave energy to produce light, which is sent to a long light tube for emission).

Effects of Federal Efficiency Standards

Fluorescent lighting systems using "standard" magnetic ballasts were phased out by the Energy Policy Act of 1990 (EPACT) but are included in the CDM technology data because they served a significant portion of base year lighting service demand. Consistent with the regulation, no purchases of standard magnetic ballasts are allowed during the modeling horizon. The manufacture of cool white bulbs in 8-foot and 4-foot lengths were also phased out by EPACT during 1994 (8-foot) or 1995 (4-foot).

Aggregation for Graphics

To make the graphical display of service demand shares visually tractable, the 33 lighting types were aggregated to 8 categories as follows:

- **Incandescent:** Includes only one technology, the 75-watt light
- **Halogen:** Includes the three halogen technologies
- **CFL:** Includes both compact fluorescent technologies
- **Magnetic Fluorescent:** Includes all standard and efficient magnetically ballasted fluorescent lighting, both 8-foot and 4-foot
- **Electronic Fluorescent:** Includes all electronically ballasted types that do not include controls or reflectors
- **Electronic Fluorescent with Controls:** Includes both controls and efficient reflector electronic ballasted lighting
- **Advanced:** Includes coated filament, hafnium carbide filament, scotopic, and electrodeless lighting
- **HID:** Includes all of Technology Class 4.

Table A1. Lighting Technologies and 1992 Base-Year Shares for Large Office Buildings

Description	Base-Year Share (Percent)	Efficacy (Lumens per Watt)	Capital Cost (1987 Dollars per Thousand Lumens)	Maintenance Cost (1987 Dollars per Thousand Lumens)	Life (Years)	First Available	Last Available	Maturity Level
Technology Class 1								
Incandescent: 1,170 lumens, 75 watts	3.9	15.6	34.02	10.72	12	1992	2040	Mature
CFL: 786 lumens, 14.6 watts	3.2	53.7	61.72	7.30	12	1992	2040	Adolescent
Halogen Infrared: 1,150 lumens, 55 watts	0.0	20.9	54.53	5.41	12	1995	2040	Adolescent
Coated Filament: 1,150 lumens, 25 watts	0.0	47.9	36.67	6.13	12	2010	2040	Infant
Hafnium Carbide Filament: 1,550 lumens, 23 watts	0.0	30.3	36.67	6.13	12	2005	2040	Infant
CFL: 1,200 lumens, 18 watts	0.0	66.67	44.14	6.21	12	1992	2040	Adolescent
Halogen: 1,300 lumens, 72 watts	2.9	18.06	56.24	22.45	12	1992	2040	Mature
Technology Class 2								
F40T12: Standard Magnetic Ballast	29.4	56.2	25.87	0.51	12	1990	1990	Mature
F40T12: Efficient Magnetic Ballast	8.9	65.2	17.94	0.38	12	1992	1995	Mature
F40T12: Efficient Magnetic Ballast Energy Saver	9.8	64.4	22.42	0.50	12	1992	2040	Mature
Halogen: 4,024 lumens, 209 watts	0.0	20.1	17.39	7.74	12	1993	2040	Mature
F40T12: Electronic Ballast Energy Saver	2.1	75.6	22.65	0.47	12	1992	2040	Adolescent
F32T8: Magnetic Ballast	0.1	74.2	19.83	0.48	12	1992	2040	Mature
F32T8: Electronic Ballast	10.9	84.2	21.60	0.51	12	1992	2040	Adolescent
F32T8: Electronic Ballast with Controls	3.3	120.3	29.27	0.51	12	1992	2040	Adolescent
F32T8: Electronic Ballast, Reflector	16.0	96.8	21.72	0.45	12	1992	2040	Adolescent
Scotopic Lighting	0.0	123	30.78	0.79	12	1995	2040	Infant
Electrodeless Lamp	0.0	152.8	24.47	0.34	20	2015	2040	Infant
Technology Class 3								
F96T12: Standard Magnetic Ballast	1.5	73.2	11.11	0.40	12	1990	1990	Mature
F96T12: Efficient Magnetic Ballast	4.0	75.7	6.36	0.31	12	1992	1994	Mature
F96T12: Efficient Magnetic Ballast Energy Saver	0.9	75.4	8.17	0.39	12	1992	2040	Mature
F96T12: Electronic Ballast	0.0	83.8	7.49	0.33	12	1992	1994	Adolescent
F96T12: Electronic Ballast Energy Saver	0.3	85.9	8.82	0.38	12	1992	2040	Adolescent
F96T12: Standard Magnetic Ballast High Output	0.0	70.6	7.19	0.27	12	1990	1990	Mature
F96T12: Efficient Magnetic Ballast High Output	0.0	73.6	5.18	0.27	12	1992	2040	Mature
F96T12: Electronic Ballast High Output	0.0	80	6.44	0.30	12	1992	2040	Adolescent
F96T12: Electronic Ballast High Output Energy Saver	0.0	80.9	7.44	0.46	12	1992	2040	Adolescent
Scotopic Lamp	0.0	123	25.83	0.79	12	1995	2040	Infant
Electrodeless Lamp	0.0	152.8	18.54	1.02	20	2015	2040	Infant
Technology Class 4								
Mercury Vapor	1.7	40.2	23.48	0.57	15	1992	2040	Mature
Metal Halide	0.7	69.6	11.79	0.28	15	1992	2040	Mature
High-Pressure Sodium	0.7	89.7	13.63	0.39	15	1992	2040	Mature
Sulfur Lamp	0.0	100	11.00	0.20	15	2000	2040	Infant

Source: AEO98 National Energy Modeling System, technology data.

The Importance of Location and Housing Type with Respect to Future Residential Sector Energy Use

by
John H. Cymbalsky

Households use energy to provide a wide variety of necessary services, such as space heating and cooling, water heating, and lighting, and to power a number of other appliances. The amount of energy consumed depends on such factors as the type, size, and location of the house; race and income level of the household; and the efficiency of both the equipment and the building shell. The purpose of this paper is to examine the importance of projected changes in housing patterns—in terms of location and housing type—with respect to residential sector energy consumption in the Annual Energy Outlook 1998 (AEO98) *reference case.*

Introduction

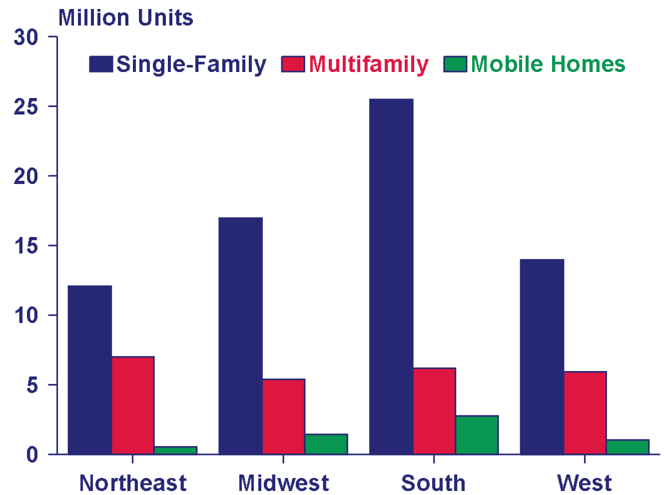
By 1995, the residential sector in the United States consisted of almost 100 million households, which are considered to be the primary residences for a population of more than 260 million people. Households use energy to provide a wide variety of services, from necessities such as heating and refrigeration to convenience items such as garage door openers and microwave ovens. The amount of energy consumed in households depends, in part, on how many and how often appliances are used, which in turn depends on the location, occupancy level, and size and type of residential structure.

This paper examines two important factors affecting energy consumption in households, namely, the type of future additions to the housing stock and their location. The reference case developed for the *Annual Energy Outlook 1998* (*AEO98*) projects a number of changes in housing trends and, as a result, residential energy consumption between 1995 and 2020. In order to gauge the importance of the projected shifts in U.S. housing trends, this analysis examines projections that were derived by fixing future household additions in proportion to their historical shares in the stock. The analysis examines the importance of changes in housing type and location separately and together. Because the focus of the analysis is energy consumed by households, all energy use is stated in terms of delivered energy, to remove the effects of efficiency changes in the electric utility sector; however, to illustrate the importance of other fuels in the generation of electricity, electricity-related losses are included in the graphs shown in the "Analysis Results" section.

Background

Of all the factors affecting energy demand in the U.S. residential sector, the types and locations of houses are the most important. Figure 1 shows the number of U.S. households in 1995 by type (single-family, multifamily, and mobile homes) and Census region. The South Census region, with more than 36 percent of the nearly 100 million households in the Nation, is the largest in terms of households.

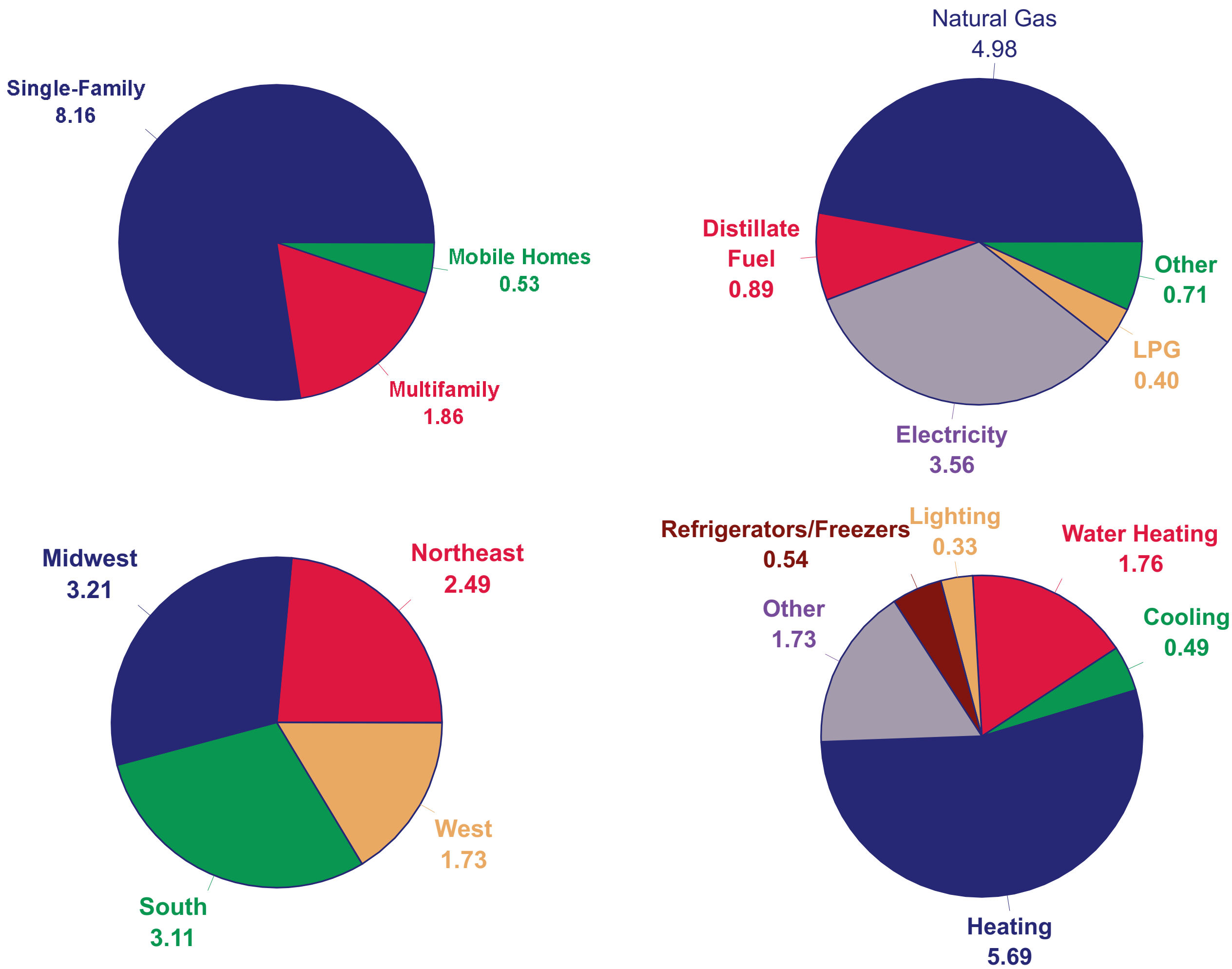
Figure 1. Households by Type and Census Region, 1995



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Housing characteristics data for 1997 are available from web site www.eia.doe.gov.

Single-family homes are most prevalent, accounting for more than two-thirds of the stock and consuming more than three-quarters of the delivered energy used in the residential sector (Figure 2). These homes tend to be, on average, larger than the other types in terms of both physical size and number of occupants, requiring more energy for cooling, lighting, and space and water heating. Multifamily units, on the other hand, account for 25 percent of all housing units but consume only 17 percent of the delivered energy used in the sector. Small dwelling size, fewer occupants per unit, and a higher

Figure 2. Residential Sector Delivered Energy Consumption, 1995
(Quadrillion Btu)



Note: Totals may not be equal due to independent rounding.
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

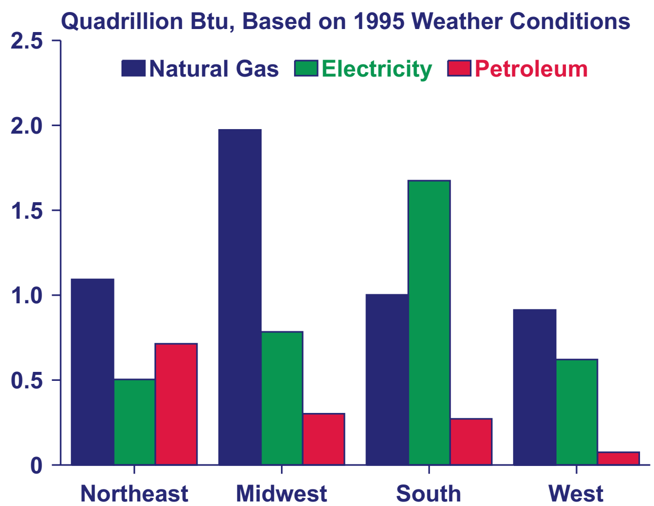
percentage of units heated with electricity, which is more efficient on a delivered basis, all contribute to energy consumption that is less than its share of the housing stock. Mobile homes, which use liquefied petroleum gas (LPG) more often than other homes and are concentrated in the South Census region, account for 6 percent of the housing stock and consume 5 percent of all residential energy.

The climate, particularly as it relates to demand for space heating, has a significant influence on energy consumption. Although natural gas has far fewer uses within the home than does electricity, its consumption—47 percent of delivered energy in the residential sector—is considerably higher, primarily because of the high level of demand for space heating, which makes up 54 percent of all delivered energy use in the sector (Figure 2). Energy consumption in the Northeast and Midwest Census regions, which hold slightly less than half (44 percent) of all U.S. households (Figure 1), accounted for 54 percent of the U.S. total in 1995 (Figures 2 and 3), further demonstrating the importance of space heating in the residential sector.

Because climate plays such a significant role in determining the types and amounts of energy consumed from year to year, it is important to relate "normal" (30-year average) weather conditions to those experienced in 1995 in the four Census regions. Table 1 lists the 1995 and 30-year average heating and cooling degree-days[1] for each Census region. The number of heating and cooling degree-days has a direct effect on the amount of fuel consumed for space heating and cooling. For example, if the trend in housing is away from the northern climates toward the southern climates, then the amount of fuel needed for heating decreases and the amount of fuel needed for cooling increases. Table 1 shows that a shift in housing to the South from the Midwest yields half as many heating degree-days, but two and a half times as many cooling degree-days.

[1]A heating degree-day is the difference between the mean temperature for a 24-hour period and 65°F when the mean is below 65°F. A cooling degree-day is the difference between the mean temperature for a 24-hour period and 65°F when the mean is above 65°F.

Figure 3. Residential Sector Delivered Energy Consumption by Major Fuel and Region, 1995



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

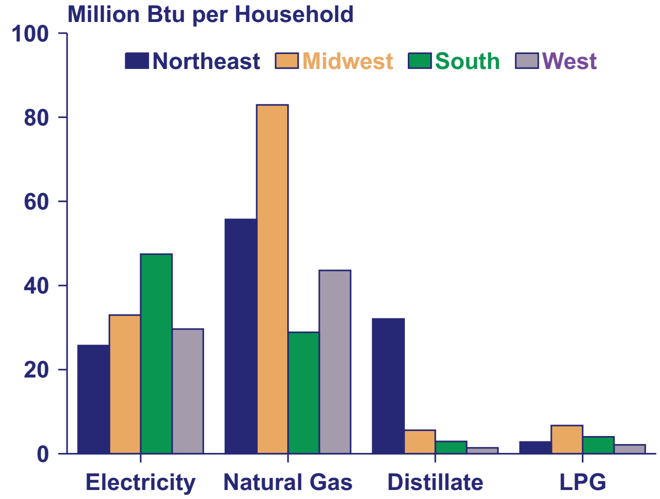
National Energy Modeling System (NEMS) Analytic Approach

Given the importance of the factors described above, the NEMS residential module was developed to account for changes in fuel types, end-use efficiency, regionality, and construction patterns for the different housing types. Accordingly, the NEMS residential module represents 7 fuel types, 13 end uses, 9 Census divisions, and 3 building types.[2]

Demand for Energy Services

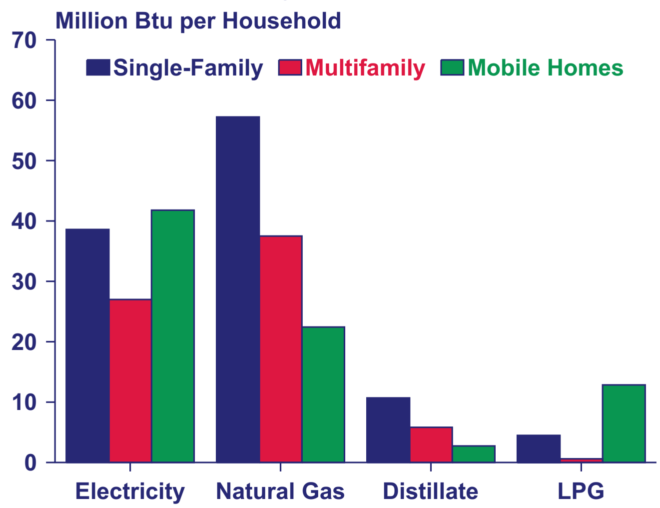
The energy required for end-use services can vary widely, depending on the type and location of household. Therefore, it is imperative that the energy intensities (the amount of delivered energy used per household) associated with the different housing types and regions be accounted for. The base year (1993) intensities for energy services and fuel types by Census region and housing type are based on the Energy Information Administration's (EIA's) Residential Energy Consumption Survey (RECS). RECS provides NEMS with data on the number of households, number of appliances, and energy use associated with specific appliances. Figures 4 and 5 show 1995 energy use per household for the major fuels both by Census region and

Figure 4. Household Delivered Energy Use by Fuel and Region, 1995



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 5. Household Delivered Energy Use by Fuel and Housing Type, 1995



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 1. 1995 and 30-Year Average Heating and Cooling Degree-Days per Year by Census Region

Region	Heating Degree-days		Cooling Degree-Days	
	1995	30-Year Average	1995	30-Year Average
Northeast	6,021	6,061	726	609
Midwest	6,706	6,499	940	809
South	2,838	2,852	2,118	2,021
West	3,374	3,830	884	831

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[2]For detailed information about the NEMS residential module, see Energy Information Administration, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M067(98) (Washington, DC, January 1998), also available electronically in portable document format (PDF) at EIA*s ftp site: *ftp://ftp.eia.doe.gov/pub/model.docs/mo6798.pdf*.

by housing type. By averaging the energy consumption over all households, regardless of whether they use the fuel or not, the relative importance of each fuel can be determined for the different regions and building types.

To estimate future energy demand, the NEMS residential module employs a stock / vintage approach, which projects the numbers and efficiency of major household appliances over time. As older appliances in the stock are replaced by newer, more efficient models, energy use per appliance decreases, all else being equal.

The stock of energy-using equipment is a function of the saturation levels for the various end-use services. Of the major end uses represented in NEMS, only central air conditioning and clothes drying are assumed not to be fully saturated. In other words, ownership of these appliances has been increasing and is projected to continue to increase over time. All other major end uses (heating, water heating, cooking, refrigerators, and freezers) are assumed to be fully saturated at their respective 1993 levels for new and existing housing, since their respective ownership levels have been stabilized.

Once the amount of equipment needed to meet the demand for the entire housing stock is known, estimates of energy consumption can be calculated. Some services, such as space and water heating, can be furnished by more than one fuel type. In these cases, decisions about fuel type must be made before energy use can be estimated. Future energy prices, which are determined by the interaction of all the NEMS supply and demand modules, will affect fuel types, energy efficiency, and the intensity at which fuel is used in future years. It is assumed that rising real energy prices over time will lead to decreasing energy intensity through improved equipment and building shell efficiency and changes in behavior, such as adjusting thermostat levels.

Efficiency of Energy Services

Several factors contribute to the efficiency of the appliance stock over time, including energy prices, Federal efficiency standards, turnover rates, the relative intensities at which appliances are used, and the purchase costs of competing technologies. Because market characteristics cause investments in energy efficiency to be evaluated at high implicit discount rates,[3] energy prices tend to have a relatively small impact on consumer choice with regard to the efficiency of purchased appliances. Many barriers in the residential market contribute to high implicit discount rates, including short occupancy periods, renter-occupied units (currently around 35 percent of the stock), emergency equipment replacements, and general inertia regarding equipment purchases. Generally speaking, appliance efficiency is higher in owner-occupied single-family households, for which total energy requirements are greater. For example, a large single-family owner-occupied home in the upper Midwest would be more likely to invest in an energy-efficient gas furnace than would a rental unit in the deep South.

Analysis Results

There are many factors that influence the forecast for future residential energy consumption in the United States, including:

- Housing and population elements
- Technology characteristics and availability
- Market forces.

The number of occupied households plays a key role in determining residential sector energy use. In the forecast, occupied households are a function of housing starts, which are a function of economic activity and population trends. This paper examines the energy consequences of several cases in which housing starts are altered to control for the effects of changing housing patterns by both Census region and structure type, using the *AEO98* reference case as a point of comparison.

Housing and Population Elements

To better understand the effects of housing and population changes on residential energy use in the *AEO98* reference case, it is necessary to examine household formation. The NEMS residential module bases its estimate of occupied households on data from EIA's 1993 RECS. As the levels of economic activity (i.e., income) and population increase over time, housing starts—the key economic indicator in the housing sector—increase as well. This variable serves as the key driver in the NEMS residential module.

To isolate the effects of shifts in location and type of house, a control case was examined that adds future households to the stock in the same proportion that they represent in the existing stock, leaving the level of total additions unchanged from that in the *AEO98* reference case. To establish the relative importance of regional shares and housing types in terms of future U.S. residential energy consumption, the regional shares and housing types were fixed at their 1999 reference case levels. Three cases were examined:

- *Case 1*: Fix housing starts by region to their 1999 reference case shares, allowing the number of starts and the building types to vary as they do in the reference case
- *Case 2*: Fix housing starts by type at their 1999 reference case shares, allowing the number of starts and their regional distribution to vary as they do in the reference case

[3] See A. Jaffe and R. Stavins, "The Energy-Efficiency Gap, What Does It Mean?" *Energy Policy*, Vol. 22, No. 10 (October 1994), p. 804.

• *Case 3*: Fix housing starts by type and by region at their 1999 reference case shares, allowing the number of starts to vary as they do in the reference case.

For all three cases, 1999 served as the base year, with 2000-2020 serving as the analysis period.

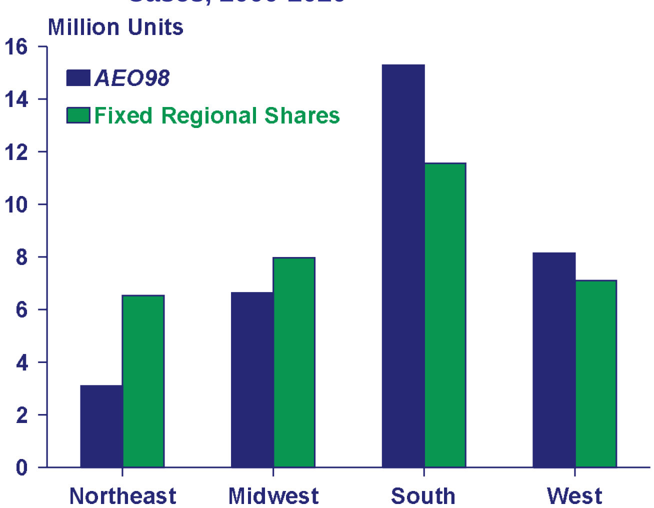
Case 1: Housing Stock with Fixed Regional Shares

In this sensitivity case, all housing starts from 2000 to 2020 were set at the *AEO98* reference case levels, but the regions in which the houses are built were representative of the stock as it existed in 1999. This case serves to establish the importance of the regional migration of the population assumed in the *AEO98* reference case forecast.

Figure 6 shows additions of new households in the reference case and in the sensitivity case with static regional housing shares. The regional trend in housing is clear; the shift is away from the northern climate regions (Northeast and Midwest Census regions) and toward the south and western climate regions (South and West Census regions). In this sensitivity case, the number of households added in the Northeast Census region through 2020 would be more than double the number projected in the *AEO98* reference case. The South Census region, which is projected to show the strongest growth in the *AEO98* reference case, would be the most adversely affected.

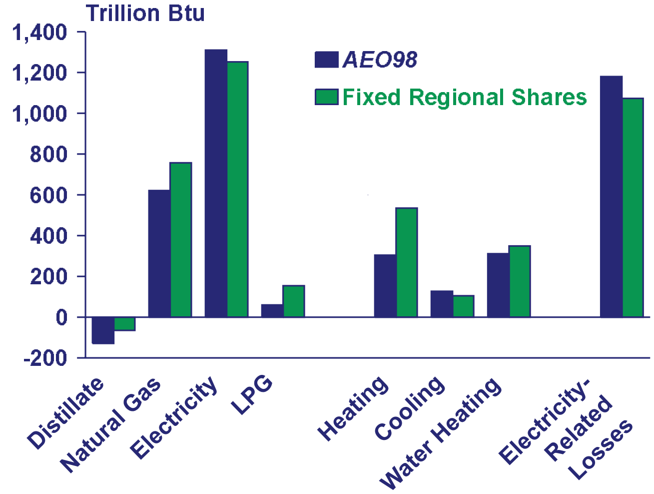
Given the shift away from the colder regions of the country in the *AEO98* reference case, it is intuitive that space heating, and the fuels associated with it, would be most affected in the case with the housing stock at fixed regional shares. Figure 7 shows changes in delivered energy consumption by fuel and end use in the two

Figure 6. Household Additions by Region in the Reference and Fixed Regional Shares Cases, 2000-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 7. Change in Residential Delivered Energy Consumption by Fuel and End Use and Electricity-Related Losses in the Reference and Fixed Regional Shares Cases, 2000-2020



Note: Electricity-related losses were calculated at 2.20 Btu lost per Btu of electricity delivered in 2000 and 1.88 Btu lost per Btu of electricity delivered in 2020.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

cases, as well as the change in energy losses associated with electricity generation, transmission, and distribution (i.e., electricity-related losses). All the major space heating fuels—natural gas, distillate, and LPG—would increase in importance if housing were constructed according to the regional share of households in 1999. Electricity, which is used in virtually every home, regardless of region, shows little variation between the two cases.

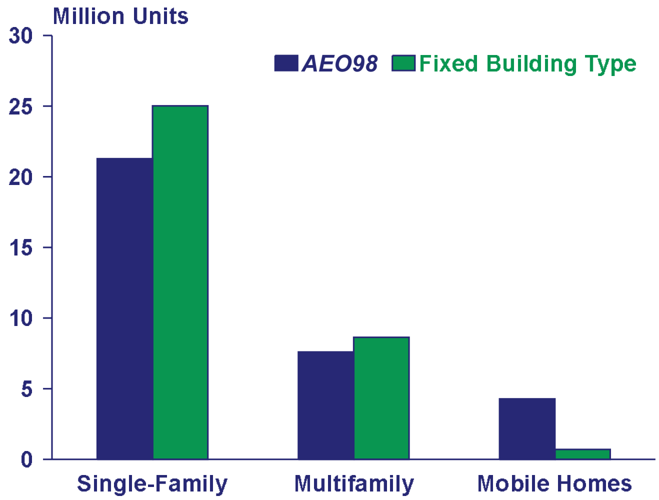
Case 2: Housing Stock with Fixed Building Types

For this sensitivity case, as in case 1, housing starts in 2000-2020 were set at the levels projected in the *AEO98* reference case, but the types of homes built were set at the proportions that existed in the 1999 stock. This case serves to isolate the energy effects of the projected shift in housing types in the *AEO98* reference case.

Figure 8 shows additions of new households in the reference case and in the sensitivity case with fixed building types. The figure shows the projected increase in importance of mobile homes in the housing stock, relative to the other types of housing, in the *AEO98* reference case. The number of mobile homes added through 2020 in the reference case is nearly six times that in the sensitivity case. Additions of single- and multifamily households are correspondingly higher in the sensitivity case.

The type of house built has a direct affect on fuel consumption, because the different housing types use fuels in different proportions. For instance, mobile homes

Figure 8. Household Additions by Type in the Reference and Fixed Building Type Cases, 2000-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

tend to use LPG more frequently for space heating than do either single-family or multifamily structures. Given the variation of fuel shares among the three housing types, fuel consumption in the housing stock with fixed building types case should vary from that projected in the *AEO98* reference case.

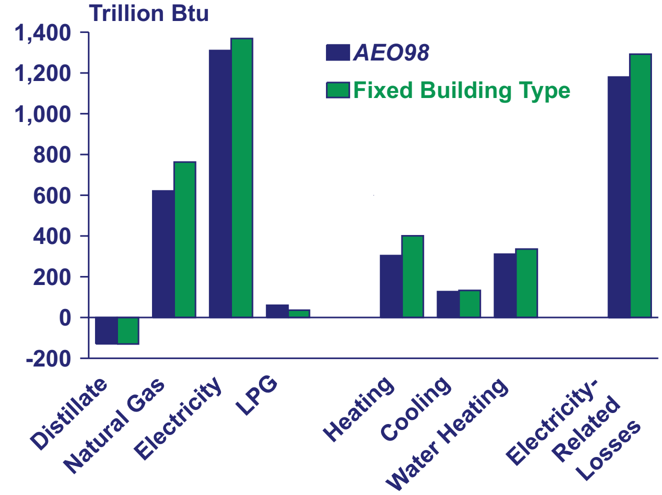
Figure 9 shows the change in residential energy consumption from 2000 to 2020 by fuel and end use, as well as the change in electricity-related losses, in the reference and sensitivity cases. Given the shift toward more mobile homes in the reference case, LPG consumption is lower in the fixed building types sensitivity case, whereas natural gas and electricity consumption is higher. Distillate use changes little from the *AEO98* reference case, because its use is dependent on region rather than building type. In terms of end-use consumption, space conditioning increases in this case, because the housing stock, on average, is larger in terms of physical size, requiring more fuel to heat and cool the larger floor space.

Case 3: Housing Stock with Fixed Regional and Building Type Shares

The third sensitivity case combined the assumptions of the first two cases. This case, therefore, factors out all the regional and housing type shifts that affect residential sector energy consumption in the *AEO98* reference case.

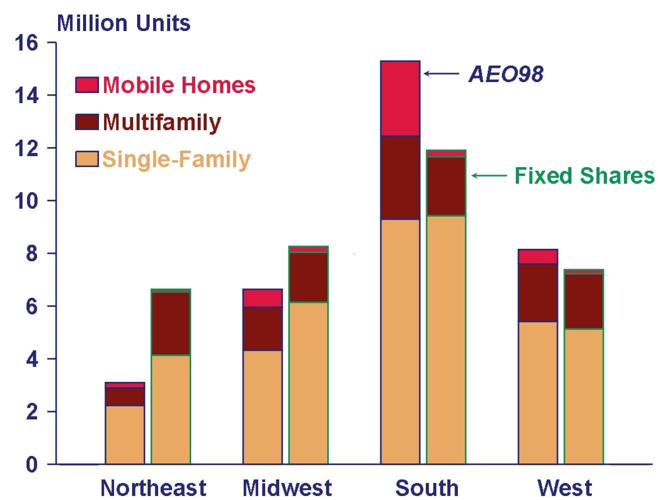
Figure 10 shows additions of new households from 2000 to 2020 by Census region and housing type in the reference and sensitivity cases. The largest source of positive change in terms of household additions in the *AEO98* reference case is in the South Census region and, in particular, in multifamily and mobile homes. The numbers of single- and multifamily homes in the Northeast are

Figure 9. Change in Residential Delivered Energy Consumption by Fuel and End Use and Electricity-Related Losses in the Reference and Fixed Building Type Cases, 2000-2020



Note: Electricity-related losses were calculated at 2.20 Btu lost per Btu of electricity delivered in 2000 and 1.88 Btu lost per Btu of electricity delivered in 2020.Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 10. Household Additions by Type and Region in the Reference and Fixed Shares Cases, 2000-2020

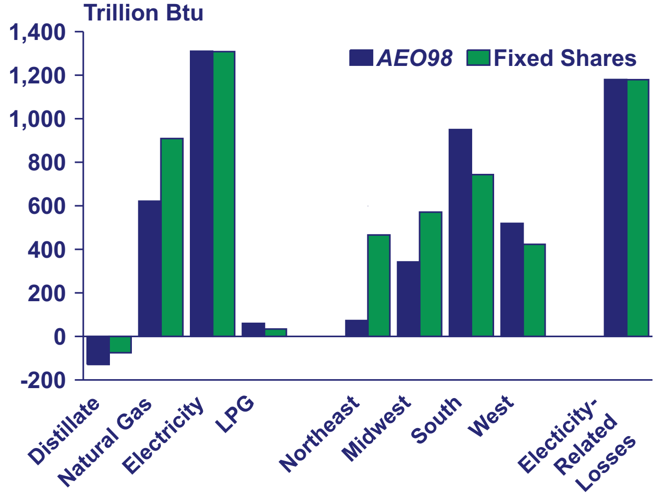


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

much smaller in the *AEO98* reference case than in the fixed shares sensitivity case.

The energy implications of this sensitivity case basically combine those of the first two cases. Electricity consumption in this case is identical to that in the *AEO98* reference case (Figure 11), indicating that in the *AEO98* reference case, the decrease in electricity consumption related to shifts in housing types is offset by the increase related to shifts in the regional distribution of housing

Figure 11. Change in Residential Delivered Energy Consumption by Fuel and Census Region and Electricity-Related Losses in the Reference and Fixed Shares Cases, 2000-2020



Note: Electricity-related losses were calculated at 2.20 Btu lost per Btu of electricity delivered in 2000 and 1.88 Btu lost per Btu of electricity delivered in 2020.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

starts. Natural gas consumption, on the other hand, shows a relatively large increase in this case relative to the *AEO98* reference case. With the shares of housing starts by both housing type and Census region fixed at 1999 stock levels, natural gas consumption increases as more homes with relatively high natural gas intensities are added in cold climates than are projected in the *AEO98* reference case.

Conclusions

By examining trends in the major driver of residential energy consumption—housing starts—the importance of both location and type of household with respect to projected residential energy consumption can be quantified. This analysis has shown that for the *AEO98* reference case, the location (i.e., climate) of the housing stock has a larger impact on residential sector delivered energy consumption than does the type of house. The projected shift in housing starts from the Northeast and Midwest Census regions to the South Census region in the *AEO98* reference case has the greatest effect on the fuels used for space heating—specifically, natural gas and distillate. The type of house built, while having less impact on delivered energy consumption than location, still affects fuel choice. The shift away from single-family homes toward mobile homes in the *AEO98* reference case dampens the potential for natural gas, because mobile homes tend to use LPG and electricity as a space heating fuel more often than do single-family homes.

Measures of Oil Import Dependence

by
James M. Kendell

Measures of oil import dependence or vulnerability can be divided into physical and economic dimensions. Physical measures of dependence have been used most frequently to assess the level of U.S. needs for imported oil. However, measures of import vulnerability—whether physical or economic—are likely to be more useful than measures of dependence in assessing U.S. energy security.

Introduction

In 1977 the United States imported a record 46.5 percent of the oil it needed to fuel its vehicles, heat its homes, and run its industry. In reaction to rising prices and such high levels of imports, the Nation established a Department of Energy, spent billions of dollars on researching and finding new sources of energy supply, and redesigned its cars, houses, and factories to make them more energy efficient. Yet last year, when the United States broke its 20-year record for oil import dependence, few voices were heard noting, let alone decrying, the high levels of imports. In the interim, analysts and policymakers had learned that simple measures of physical dependence do not tell the whole story of oil imports.

This paper explores the meaning and value such measures as "net imports as a percentage of product supplied" when used as indicators of energy security. While the limits of this particular dependence measure are now generally understood, policymakers still need good measures of energy security to tell them (and the voters) when U.S. vulnerability is growing as a result of increased oil imports. In choosing oil security measures, one of the most important distinctions is between oil import dependence and oil import vulnerability. Knowing that the Nation imports 2 percent or 50 percent of its oil tells how *dependent* it is, but not how *vulnerable* it is to oil price shocks and to oil supply disruptions. The distinction between dependence and vulnerability has been made for years by oil analysts, but with the United States poised to move beyond 50 percent dependence, it is worth drawing the distinction once again.

A variety of measures have been used over the years by the Energy Information Administration (EIA) to gauge the significance of oil imports (Table 1). In addition, a comprehensive series of measures was used by the U.S. General Accounting Office (GAO) in a recent study of energy security. The GAO measures are notable for their attempt to cover the range of physical and economic aspects of both import dependence and vulnerability. The GAO measures were developed in consultation with EIA and other offices in the Department of Energy.

Physical Dependence

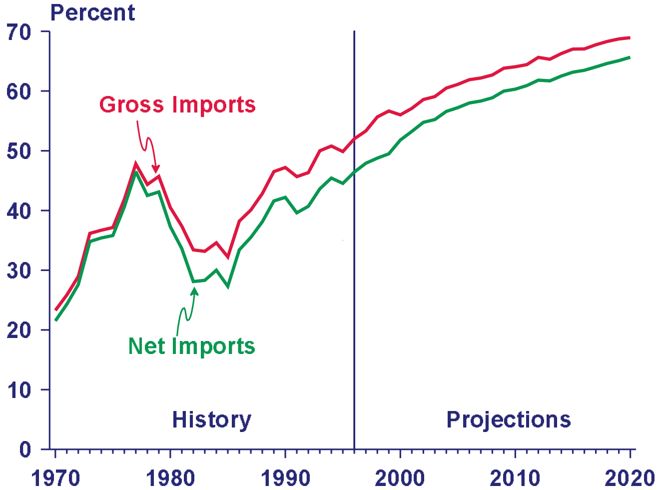
The EIA has regularly published a measure of oil import dependence since 1979. In March 1979, gross oil imports as a percentage of product supplied began to appear as an ongoing graph in the *Monthly Energy Review*. The gross import dependence percentage had risen steadily from 1967 through 1977 and appeared ready to break the 50 percent barrier (Figure 1). Consequently, the gross percentage was published in EIA's leading publication, the *Monthly Energy Review*. (At the time, gross imports were labeled "direct" imports; today EIA uses the term "total" imports for gross imports.)

The trouble with using gross imports in the numerator of this measure is that it overstates U.S. dependence on imported oil. For, if all else were equal, rising exports would mean a higher percentage of gross oil import dependence. In the 1970s, when oil exports were relatively small, the distinction between gross and net imports was minor. Exports averaged only 267,000

Table 1. Oil Import Dependence and Vulnerability Measures

Measure	Physical Dimension	Economic Dimension
Dependence	Import Share of Product Supplied	Value of Imports Import Value as Percent of Total Product Value
Vulnerability	Percent of World Exports Days Supply of Stocks Surge Capacity Oil Used in Transportation Oil Used per Capita	Consumption per Dollar of GDP Expenditures per Dollar of GDP

Figure 1. Petroleum Imports as a Percentage of Products Supplied, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

barrels per day, with Canada, Japan, and Mexico as major recipients of U.S. oil. But by 1982 exports had more than tripled to 815,000 barrels per day, with the Virgin Islands, Puerto Rico, the Netherlands, and Canada as major export partners. Thus, in December 1982, the *Monthly Energy Review* began to publish net imports as a percentage of product supplied.

Even though the EIA stopped publishing gross imports as a percentage of products supplied in 1982, the American Petroleum Institute (API) continued to use this measure. API argued that there was no market for the petroleum products exported by the United States, and that the exports were irrelevant to a dependence calculation. The counter argument is that some U.S. exports could easily be consumed domestically. Indeed, more than half of U.S. oil exports in 1997 were crude oil, natural gas liquids, gasoline, gasoline blending components, jet fuel, and distillate fuel oil—all marketable liquids within the United States.

In 1993, gross oil imports reached 50 percent of product supplied, exceeding the previous record set in 1977 and even prompting calls for legislative action. Since then gross oil imports have grown, and they are expected to continue growing over time.

In August 1995 the EIA made its most recent change to the publication of oil import dependence numbers, by adding "gross imports as a percentage of product supplied" alongside its publication of "net imports as a percentage of product supplied" in the *Monthly Energy Review*. An accompanying note stated that: "EIA believes that the net-imports definition gives a clearer indication of the fraction of oil consumed that could not have been supplied from domestic sources and is thus the most appropriate measure."[1]

As noted above, in 1997 the United States exceeded its 20-year record for net oil imports as a percentage of product supplied.[2] The Nation imported almost 48 percent of its net petroleum supply in 1997, compared with the previous record of 46.5 percent in 1977. The *Annual Energy Outlook 1998* (*AEO98*) reference case projects that net dependence will exceed 50 percent in 2000 and rise to 66 percent in 2020.[3]

The *AEO* began to publish an oil import dependence measure in 1996. As might be expected, the measure chosen was net imports as a percentage of product supplied. Until then, *AEO* users had to calculate their own measures, which led to some interesting questions. More than once, EIA was called to explain why it was showing import dependence of over 70 percent in 2015. It is possible to reach such high numbers, but only by doing the calculation on a gross basis with British thermal units (Btu) rather than barrels. The argument for doing a net, rather than gross, calculation is stated above. The argument for using barrels, rather than Btu, is that a physical measure of dependence (or vulnerability) ought to use physical units, rather than a heat value. After all, producers and consumers typically sell and buy oil in barrels, not in Btu.

When the EIA began publishing measures of oil import dependence in 1979, the *Monthly Energy Review* also began publishing a graph of dependence on oil imports specifically from the Organization of Petroleum Exporting Countries (OPEC), because OPEC was widely viewed as controlling the world oil price. The graph showed gross imports from OPEC as a percentage of U.S. product supplied (although gross and net imports in this case are virtually the same). A few years later, in 1982, the *Monthly Energy Review* also began publishing a graph showing dependence on Arab OPEC oil imports, because the Arab members of OPEC had stopped exporting oil to the United States in 1973-1974. In 1982 the calculations for OPEC and Arab OPEC were changed to net imports as a percentage of U.S. product supplied, just as the total dependence calculation had been switched to net imports. Both the OPEC and Arab OPEC net percentage peaked in 1977, the same year of the overall peak.

In 1995, in the wake of the Iran-Iraq war, the Persian Gulf war, and strategic thinking about the vulnerability of oil exports from the Persian Gulf, the *Monthly Energy Review* stopped publishing OPEC and Arab OPEC percentages and switched to imports from the Persian Gulf

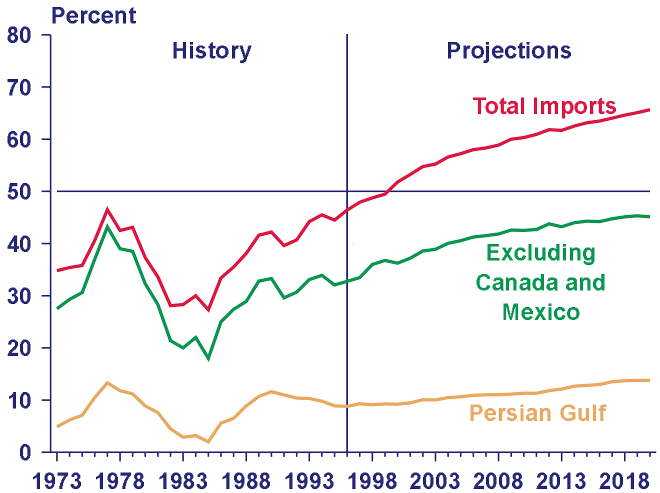
[1]C.W. Skinner, "Measuring Dependence on Imported Oil," in Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/08) (Washington, DC, August 1995), p. i.

[2]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(98/02) (Washington, DC, February 1998), Table 1.8, p. 15.

[3]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

region as a percentage of product supplied.[4] Like the other measures, that percentage peaked at more than 13 percent in 1977. The 1977 peak is not projected to be exceeded until 2017, according to the AEO98 (Figure 2). By 2020 the Persian Gulf is expected to supply 14 percent of U.S. consumption.

Figure 2. Net Petroleum Imports as a Percentage of Products Supplied, 1973-2020



Sources: **History:** Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997); and EIA, *Monthly Energy Review*, DOE/EIA-0035(98/02) (Washington, DC, February 1998). **Projections:** EIA, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

Other variations of such dependence measures have also been used or suggested. One refinement could be to add or subtract the net oil stock change to net petroleum imports in the numerator, on the theory that imports to build stocks are not being consumed.[5] On an annual basis, such a refinement would make little difference, but it could make a substantial difference on a monthly basis.

Another, more significant variation would exclude Canada and Mexico from the numerator (Figure 2).[6] Canadian and Mexican supplies are closer to the United States and are, in theory, less vulnerable to interruption than supplies that must travel long distances on the open sea. By this measure, dependence on other imports does not reach the 1977 peak until 2012.

Physical Vulnerability

While measures of oil import dependence may be of some interest, they offer a limited guide to energy security. At 48 percent net dependence on imported oil this year, is the United States any less secure than it was at 42 percent in 1990, 43 percent in 1979, or 35 percent in 1974? Other countries, including Japan, Sweden, and Spain, have managed to grow and prosper despite almost complete dependence on imported oil.

Oil dependence does not necessarily mean that the United States is vulnerable to an oil disruption. If the world oil supply came from many small producers and one of them suddenly stopped exporting oil, it would have little effect on U.S. and world supplies and prices, even at a high rate of U.S. dependence. The distinction between dependence and vulnerability suggests that concentration is a key factor in the security of our oil supply.

Concentration of world oil production in the Persian Gulf is one of the measures used by the GAO in its December 1996 report, *Energy Security: Evaluating U.S. Vulnerability to Oil Supply Disruptions and Options for Mitigating Their Effects*.[7] The Persian Gulf percentage of world oil production, which declined from 1976 to 1985, has been generally rising since then and is expected to continue rising through 2020, according to the *AEO98* (Figure 3).

Perhaps more important than the Persian Gulf share of world oil production is its share of the world export market: if most Persian Gulf oil production were consumed in the Persian Gulf, a supply disruption would not directly affect U.S. vulnerability. In fact, however, if those exports were cut off, the effect would be immediate and direct, because a disruption in one part of the world quickly affects supplies and prices in the rest of the world. The peak for Persian Gulf oil exports as a percentage of world oil exports was in 1974, when they accounted for more than two-thirds of the oil traded in world markets. The Persian Gulf share of world oil exports has risen since the oil price collapse of the mid-1980s, but it is not expected to surpass the 1974 level until after 2020. A graph of "Persian Gulf Share of Worldwide Oil Exports" appeared in the *AEO* beginning with *AEO97*.

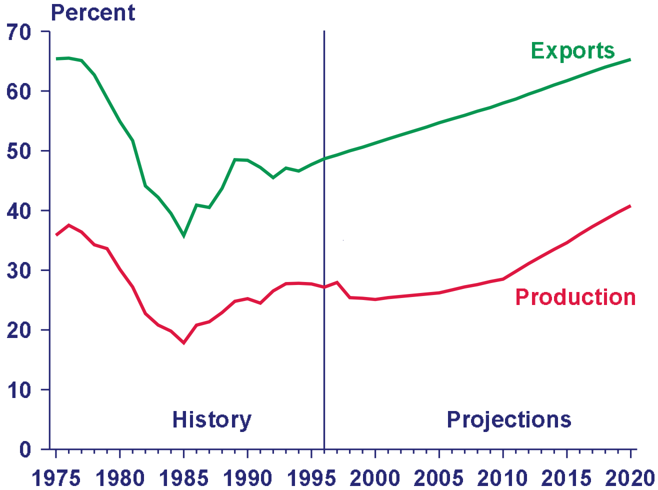
[4]The *Annual Energy Review* continued to publish the OPEC percentage in 1997. See Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Table 5.7, p. 149.

[5]C.W. Skinner, "Measuring Dependence on Imported Oil," in Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(95/08) (Washington, DC, August 1995), p. iii.

[6]B.H. Bawks, "The Outlook for U.S. Import Dependence," in Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1996*, DOE/EIA-0607(96) (Washington, DC, August 1996), p. 83.

[7]U.S. General Accounting Office, *Energy Security: Evaluating U.S. Vulnerability to Oil Supply Disruptions and Options for Mitigating Their Effects*, GAO/RCED-97-6 (Washington, DC, December 1996).

Figure 3. Persian Gulf Share of World Oil Production and Exports, 1975-2020



Sources: **History:** Energy Information Administration (EIA), *International Petroleum Statistics Report*, DOE/EIA-0520 (97/07) (Washington, DC, July 1997); and EIA, *Monthly Energy Review*, DOE/EIA-0035(98/02) (Washington, DC, February 1998). **Projections:** EIA, Office of Integrated Analysis and Forecasting.

In 1977 two of the top five U.S. oil suppliers were Persian Gulf countries (Iran and Saudi Arabia), and two more were also in the Eastern Hemisphere (Libya and Nigeria). But 20 years later, only two of those Eastern Hemisphere suppliers, Saudi Arabia and Nigeria, remained in the top five. In 1997, three of the top U.S. oil suppliers were in the Western Hemisphere (Venezuela, Canada, and Mexico).

Even as the world and the United States have moved away from dependence on Persian Gulf oil, however, the reliance on large suppliers has increased. In 1977 the top five U.S. oil trading partners provided the United States with the equivalent of 25 percent of product supplied (on a gross basis). In 1997 the top five provided the United States with 36 percent of product supplied. Over these 20 years gross import dependence has increased by 5 percentage points, whereas dependence on the top five suppliers has grown by 11 percentage points.

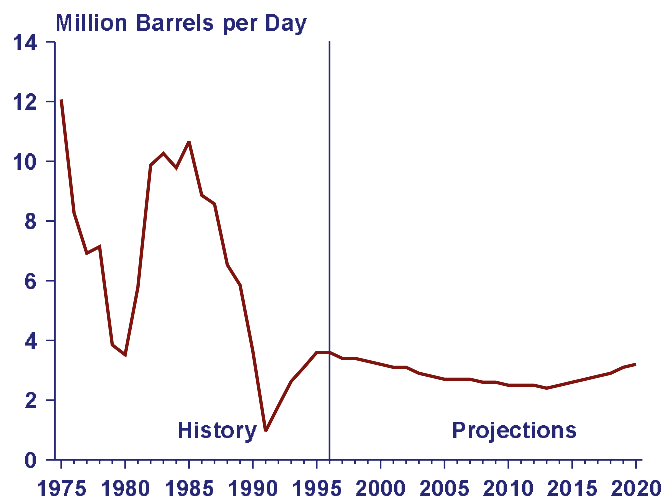
Emergency, noncommercial inventories are one strategy to cope with supply disruptions. In 1974 the United States experienced its most significant supply interruption with the cutoff of about 18 million barrels per day, or about 55 percent of the world export market. During that disruption, the world oil price tripled, from about $4 a barrel to about $12 a barrel. In 1990, the Iraqi invasion of Kuwait meant the loss of 4.3 million barrels of oil production per day, or about 13 percent of the world export market. This led to a doubling in the world oil price from July to October 1990, from about $16.50 to about $33 a barrel.

By 1990 the United States and other governments had created emergency stockpiles of oil as a buffer against disruption. The invasion of Kuwait showed that the United States and other governments were willing to use their stockpiles. A noncommercial measure, "Days of Net Petroleum Imports in the Strategic Petroleum Reserve," is published in the *Annual Energy Review*. It shows that the U.S. Strategic Petroleum Reserve (SPR) peaked at 115 days of supply in 1985 and has now declined to 63 days. Assuming that the SPR does not expand or contract, coverage will decline to 35 days in 2020 as consumption grows.

Combining noncommercial and commercial stocks provides a somewhat broader measure of the ability of inventories to respond to supply disruptions. Since 1985, available commercial stocks in the Organization for Economic Cooperation and Development (OECD) countries have fluctuated between 25 and 30 days of supply. Assuming that commercial pressures keep stockpiles from expanding, while consumption continues to grow, the supply would slip to 20 days in 2020.[8]

Besides stockpiles, surge capacity or excess world production capacity is another source of supply. Historically, excess capacity has responded primarily to prices, building up during periods of high prices and declining during periods of low prices. A buildup occurs during a high-price period such as the early 1980s, as consumers conserve and producers rush to find more oil and cash in on high prices. If oil prices remain at their current moderate levels through 2020, excess capacity can be expected to decline from 3.4 to 2.4 million barrels per day in 2013, before rising to 3.2 million barrels per day in 2020[9] (Figure 4).

Figure 4. World Excess Oil Production Capacity, 1975-2020



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[8]A similar measure, "Available Stocks in Days of World Consumption," used in the GAO study is no longer available.

[9]This measure was used in the GAO study.

From 1992 to 1994, EIA combined some of these vulnerability indexes to create a composite "Index of OPEC Dependence." At first named the "Vulnerability Index," this composite measure was published in the *International Energy Outlook*.[10] The composite index was for three measures: the percentage of world oil demand supplied by OPEC, OECD oil stock levels, and excess OPEC crude oil production capacity. The index was a weighted average of 50 percent for excess capacity, 30 percent for OPEC market share, and 20 percent for available stocks. Each of the variables was given a weight of 100 when at the greatest dependence and 0 at the least dependence. The advantage of combining the three measures is that it allows the measure of OPEC market power to be mitigated by measures of stocks and excess capacity.

In 1994 the index showed that dependence on OPEC was expected to increase and, by 2010, to be close to the levels of the early 1970s. If the same index were calculated with *AEO98* projections, the high 1973-74 levels probably would not be reached until after 2020, primarily because of the significant increases in non-OPEC oil production that have been projected since 1994.

In addition to supply-side measures of oil vulnerability, demand-side measures have been constructed. In the transportation sector, the GAO study used "Oil as a Percentage of Total Energy Used in Transportation." Dependence on oil in the transportation sector is projected to decline from about 97 percent at the present time to about 95 percent in 2020, as alternative fuel consumption grows, with compressed natural gas leading the way. Another demand-side measure is oil consumption per capita, a measure that the EIA has occasionally published. By this measure, Americans consumed 26 barrels of oil each in 1970 and again in 1997, with a projected increase to 28 barrels each in 2020.

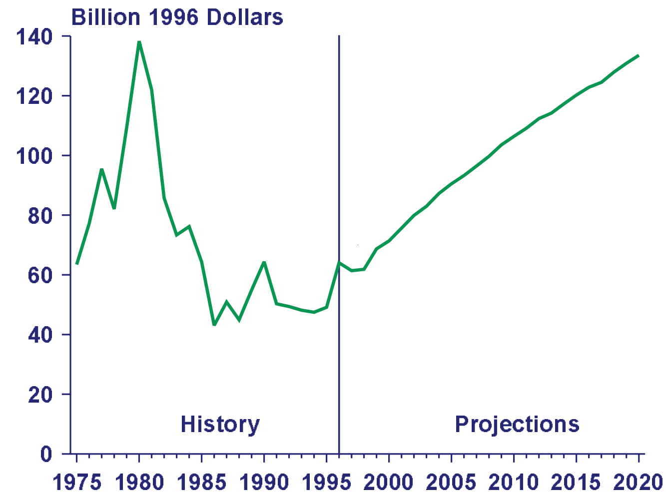
None of these simple vulnerability measures assesses the probability of disruption. An ideal measure might include a disruption probability, based on the level of concentration of control of the world export market and on other economic, political, and military factors.

Economic Measures

Economic measures of oil security are at least as important, if not more so, than physical measures. Physical shortages or disruptions are quickly manifested as price increases. Thus, any discussion of disruption quickly leads to discussion of prices. Since September 1991, the *Monthly Energy Review* has reported the value of *petroleum* imports and exports; long before that, in December 1978, it began reporting the value of total *energy* imports and exports.

The *AEO97* began to report gross expenditures on imported oil as a measure of the impact of oil imports. In *AEO98* the measure was refined to net expenditures on imported oil. This calculation was added to the *AEO* as a result of an article coauthored by then-Deputy Secretary of Energy Charles Curtis.[11] It cited the steady rise to an annual $100-billion-plus projected cost for imports as an argument for increased spending on energy research and development. As startling as the doubling of the value of oil imports may be, even by 2020 the total value is not expected to exceed the 1980 peak of $138 billion in constant 1996 dollars (Figure 5). Oil imports were very expensive in 1980 because the price of oil was nearly $62 a barrel. By 1986 the price of oil had dropped by two-thirds and the number of barrels of net oil imports had declined by 15 percent, causing the value of imported oil to decline to about $43 billion in 1996 dollars. As U.S. oil consumption increases and production declines, the cost of imported oil is expected to rise through 2020.

Figure 5. Net Expenditures for Imported Crude Oil and Petroleum Products, 1975-2020

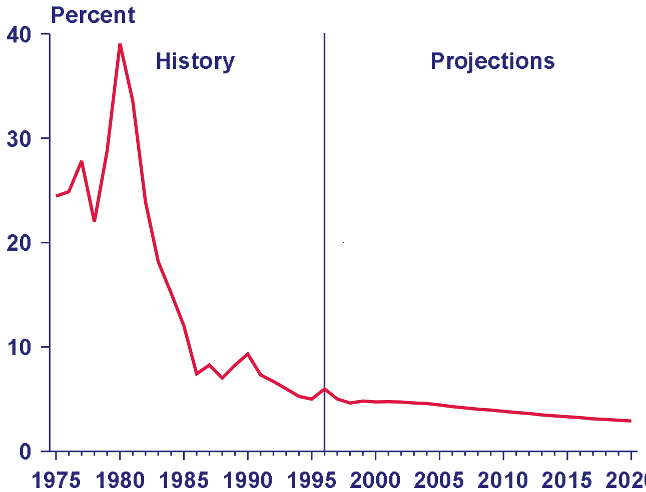


Sources: **History:** Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(98/02) (Washington, DC, February 1998). **Projections:** EIA, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

While it is interesting to know that Americans pay a rising bill for imported oil, in the context of total imports of goods and services, the bill for imported oil is rather small. From a peak of 39 percent in 1980, net oil spending as a percentage of total imports fell to a mere 6 percent in 1995 and is expected to fall below 3 percent in 2020 (Figure 6). The most significant decline in the oil percentage of imports occurred from 1980 to 1986, from 39 to 7 percent, as the world oil price dropped to less than one-third of its 1980 value, physical barrels of U.S. net oil imports declined by 15 percent, and total U.S. imports increased. During the same period OPEC lost its grip on the world oil price, as high world oil prices pushed

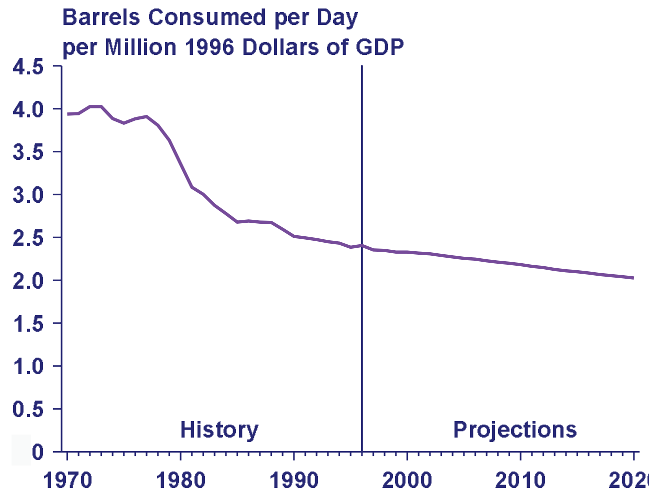
[10]Energy Information Administration, *International Energy Outlook 1994*, DOE / EIA-0484(94) (Washington, DC, July 1994), p. 21.
[11]J.J. Romm and C.B. Curtis, "Mideast Oil Forever?" *The Atlantic Monthly* (April 1996), pp. 57-74.

Figure 6. Oil Expenditures as a Percentage of Total Spending on Imported Goods and Services, 1975-2020



Sources: **History:** Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997); EIA, *Monthly Energy Review*, DOE/EIA-0035(98/02) (Washington, DC, February 1998); and DRI/McGraw Hill, Macroeconomic Forecasting Database. **Projections:** EIA, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), and DRI/McGraw Hill, Macroeconomic Forecasting Database.

Figure 7. U.S. Oil Intensity, 1970-2020



Sources: **History:** Energy Information Administration (EIA), *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997). **Projections:** EIA, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

down demand and pulled up non-OPEC oil production by 15 percent. Aided by a strong dollar, total U.S. imports of goods and services, particularly automobiles and capital goods, grew by 64 percent from 1980 to 1986, even as the value of oil imports was declining. In the future, oil imports and oil prices are expected to grow, but not as fast as total imports.

Measures such as the value of oil imports and the oil percentage of total expenditures on imported goods and services might be thought of as economic measures of oil dependence. As with physical measures, economic dependence measures are probably less valuable to long-run thinking about energy security than are economic vulnerability measures.

Oil intensity—oil consumption per dollar of gross domestic product (GDP)—is one measure of the economy's vulnerability to oil disruptions. As oil intensity declines, an oil disruption of a given size will have less effect on the economy. For example, if reduced oil intensity comes about through increased mileage per gallon, a disruption should also have less effect on drivers. However, oil intensity might also decline as vehicle miles traveled decline because of an economic slowdown.

The EIA begin to publish a measure of energy intensity in the *Monthly Energy Review* in March 1979 and continues to do so. A measure of oil intensity has never been published on a regular basis, however. (Petroleum intensity was included in a graph in the EIA report, *Energy Conservation Indicators 1986*.[12]) The GAO chose oil intensity as one of its measures of vulnerability to supply disruptions.

Since 1970 oil intensity has generally declined, even though oil consumption has increased, because GDP has increased even faster (Figure 7). The United States experienced a significant decline in oil intensity from 1976 to 1985, as high oil prices squeezed out the most expensive uses for oil and the easiest to switch to other fuels, such as home heating and electricity generation. Oil intensity is expected to continue declining in the future, falling by 16 percent from 1996 through 2020.

A similar measure that has occasionally been used in EIA publications is energy expenditures per dollar of GDP. Petroleum expenditures per dollar of GDP have also been used. These measures show that end-use energy and petroleum expenditures peaked in 1980-1981 at 14 and 9 percent of GDP, respectively. After that, the energy and petroleum shares declined steadily to about 7 and 3 percent today.

Conclusion

Measures of oil dependence and vulnerability can be divided into physical and economic dimensions. Physical measures describe the relative level of imports or the prospects for shortages and disruptions. Economic measures are less familiar. They describe the cost of imports or the prospects for price shocks.

Whether physical or economic, in the long run measures of vulnerability are likely to be more useful to policymakers than measures of dependence. Measures of

[12]Energy Information Administration, *Energy Conservation Indicators 1986*, DOE/EIA-0441(86) (Washington, DC, February 1988), p. 5.

dependence simply show the extent of the Nation's imports. By themselves they provide little information about energy security. In contrast, measures of vulnerability show the meaning of the imports, indicating the Nation's vulnerability to shortages, disruptions, and price spikes. By studying measures of vulnerability, policymakers can gauge their progress toward insulating the Nation from the harmful effects of sharp changes in the world oil market.

Motor Fuels Tax Trends and Assumptions

by
Stacy MacIntyre

After crude oil costs, taxes are the second largest component of the end-use price of gasoline and diesel fuel. The Annual Energy Outlook 1998 (AEO98) makes assumptions about future taxes on these fuels that affect their projected prices. The AEO98 forecast assumes that excise taxes at the State level will keep pace with inflation, and that Federal taxes will remain at current nominal levels, decreasing over time in inflation-adjusted 1996 dollars. The result of these assumptions is a reduced tax component in projected motor fuels prices. This paper evaluates the methodology for State and Federal motor fuels taxes with respect to historical trends and the assumptions of comparative forecasts.

Introduction

As of January 1, 1998, State and Federal taxes added an additional 38 and 43 cents per gallon to the respective pump prices of gasoline and diesel fuel. Motor fuels taxes in the United States are relatively small in comparison with those in European countries. Gasoline taxes in Europe range from $2.38 per gallon in Germany to $2.93 in the United Kingdom, and diesel fuel taxes range from $1.51 in Germany to $2.76 in the United Kingdom.[1] Although motor fuels taxes in the United States are relatively low, they represent a substantial portion of the prices paid by consumers. Taxes represented 32 percent of the price of gasoline in 1997 and 37 percent of the diesel fuel price. In the *Annual Energy Outlook 1998* (*AEO98*) projections, taxes shrink to 22 percent of the gasoline price in 2020 and 26 percent of the diesel fuel price (Table 1). Inflation-adjusted taxes are projected to decline by 9 cents per gallon for gasoline and by 12 cents per gallon for diesel fuel over the forecast period.

Inflation-adjusted motor fuels taxes decline in *AEO98* as a result of the assumptions made about Federal and State taxes. Federal taxes are assumed to remain at

Table 1. Composition of End-Use Prices for Gasoline and Diesel Fuel, 1997 and 2020

Component	Value (1996 Dollars per Gallon)		Share of End-Use Price (Percent)	
	1997	2020	1997	2020
Gasoline[a]				
Total End-Use Price	**1.20**	**1.27**	—	—
Crude Oil Costs	0.45	0.53	38	42
Taxes	0.38	0.29	32	22
Federal	0.18	0.09	15	7
State	0.20	0.20	17	16
Refining, Marketing, and Distribution	0.37	0.45	31	35
Diesel Fuel				
Total End-Use Price	**1.16**	**1.18**	—	—
Crude Oil Costs	0.45	0.53	39	45
Taxes	0.43	0.31	37	26
Federal	0.24	0.12	21	10
State	0.19	0.19	17	16
Refining, Marketing, and Distribution	0.27	0.34	24	29

[a]Average for all grades.

Note: Totals may not equal sum of components due to independent rounding.

Sources: 1997: Total end-use prices are the sum of end-use prices from Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(98/03) (Washington, DC, March 1998), Table 2, and annual volume-weighted taxes estimated by the Office of Integrated Forecasting and Analysis. Refining, marketing, and distribution costs estimated as total end-use prices less crude oil costs and taxes. 2020: EIA, AEO98 National Energy Modeling System, run AEO98B.D100197A (October 1997).

[1]Federal Highway Administration, *Monthly Motor Fuel Reported by States* (Washington, DC, January 1998).

current levels, resulting in a 50-percent decline in taxes after adjusting for inflation. State taxes, on the other hand, are assumed to increase at the rate of inflation, which means that they remain constant after adjusting for inflation. For modeling purposes, State-level taxes are aggregated by Census division (Figure 1). Because of the lack of regional historical series, however, State taxes are discussed in terms of an aggregate national average in this analysis.

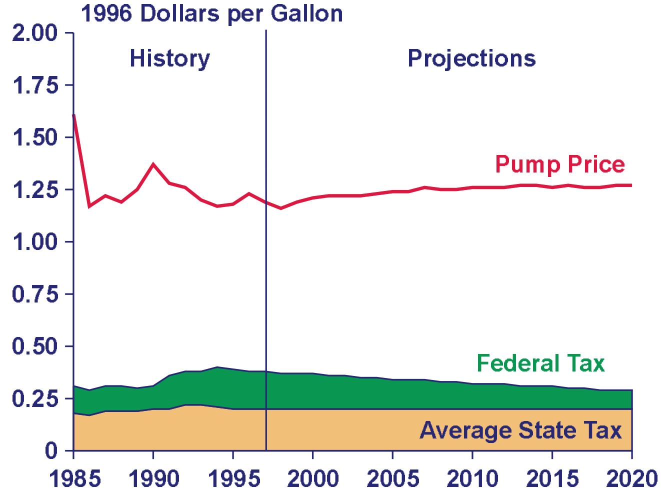
The historical and projected relationships between inflation-adjusted Federal and State taxes and gasoline prices are shown in Figure 2. The following analysis provides a historical summary of motor fuels taxes at the Federal and State levels and compares the historical trends with the *AEO98* assumptions. The *AEO98* assumptions are then compared with the assumptions used by DRI / McGraw-Hill (DRI) and the WEFA Group (WEFA) in their price projections.

Background

Motor fuels taxes have a long history as a revenue source for both Federal and State governments. The historical discussion of taxes in this section is given in terms of nominal dollars, because tax legislation is enacted in terms of nominal rather than inflation-adjusted dollars.

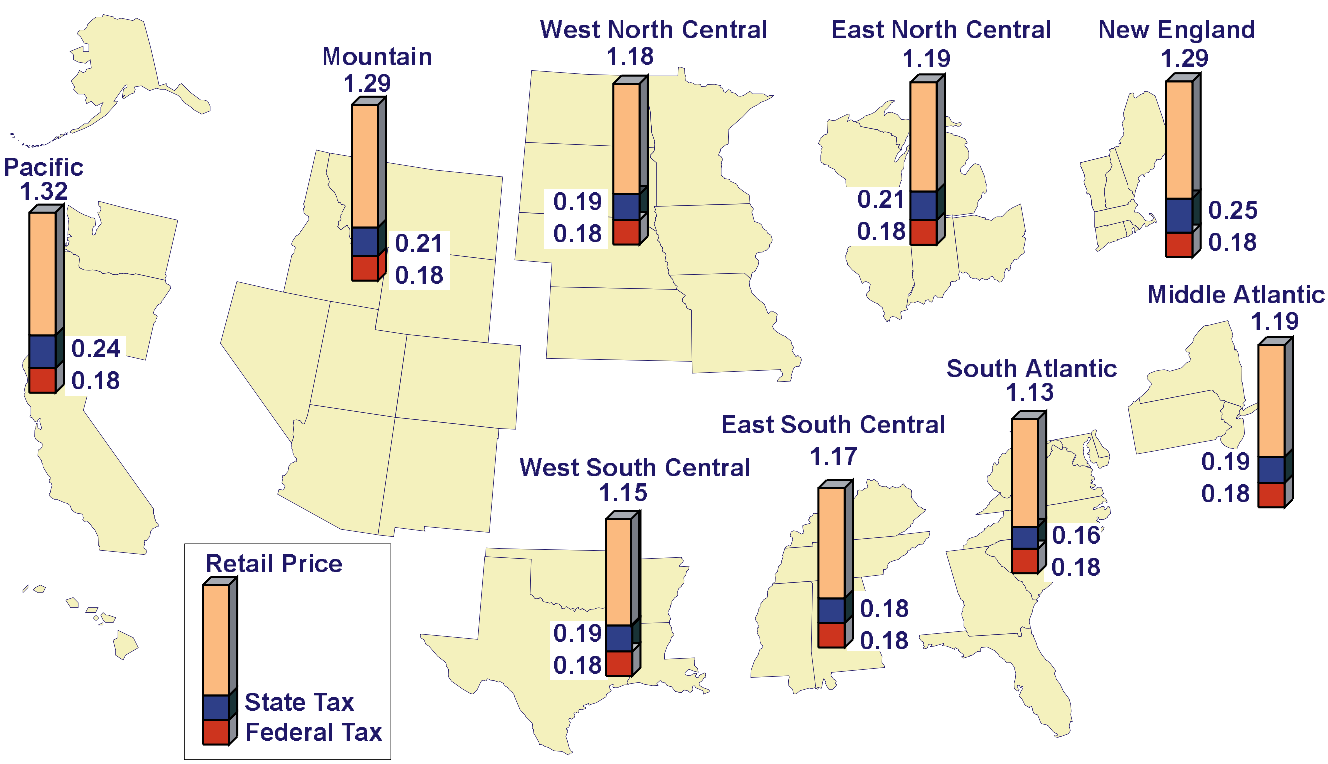
A 1-cent-per-gallon Federal excise tax on gasoline was initially created by Congress in 1932 for the purpose of deficit reduction.[2] Congress passed several minor increases to the tax rate during the 1930s, 1940s and, 1950s (Figure 3) to further deficit reduction and to fund U.S. military involvement in the Korean War. The diesel fuel tax was initiated by the Revenue Act of 1951, which set the tax rate for both gasoline and diesel at 2 cents per

Figure 2. Gasoline Prices and Taxes, 1985-2020



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

Figure 1. Motor Gasoline Taxes by Census Division, 1997
(1996 Dollars per Gallon)

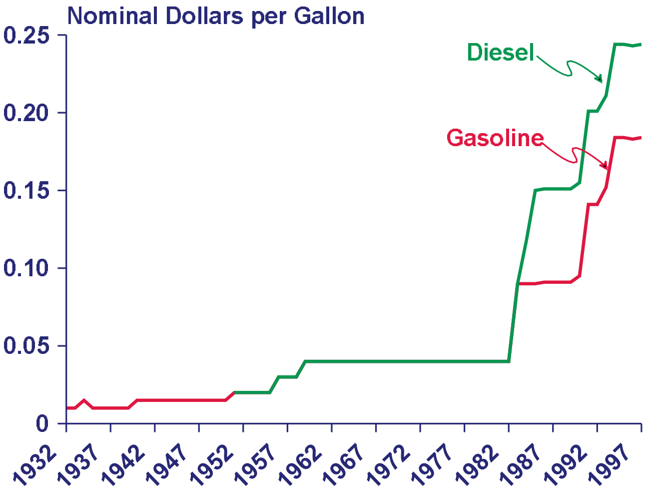


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

[2]Revenue Act of 1932 (P.L. 154).

gallon. Motor fuels taxes were not used to fund Federal highway construction, however, until 1956, when the Federal Highway Fund was created.[3] After another tax increase going toward highway funds was enacted in 1959, Federal taxes remained stable for a period of 23 years. This period of tax stability ended in late 1982 with the passage of the Surface Transportation Assistance Act, which marked a new era in motor fuels taxation.

Figure 3. Federal Motor Fuels Taxes, 1932-1997



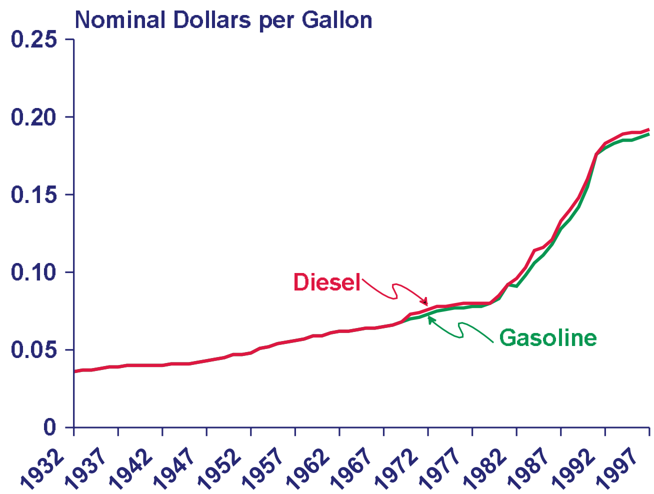
Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

After the recession of 1981-1982, motor fuels taxes became an even greater source of funds for Federal highways, which had fallen into disrepair. The Surface Transportation Assistance Act of 1982 (P.L. 97-424) increased the tax rate on gasoline and diesel fuel from 4 to 9 cents per gallon. The diesel tax rate was increased to 15 cents per gallon by the Tax Reform Act of 1984 (P.L. 98-369). The 6-cent-per-gallon increase in the diesel fuel tax was in lieu of increasing truck taxes based on vehicle weights. An additional 0.1 cent per gallon added to the gasoline and diesel tax rates in 1986 to fund the cleanup of underground storage tanks[4] expired in January 1996 but was reinstated on October 1, 1997.

The Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508) increased the tax rate on both gasoline and diesel fuel by another 5 cents per gallon. Half of the revenues went to the Highway Trust Fund and the other half toward general revenues. The most recent tax increase occurred at the end of 1993, when the Omnibus Budget Reconciliation Act of 1993 increased the excise tax on all motor fuels by 4.3 cents per gallon. The additional tax originally funded deficit reduction but was transferred to the Federal Highway Trust Fund starting on October 1, 1997.

State taxes on motor fuels have a more complex history than Federal taxes, because they include a mixture of rates, methods, and special-purpose fees. All 50 States have per-gallon excise taxes on gasoline and diesel fuel. In 1997 the rates ranged between 7.5 and 36 cents per gallon for gasoline and between 7.5 and 29 cents per gallon for diesel fuel (Table 2). In 11 States tax rates can be adjusted automatically on an annual, semiannual, or quarterly basis, using indexes or formulas specified in legislation. In addition to the per-gallon taxes collected by each State, 8 States—Arkansas (diesel only), California, Georgia, Hawaii, Illinois, Indiana, Michigan, and New York—also impose some type of sales tax or fee that is calculated as a percentage of the sales price. When State taxes are viewed on an aggregate level, the graph of the national average of total State taxes looks like a smooth trend. Although the rate of change varies over the historical period, the trend has always been an increasing one (Figure 4).

Figure 4. Average State Motor Fuels Taxes, 1932-1997



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

The first State gasoline tax, of 1 cent per gallon, was enacted in Oregon in 1919 for the purpose of financing highways. By 1929, every State had adopted a gasoline excise tax of between 2 and 6 cents per gallon, most of which went for highway finance. State gasoline taxes changed infrequently between 1919 and 1980, usually at 1-cent increments. The energy price shocks of the 1970s led to energy conservation, which dampened tax revenues. Slumping revenues and growing highway repair costs combined to put upward pressure on motor fuels taxes. As a result, in the 1980s States increased taxes more frequently and by larger amounts than they had in

[3]Congressional Research Service, *Disparate Impacts of Federal and State Highway Taxes on Alternative Motor Fuels*" (Washington, DC, March 1993).

[4]Superfund Amendments and Reauthorization Act of 1986 (P.L. 99-499).

Table 2. State Tax Rates on Gasoline and Diesel Fuel as of February 1, 1998
(Nominal Cents per Gallon)

State	Gasoline	Diesel Fuel	State	Gasoline	Diesel Fuel
Minimum	7.50	7.50	Mississippi	18.40	18.40
Maximum	36.00	30.80	Missouri	17.00	17.00
			Montana	27.00	27.75
Alabama	18.00	19.00	Nebraska	24.60	24.60
Alaska	8.00	8.00	Nevada	24.75	27.75
Arizona	18.00	27.00	New Hampshire	18.70	18.70
Arkansas[a]	18.60	18.60	New Jersey	10.50	13.50
California[a]	18.00	18.00	New Mexico	18.88	19.88
Colorado	22.00	20.50	New York[a]	22.80	22.65
Connecticut	36.00	18.00	North Carolina	22.30	22.30
Delaware	23.00	22.00	North Dakota	20.00	20.00
District of Columbia	20.00	20.00	Ohio	22.00	22.00
Florida	13.00	25.00	Oklahoma	17.00	14.00
Georgia[a]	7.50	7.50	Oregon	24.00	24.00
Hawaii[a]	16.00	16.00	Pennsylvania	25.90	30.80
Idaho	25.00	25.00	Rhode Island	29.00	29.00
Illinois[a]	19.00	21.50	South Carolina	16.00	16.00
Indiana[a]	15.00	16.00	South Dakota	21.00	21.00
Iowa	20.00	22.50	Tennessee	20.00	17.00
Kansas	18.00	20.00	Texas	20.00	20.00
Kentucky	16.40	13.40	Utah	24.50	24.50
Louisiana	20.00	20.00	Vermont	20.00	17.00
Maine	19.00	20.00	Virginia	17.50	16.00
Maryland	23.50	24.25	Washington	23.00	23.00
Massachusetts	21.00	21.00	West Virginia	25.35	25.35
Michigan[a]	19.00	15.00	Wisconsin	23.80	23.80
Minnesota	20.00	20.00	Wyoming	9.00	9.00

[a]State collects additional taxes calculated as a percentage of the sales price.
Note: State tax rates reflect local option taxes only when they have been applied uniformly State-wide.
Source: Federal Highway Administration, web site www.fhwa.dot.gov/ohim/mmfrnov.pdf, Table MF-121T for February 1998 (April 13, 1998).

the past.[5] On average, State fuel taxes nearly doubled between 1980 and 1990, growing at an average annual rate of 6.4 percent for gasoline and 6.5 percent for diesel. Growth in State taxes slowed in the 1990s, with average annual increases of 2.9 percent for gasoline and 2.6 percent for diesel between 1990 and 1997.

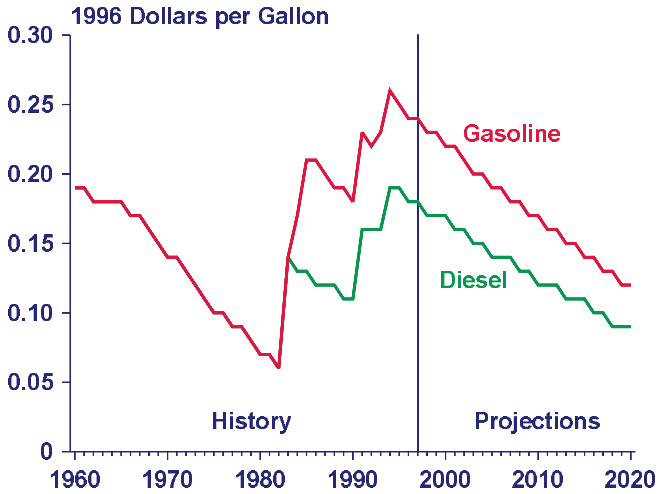
Federal Tax Methodology

In *AEO98* and previous *AEO* forecasts, Federal taxes on gasoline and diesel fuel were assumed to remain at current levels. The assumption is in keeping with the overall Federal policy-neutral stance of the forecast, and it enables NEMS to be used for analysis of proposed Federal tax changes with *AEO98* as a baseline. Scenarios related to carbon taxes and carbon stabilization are the most recent examples of such analysis. Motor fuels tax laws typically have an expiration date, but for the *AEO* analysis they are not assumed to expire. Because motor fuels taxes have not been allowed to expire in the past, the *AEO98* forecast and its predecessors have assumed that these taxes will be reissued. The following paragraphs look at the assumption of no new taxes in light of previous tax trends.

Projections in *AEO98* are presented in terms of inflation-adjusted 1996 dollars. Adjusting the historical tax series for inflation shows periods of decline when inflation was rising faster than taxes, and periods of increase when taxes were rising faster than inflation (Figure 5). Despite numerous tax increases in the 1980s and early 1990s, the inflation-adjusted tax level for gasoline did not approach the 1960-1961 level of 19 cents per gallon (1996 dollars) until after the 1993 tax hike. Inflation has since eroded the gasoline tax value to 18 cents per gallon

[5]Congressional Research Service, *Disparate Impacts of Federal and State Highway Taxes on Alternative Motor Fuels* (Washington, DC, March 1993).

Figure 5. Federal Motor Fuels Taxes, 1960-2020



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

in 1996 dollars. Because the diesel tax increased by 6 cents per gallon more than the gasoline tax in 1984, the inflation-adjusted diesel tax is still above its 1960-1961 level.

The assumption of no new Federal taxes means that taxes are projected to decline between 1997 and 2020 in terms of inflation-adjusted 1996 dollars (Figure 5). Inflation cuts the value of Federal gasoline and diesel fuel taxes in half between 1997 and 2020, reducing the gasoline tax by 9 cents and the diesel fuel tax by 12 cents per gallon over the forecast period. The assumed tax levels look reasonable from a historical perspective, as they fall within the range of historical tax values. The tax value at the end of the forecast is similar to those of the mid-1970s and higher than those of the late 1970s and early 1980s. A 13-cent-per-gallon decline in the value of Federal gasoline and diesel fuel taxes actually occurred between 1959 and 1982, a period during which the tax rates did not change.

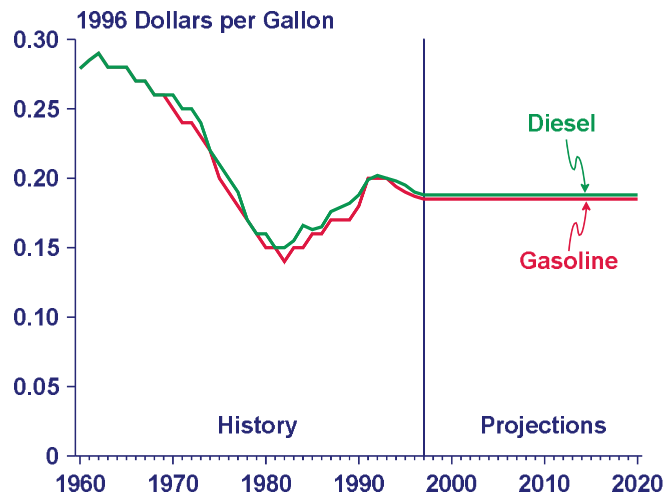
When Federal taxes are looked at in terms of their share of total prices, the tax shares projected in *AEO98* also fall within the historical range. Since 1970 the Federal tax component of gasoline prices has ranged between 3 and 17 percent. The 1997 Federal tax share of 15 percent is among the highest since 1970. By 2020 the Federal tax component of the projected gasoline price falls to only 7 percent, among the lowest values of the historical range. The tax component of diesel fuel prices can only be looked at since 1983, when EIA began collecting the diesel fuel price series. Since that time Federal taxes have represented between 8 and 22 percent of diesel prices, with the 1997 share of 21 percent representing the third highest of the period. In comparison, the 2020 Federal tax share of the projected diesel fuel price is 10 percent, the third lowest of the period.

The political nature of taxes makes them highly unpredictable. In the past, the one predictable aspect of motor fuels tax policy was that all significant changes were tax increases. However, recent expectations of budget surpluses have created some uncertainty in the opposite direction by opening up the possibility that motor fuels taxes might be reduced.

State Tax Methodology

In *AEO98* and previous forecasts, State taxes on gasoline and diesel fuel are assumed to grow at the rate of inflation. When adjusted for inflation, the assumed State taxes look like a flat trajectory (Figure 6). The assumption was chosen because it results in a trajectory that falls within historical bounds, whereas alternative assumptions would have resulted in trajectories that go outside the bounds.

Figure 6. Average State Motor Fuels Taxes, 1960-2020



Source: AEO98 National Energy Modeling System, run BASECOMP.D101797A (October 1997).

From a historical perspective, the assumed values fall between the peak of the early 1960s and the trough of 1982. The graph of average State taxes adjusted for inflation shows that during the 1960s and 1970s they did not keep pace with inflation, resulting in a declining tax value. In fact, the tax value was cut in half between 1962 and 1982, dropping from 29 cents per gallon to 14 cents per gallon for gasoline and from 29 cents per gallon to 15 cents per gallon for diesel fuel. In contrast, average State tax values rose between 1983 and 1993 as taxes increased faster than inflation. After adjusting for inflation, State taxes for both fuels grew by more than 5 cents per gallon between 1983 and 1993. After 1993, growth in State taxes slowed relative to inflation, resulting in a 1-cent decline for both fuels.

Since 1970 the average State tax for gasoline, adjusted for inflation, has represented between 7 and 21 percent of the end-use price. State taxes represented the highest percentages in the early 1970s, when oil prices were relatively low, and the lowest percentages in between 1979 and 1985, when oil prices were relatively high. Between 1974 and 1978 and in the years since 1986 State taxes have represented between 12 and 17 percent of gasoline prices. The *AEO98* gasoline price projection for 2020 reflects a State tax component of 15 percent. Looking at the same shares for the average State diesel tax, the shares have ranged between 10 percent and 17 percent since 1983 (a diesel price series is not available before 1983). In general, State taxes as a share of diesel prices have increased over time, with the share ranging between 16 and 17 percent since 1991. The State tax share reflected in the 2020 diesel price projection is 16 percent, which is comparable to the levels of the 1990s.

According to analysis by the Federal Highway Administration, State tax rates have historically been influenced by growth in fuel consumption in two different ways.[6] Growth in consumption results in increased revenues which tend to reduce pressure for States to increase tax rates. On the other hand, growth in vehicle miles traveled (VMT) leads to greater requirements for highway investments and the revenues to support them. Looking at the *AEO98* growth rates for projected consumption and VMT provides little insight about State tax behavior, because the rates are similar. Consumption levels for gasoline and diesel are projected to grow at average annual rates of 1.1 percent and 1.4 percent, respectively, while VMT grows by 1.5 percent annually. If anything, the slightly higher growth rate for VMT would point to a greater need for revenues for highway spending.

The rate of increase in State motor fuels taxes may also be affected by the level of Federal funding relative to highway spending requirements. In general, increases in Federal highway funding require matching funds from States, creating greater revenue requirements for the States. Revenues increase in the absence of tax rate changes as the consumption of gasoline and diesel grows, but pressure to increase State motor fuels taxes occurs when the growth in revenues falls short of increases in highway spending.[7] The possible link between growth in State fuels tax rates, the Federal share of highway spending, and motor fuel consumption can be evaluated by looking at implied tax revenues in the *AEO98* forecast. It is important to note that tax revenues do not necessarily equate to highway spending (some tax revenues may be spent for other projects, such as mass transit); however, tax revenues do indicate an availability of funds. The combined Federal and State revenue generated from gasoline and diesel fuel consumption in the *AEO98* projections declines from $59.2 billion in 1997 to $57.4 billion in 2020 in inflation-adjusted dollars.

Because no increases in Federal fuels taxes are assumed in the forecast, a long-term decline in the Federal share of total tax revenues occurs. The Federal share of tax revenues generated from motor fuels in 2020 shrinks to 33 percent, compared with 49 percent in 1997. Such a decline would presumably create pressure to increase State tax revenues. The rising consumption contributes to an increase of $8.6 billion (1996 dollars) in State motor fuels tax revenues. The question is whether this projected growth in State tax revenues will be enough to keep up with the growing revenue requirements for highway funding over the forecast period.

Methodologies of Other Forecasters

Other energy modelers, such as DRI and WEFA, make different assumptions about fuel taxes. Both the DRI and WEFA forecasts reflect gasoline and diesel fuel prices for the year 2020 that are substantially higher than the *AEO98* projections. Review of the tax assumptions for the alternative forecasts reveals that the composition of the projected prices—i.e., crude oil costs, taxes, and refining, marketing, and distribution costs—also differ from those in the *AEO98* projections (Table 3).

Other forecasts that do not adhere to the policy-neutral assumption for Federal taxes reflect nominal increases in Federal taxes over the forecast period. Comparing Federal gasoline taxes, the increases assumed by DRI and WEFA fall short of the rate of inflation, resulting in inflation-adjusted tax levels of 15 cents per gallon in both forecasts. This tax level is 3 cents below the 1997 value but 6 cents above the *AEO98* assumption. In the DRI forecast, diesel fuel taxes also fall short of inflation but exceed the *AEO98* tax level by 4 cents per gallon. In the WEFA forecast, diesel fuel taxes keep pace with inflation and are 12 cents per gallon above the *AEO98* tax level.

State taxes on diesel fuel grow with inflation in all three forecasts, but State taxes on gasoline grow at different rates. After adjusting for inflation, the State gasoline taxes in the DRI forecast are about 1 cent per gallon below the *AEO98* tax level. The WEFA forecast reflects somewhat higher State gasoline taxes, which are about 6 cents per gallon above the *AEO98* level.

Although the DRI price projections are substantially higher than those of *AEO98* and WEFA, they are similar to the *AEO98* price projections in terms of their price components. As a percentage of end-use prices, the DRI breakdown of crude costs, total Federal and State taxes, and the refining, marketing, and distribution costs is almost identical to that of *AEO98*. However, the split between Federal and State taxes differs between DRI

[6]Federal Highway Administration, "State Motor-Fuel Tax Trends in the 1990's: Why Has the Pace of Rate Increases Declined?" Discussion Paper (Washington, DC, May 1998).

[7]Federal Highway Administration, "State Motor-Fuel Tax Trends in the 1990's: Why Has the Pace of Rate Increases Declined?" Discussion Paper (Washington, DC, May 1998).

Table 3. Composition of End-Use Prices for Gasoline and Diesel Fuel, 1997 and 2020

Component	Value (1996 Dollars per Gallon)				Share of End-Use Price (Percent)			
		2020				2020		
	1997	*AEO98*	DRI	WEFA	1997	*AEO98*	DRI	WEFA
Gasoline								
Total End-Use Price	1.20	1.27	1.46	1.28	—	—	—	—
Crude Oil Costs	0.45	0.53	0.60	0.50	38	42	41	39
Taxes	0.38	0.29	0.34	0.40	32	22	23	32
Federal	0.18	0.09	0.15	0.15	15	7	10	11
State	0.20	0.20	0.19	0.26	17	16	13	20
Refining, Marketing, and Distribution	0.37	0.45	0.52	0.38	31	35	36	30
Diesel Fuel								
Total End-Use Price	1.16	1.18	1.32	1.24	—	—	—	—
Crude Oil Costs	0.45	0.53	0.60	0.50	39	45	45	39
Taxes	0.43	0.31	0.36	0.43	37	26	27	34
Federal	0.24	0.12	0.18	0.24	21	10	14	19
State	0.19	0.19	0.19	0.19	17	16	14	15
Refining, Marketing, and Distribution	0.27	0.34	0.37	0.31	24	29	28	24

Note: Totals may not equal sum of components due to independent rounding.

Sources: 1997: End-use prices are the sum of end-use prices from Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(98/03) (Washington, DC, March 1998), Table 2, and annual volume-weighted taxes estimated by the Office of Integrated Forecasting and Analysis. Refining, marketing, and distribution costs estimated as the difference between end-use prices and the sum of crude oil costs and taxes. 2020: EIA, AEO98 National Energy Modeling System, run AEO98B.D100197A (October 1997).

and *AEO98*, with Federal taxes representing higher shares of gasoline and diesel end-use prices and State taxes representing lower shares than in *AEO98*.

The WEFA forecast shows a much higher tax share of projected prices. In the WEFA gasoline projection, Federal taxes represent a slightly higher share of the total price, and State taxes represent a dramatically higher share than in the DRI and *AEO98* projections. State taxes represent 20 percent of the end-use gasoline price projected by WEFA, compared with 16 percent for *AEO98* and 13 percent for DRI. In contrast, it is the Federal tax component that is relatively high in the WEFA forecast for diesel fuel, representing 19 percent of the diesel fuel price, compared with 14 percent of the DRI price and 10 percent of the *AEO98* price. The Federal, State, and total tax shares in all three forecasts fall within historical ranges. The percentage of State taxes reflected in the WEFA gasoline price projection is noteworthy because it is similar to the peak levels of the early 1970s.

Summary

Motor fuels taxes represent a significant component of retail gasoline and diesel prices, and assumptions about what taxes will look like in the future have a major impact on their price projections. The State and Federal tax assumptions used in *AEO98* are not only important to the gasoline and diesel price projections but also explain some of the differences between the *AEO98* projections and those of other forecasters.

The *AEO98* Federal tax methodology assumes current laws and legislation, which means that Federal taxes on gasoline and diesel fuel remain at current levels. Although significant changes to motor fuels taxes have always been tax increases in the past, recent projections for Federal budget surpluses make tax reductions a possibility. After adjusting for inflation, *AEO98* Federal taxes on both gasoline and diesel fuel are cut in half by 2020. In addition, the shares of projected prices represented by Federal taxes are also cut in half. The decline in inflation-adjusted Federal taxes in *AEO98* is not as dramatic as it first appears when it is put into a historical context. The projected Federal taxes in real terms are within historical bounds, and the reduction is similar to the decline in tax values between 1959 and 1982.

The *AEO98* assumption that State taxes will increase at the rate of inflation also looks reasonable in the context of historical trends. Throughout the *AEO98* forecast, aggregate State taxes remain constant at 20 cents per gallon for gasoline and 19 cents per gallon for diesel fuel, in terms of inflation-adjusted 1996 dollars. Between 1960 and 1997, average State taxes ranged between 29 cents per gallon for gasoline and diesel in 1962 and 14 cents per gallon and 15 cents per gallon for gasoline and diesel, respectively, in 1982. As price components, State taxes represent 15 percent of the projected gasoline price and 16 percent of the projected diesel fuel price in the *AEO98* forecast. These percentages are within historical ranges and are consistent with shares during the 1990s.

A comparison of *AEO98* tax assumptions with those of DRI and WEFA uncovers some interesting differences between forecasts. Unlike *AEO98*, DRI and WEFA do not assume "current laws and legislation" but instead assume increases from current Federal tax levels. Although relatively higher than *AEO98*, the Federal taxes on gasoline in both the DRI and WEFA forecasts reflect a decline in terms of 1996 dollars. The Federal diesel tax in the DRI forecast also represents a decline in inflation-adjusted dollars, but the Federal diesel tax in the WEFA forecast remains the same after adjusting for inflation. Looking at State taxes, all three forecasts reflect taxes on diesel fuel that keep pace with inflation. In terms of State taxes on gasoline, DRI is only 1 cent below the *AEO98* inflation-adjusted levels. WEFA reflects higher State gasoline taxes relative to the other two and is 6 cents above the 1997 level and the *AEO98* projection and 7 cents above the DRI projection in 1996 dollars.

In terms of its share of total product prices, the Federal tax component in all three forecasts is lower than current levels but still within the historical range. The State tax component in all three forecasts is similar to historical levels; however, the WEFA tax component is somewhat higher, equivalent to the peak levels of the early 1970s.

In conclusion, although the *AEO98* tax methodology results in a decrease of 9 cents per gallon (1996 dollars) in the value of Federal taxes and shifts the composition of projected gasoline and diesel fuel prices, the methodology is reasonable in terms of historical trends and in comparison with other forecasts.

Coal Pricing Methodology for the *Annual Energy Outlook 1998*

by
Michael Mellish

Coal supply curves, representing the relationships between the minemouth prices of coal and the corresponding quantities of annual production, are a necessary component of the Energy Information Administration's (EIA) mid-term energy forecasting system. This paper discusses the revised coal pricing methodology used for the projections presented in the Annual Energy Outlook 1998 *(*AEO98*). In previous EIA forecasts, coal prices were estimated through an approach that made use of both econometric and engineering methodologies. Econometric equations related minemouth coal prices to changes in capacity utilization, labor productivity, wages, and fuel costs. Additionally, engineering cost equations and data and assumptions regarding U.S. coal reserves were used to adjust minemouth coal prices for the impacts of reserve depletion on future mining costs and to determine the least-cost supplies of new mining capacity. The new econometric methodology relates minemouth prices for specific coal-producing regions and mine types to a set of independent variables that include coal production, labor productivity, wages, fuel costs, and the costs of capital equipment. The methodology avoids problems related to the limited availability of capacity utilization data, has a simpler functional form, and more accurately captures the regional relationships between prices and labor productivity. The discontinued use of engineering cost equations for estimating the impacts of reserve depletion on mining costs reflects EIA's concerns about the substantial level of resources required for updating the equations and the inherent uncertainties in the projected cost estimates.*

Background

The Coal Market Module (CMM) of the National Energy Modeling System (NEMS) provides annual projections of U.S. coal production, distribution, and prices. In addition, the international component of the CMM provides projections of annual world coal trade flows from major supply to major demand regions, generating regional forecasts of U.S. coal exports. The core component of the CMM is the Coal Distribution Submodule (CDS), which determines the least-cost supplies of coal (minemouth price and transportation cost) to meet a given set of U.S. coal demands by sector and region. Minemouth coal prices are obtained from a set of regional supply curves generated by the CMM's Coal Production Submodule (CPS). Domestic production and distribution of coal are projected for 11 supply regions and 13 demand regions.

This article focuses on the data and methodology used for estimating the econometric equation upon which the regional CPS supply curves are based. In general, the CPS produces annual econometric-based coal supply curves, representing the relationships between the minemouth prices of coal and the corresponding quantities of annual production. A separate supply curve is provided for all significant production by mine type (underground and surface), coal rank (bituminous, subbituminous, and lignite), coal grade (steam or metallurgical), and sulfur category in each of the 11 supply regions. Twelve coal types are represented in the CPS, reflecting unique combinations of coal rank, coal grade, sulfur content, and mine type. For the *Annual Energy Outlook 1998* (*AEO98*), U.S. coal supply was represented with a total of 34 supply curves (Table 1). By region, Northern Appalachia was represented with eight supply curves, the most of any of the regions. The Western Interior, Dakota Lignite, and Northwest regions were represented with a single supply curve for each region.

The methodology for estimating coal supply curves for *AEO98* reflects revisions from the one used for previous editions of the *Annual Energy Outlook*. The econometric methodology developed for *AEO98* relates minemouth prices in each coal-producing region represented in the CPS to a set of independent variables that include coal production, labor productivity, wages, fuel costs, and the costs of capital equipment.

Previously, coal prices were estimated through an approach that incorporated both econometric and engineering methodologies. Econometric equations related minemouth coal prices to changes in capacity utilization, labor productivity, wages, and fuel costs. Additionally, mine engineering cost equations and data and assumptions about the quantities, distribution, accessibility, and recoverability of coal reserves were used to adjust minemouth coal prices for the impacts of reserve depletion on mining costs and to determine the least-cost supplies of new mining capacity.

Table 1. Number of Coal Supply Curves by CMM Region and Mine Type

CMM Supply Region			States	Deep	Surface	Total
1	NA	Northern Appalachia	PA, OH, MD, WV (north)	4	4	8
2	CA	Central Appalachia	WV (south), KY (east), VA	3	2	5
3	SA	Southern Appalachia	AL, TN	3	2	5
4	EI	Eastern Interior	IL, IN, KY (west)	2	2	4
5	WI	Western Interior.	IA, MO, KS, AR, OK, TX (bituminous)	0	1	1
6	GL	Gulf Lignite	TX, LA	0	2	2
7	DL	Dakota Lignite.	ND, MT (east)	0	1	1
8	PG	Powder and Green River Basins	WY, MT (west)	1	2	3
9	RM	Rocky Mountain.	CO, UT	1	1	2
10	ZN	Southwest.	AZ, NM	0	2	2
11	AW	Northwest	AK, WA	0	1	1
U.S. Total				**14**	**20**	**34**

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The revised econometric methodology differs from that used for the *Annual Energy Outlook 1997* in that it incorporates production rather than capacity utilization as an independent variable, and it provides for regional variation in the coefficient for the labor productivity term. Also, the regression model for *AEO98* was estimated using additional years of data. The effects of reserve depletion on mining costs are implicitly captured through the labor productivity variable, replacing the previous use of engineering cost equations for explicitly estimating these costs.

The new econometric approach represents an improvement over the previous methodology in several ways: (1) the substitution of production for capacity utilization as a variable allows the use of additional years of data (see below); (2) the regional variation in the coefficient for the labor productivity term provides a more accurate representation of the relationships between minemouth prices and productivity; and (3) the model has a simpler functional form, providing more stable forecasts of coal prices over time than the previous equation.[1]

Use of Production in Place of Capacity Utilization as an Explanatory Regression Variable

The replacement of the capacity utilization term with production in the *AEO98* coal pricing model reflects, in part, issues regarding the limited years of available data for capacity utilization. Capacity utilization data for U.S. coal mines, as collected on the Form EIA-7A, "Coal Production Report," are available for 1979 through 1986 and for 1991 through 1996. These two sets of data, however, provide two distinctly different measures of capacity utilization. Capacity utilization data for 1979 through 1986 are based on estimates of daily productive capacity, whereas more recent capacity utilization data are based on estimates of annual productive capacity. For 1987 through 1990, estimates of daily productive capacity were collected, but, because the data were not to be published, they did not go through a complete data verification process.

For 1979 through 1986, EIA's "Coal Production Report" survey questionnaire requested that mine operators "Report the maximum amount of coal that realistically could be/was produced on any day during the year." EIA then calculated the annual productive capacity for each mine by multiplying reported daily productive capacity by the reported number of production days worked during the year.[2] The capacity utilization data reported in EIA publications are the ratios of reported annual production divided by the resultant estimates of annual productive capacity.

For 1991 through 1996, U.S. coal mines were requested to "Report the maximum amount of coal that your mining operation could have produced during the year with the existing mining equipment in place, assuming that the labor and materials sufficient to utilize the equipment were available, and that the market existed for the maximum production." Annual capacity utilization was calculated directly as the ratio of reported coal production for the year divided by reported annual productive capacity.

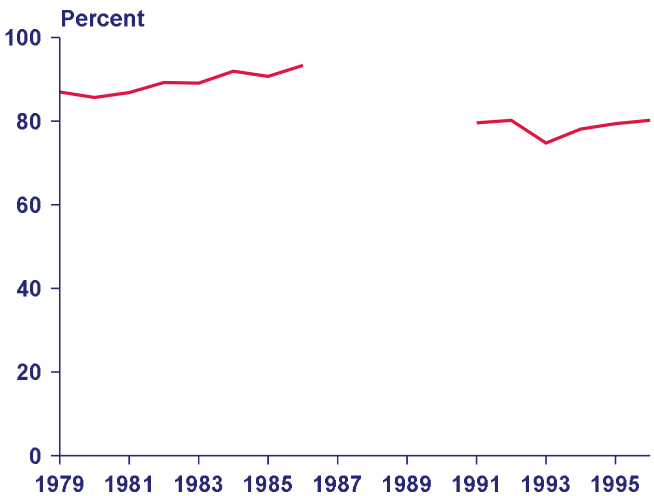
As shown in Figure 1, capacity utilization at the national level differs considerably for the two time periods. In general, estimates of capacity utilization are substantially higher for 1979 through 1986. In part, the higher utilization rates for the earlier period can be attributed to the limitation that the reported number of days worked during the year represented the number of days used to

[1]Some of the terms in the previous coal pricing equations (underground and surface) were specified with relatively large exponents. These functional forms indicated somewhat spurious variations in coal prices for some regions and mine types for relatively moderate changes in capacity utilization and factor input costs.

[2]Originally, only data on average daily capacity were reported for 1979 through 1986 in EIA's *Coal Production* reports. More recently, annual capacity utilization data for 1984, 1985, and 1986 have been published in issues of EIA's *Coal Industry Annual*.

calculate annual productive capacity. The capacity data collected for the years 1991 through 1996 do not incorporate this restriction. As a result, the previous coal pricing model incorporating capacity utilization as an independent variable was restricted to the 8 years (1979 through 1986) for which a consistent set of capacity utilization data was available. This limitation restricted the updating of the model with more recent data and raised issues about basing a forecast through 2020 on only a few years of data. In addition, short-run disequilibria in markets, which can lead to substantial changes in an industry's capacity utilization, do not typically extend beyond a few years. Therefore, the inclusion of a capacity utilization term in a relatively long-term forecast, such as the *AEO*, is difficult to justify.

Figure 1. Capacity Utilization at U.S. Coal Mines, 1979-1996



Source: Energy Information Administration, Form EIA-7A, "Coal Production Report."

These concerns led to the consideration of coal production data that are: (1) available for an extended time period and (2) consistent across all years. Also, there is solid economic rationale for the inclusion of production as an explanatory variable in a coal pricing model. In the economics literature, it is well established that supply curves for most products are upward sloping; thus, one should expect to observe a direct relationship between the quantity of a product supplied and its price, all other factors being held constant.

Estimating Cost Impacts of Reserve Depletion

The decision to discontinue the use of engineering cost equations for estimating the impacts of reserve depletion on future mining costs reflected EIA's concerns about the substantial level of resources required for updating the equations, as well as the uncertainties inherent in the estimates. In essence, the engineering cost equations that had been developed by EIA represented an effort to estimate the incremental costs associated with the differences in geologic conditions of new mines versus existing mines, holding constant factor input costs, labor productivity, and technology. However, observed productivity data reported by mining operations over time reflect a combination of factors that include, but are not limited to: (1) technological change; (2) economies of scale; (3) more (or less) efficient use of personnel and equipment; (4) the overall skill level of the workforce; and (5) reserve depletion.

In the approach adopted for *AEO98*, the effects of reserve depletion on future mining costs are implicitly captured through the labor productivity assumptions. This approach recognizes that observed levels of labor productivity over time are a function of a variety of factors, which include changing geologic conditions. Projected levels of labor productivity by region and mine type are an exogenous input to the CPS. For *AEO98*, projected productivity growth rates by region and mine type vary in accordance with historical trends. In the previous methodology, projected increases in labor productivity primarily reflected technological improvements. Impacts on future levels of labor productivity and mining costs from reserve depletion were captured through the engineering cost equations.

Data and Trends: Coal Industry Prices, Production, Labor Productivity, and Factor Input Costs

The econometric model of the U.S. coal industry developed for *AEO98* relates historical trends in the average price of coal at mines to a set of supply-side factors that include production, labor productivity, wages, fuel costs, and the costs of capital equipment. All prices, price indices, and wages in nominal dollar terms were converted to constant 1992 dollars using the implicit gross domestic product (GDP) deflator. The model includes annual data for 10 CPS supply regions and 2 mine types (surface and underground) for the years 1978 through 1994.[3] In all, the data set includes 255 observations, reflecting 17 years of data and 15 observations per year (10 surface and 5 underground).

The time period represented has seen substantial changes in factors affecting both the supply and demand for coal. While both supply- and demand-side factors are addressed in the coal pricing equation developed for *AEO98*, the discussion in this section focuses on the factors directly affecting the supply and costs of coal. The following sections provide information about the source and measure of each supply-side variable used in the coal pricing model, along with a brief review of the time trend for each variable.

[3]Data for coal mines in the Northwest supply region (Alaska and Washington) were not included in the regression model. The average mine price of coal for those States is withheld from EIA publications to avoid disclosure of individual company data.

Data

Data on the average price of coal at mines, production, and labor productivity are obtained from various issues of EIA's *Coal Production* and *Coal Industry Annual* reports. To avoid disclosure of individual company data, coal price data for several States are not published, and those data are also excluded from the model.[4] The States for which data were excluded were Maryland, Tennessee, Iowa, Missouri, Kansas, Arkansas, Louisiana, South Dakota, Arizona, Washington, and Alaska. Together, these States accounted for 2.7 percent of total production in 1996. In several other States (Indiana, Oklahoma, Montana, Wyoming, and New Mexico), data for underground mines were combined with data for surface mines. The combined data for these States were represented as surface-minable coal in the regression model.

The average price of coal at U.S. mines, in nominal dollars per ton,[5] is calculated by dividing the total value of the coal produced at a mine by its total reported production. U.S. coal mines report their total production and the total free on board (f.o.b.) mine value[6] of the coal produced. Reported coal production represents primarily the marketable product after preparation, which is either equal to or less than run-of-mine output. Calculated prices exclude data from mines producing less than 10,000 tons of coal during the year, which are not required to report information on the total mine value of coal produced. Data on U.S. coal production used in the coal pricing model, however, include production from mines producing less than 10,000 tons of coal during the year, as production quantities are not considered proprietary data.

Labor productivity (measured in tons of coal produced per miner hour) is calculated by dividing total reported production by the total direct labor hours by all employees engaged in production, preparation, processing, development, maintenance, repair, and shop or yard work at mining operations. Calculated productivity excludes data from mines producing less than 10,000 tons and preparation plants with less than 5,000 employee hours, which are not required to provide data on labor hours.

Data on the average annual wage for the U.S. coal industry are obtained from the U.S. Department of Labor, Bureau of Labor Statistics (BLS). The data are compiled and published by the BLS as part of its "Covered Employment and Wages," or ES-202, program. The primary source of the statistics is the quarterly tax reports submitted to State employment security agencies by employers subject to State unemployment insurance laws. Unlike EIA's "Coal Production Report," which focuses on workers directly involved in the production and preparation of coal, ES-202 data also include coverage of corporate officials, executives, clerical workers, and other office workers. Annual average wages are calculated as the reported total annual wage bill submitted by a reporting economic unit divided by the reported number of employees. Coal industry data are available by State for 1975 through 1996, and by State and mine type (for a majority of States) for 1988 through 1996. State-level data were used for the *AEO98* coal pricing equation, because of the need for a continuous data series for the entire period covered by the regression.

Fuel costs in the coal pricing equation are represented with a national-level price series for No. 2 diesel fuel. The specific series selected for the regression is the average annual refiner price of No. 2 diesel fuel to all users, as published in EIA's *Petroleum Marketing Annual*. According to data published by the U.S. Department of Commerce, diesel fuel represented more than 40 percent of the fuel costs at U.S. surface mines in 1992 and an estimated 11 percent of the fuel costs at underground mines.[7]

The producer price index (PPI) for mining machinery and equipment is obtained from the BLS. The PPI targets the output of U.S. companies, excluding products produced by foreign manufacturers. Producers are selected for the survey through a systematic sampling from a listing of all firms that file with the Unemployment Insurance System.[8] The PPI for mining machinery and equipment includes the manufacture of complete machines and component parts by establishments primarily engaged in the manufacture of heavy machinery and equipment for the mining industry. This price index, in conjunction with the yield on utility bonds, was used in constructing the regression variable representing the annualized user cost of mining equipment.

The variable *PCAP*, representing the annualized user cost of mining equipment,[9] is calculated as follows:

[4]A statistical methodology for estimating missing data (based on the EM algorithm) has been used successfully by EIA for estimating suppressed cells in data published from the EIA-846, "Manufacturing Energy Consumption Survey." In the future, the same procedure may be used to estimate coal prices for cells suppressed in tables in EIA's *Coal Production* and *Coal Industry Annual* reports, so that estimates of confidential coal data can be incorporated into the database for the coal pricing regression model. For a description of the EM algorithm, see R.J.A. Little and D.B. Rubin, *Statistical Analysis With Missing Data* (New York, NY: John Wiley and Sons, 1987), Section 7.2.

[5]Throughout this chapter, tons refers to short tons (2,000 pounds).

[6]The free on board mine price is the price paid for coal at the mining operation site. It excludes freight or shipping and insurance costs.

[7]U.S. Census Bureau, *1992 Census of Mineral Industries*, web site www.census.gov (accessed April 9, 1998).

[8]The sample size for the PPI for mining machinery and equipment (Series ID: PCU3532) for the February 1998 reporting cycle was 63 establishments. Personal communication (e-mail) from Chris Anfang, U.S. Department of Labor, Bureau of Labor Statistics, Washington, DC (April 2, 1998).

[9]D.W. Carlton and J.M. Perloff, *Modern Industrial Organization* (London, UK: Scott, Foresman and Company, 1990), Appendix 3A.

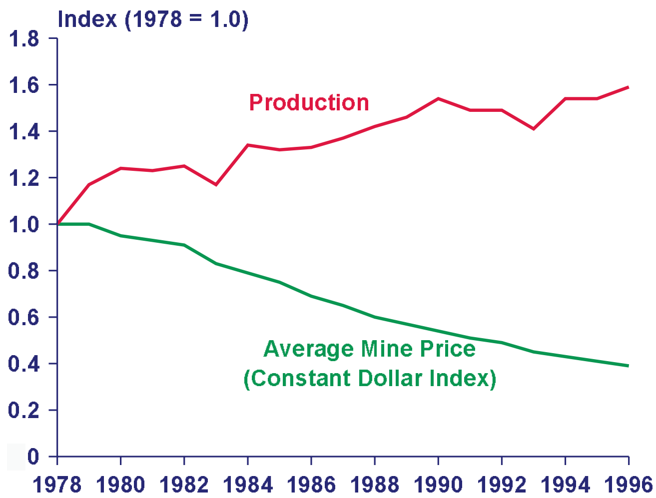
$$PCAP = [r + \delta - ((p_t - p_{t-1}) / p_{t-1})] p_t \quad ,$$

where r is a proxy for the real rate of interest, equal to the yield on utility bonds minus the percentage change in the implicit GDP deflator; δ is the rate of depreciation on mining equipment, assumed to equal 10 percent; and p_t is the PPI for coal mining equipment, adjusted to constant 1992 dollars using the GDP deflator. The three terms represented in the annual user cost of mining equipment are defined as follows: rp_t is the opportunity cost of having funds tied up in mine capital equipment; δp_t is the compensation to the mine owner for depreciation; and $((p_t - p_{t-1})/p_{t-1})p_t$ is the capital gain on mining equipment (in a period of declining capital prices, this term will take on a negative value, increasing the user cost of capital for year t).

Trends

Between 1978 and 1996, the average mine price of coal in the United States declined by 61 percent, in constant 1996 dollars, from $47.31 per ton in 1978 to $18.50 per ton in 1996 (Figure 2). During the same period, total U.S. coal production increased by 59 percent, from 680 million tons in 1978 to 1,064 million tons in 1996. The inverse relationship between the production of coal and its price over time is attributable to a host of factors, including gains in labor productivity and declines in factor input costs.

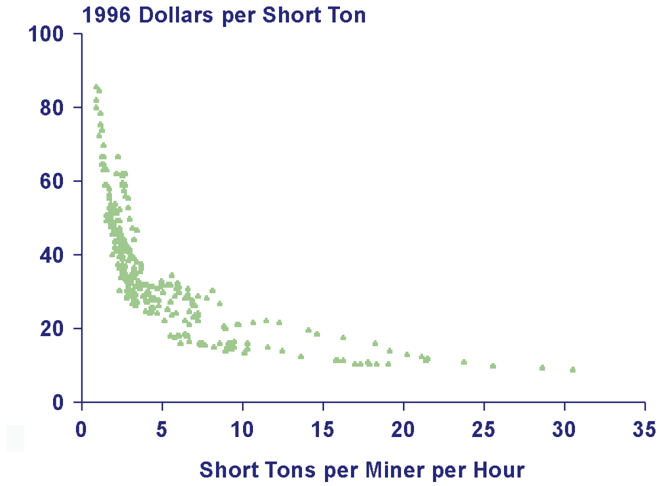
Figure 2. U.S. Coal Production and Prices, 1978-1996



Source: Energy Information Administration, Form EIA-7A, "Coal Production Report."

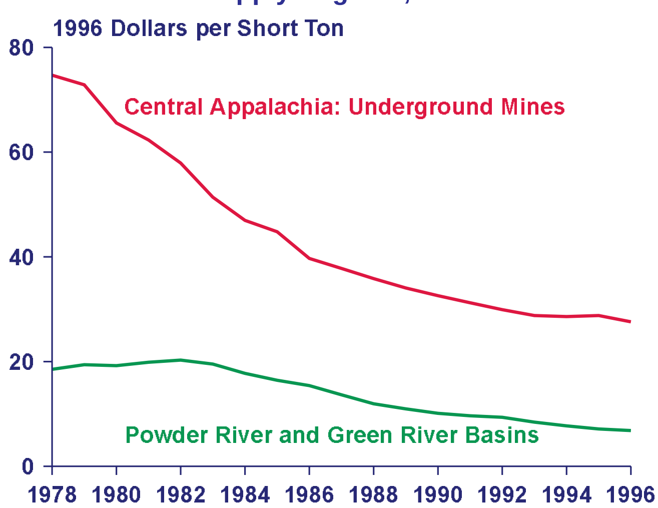
Productivity has had a profound effect on competition in the U.S. coal industry. Between 1978 and 1996, labor productivity at U.S. mines rose from 1.77 tons per miner hour to 5.69 tons per miner hour, representing an increase of 6.7 percent per year. This growth contributed to a downward shift in costs over time, making additional quantities of coal available at lower prices. A graphical representation of labor productivity and the average price of coal at mines for the observations (unique combinations of region, mine type, and year) represented in the *AEO98* coal pricing model indicates the strong historical correlation between prices and productivity (Figure 3). Figures 4 and 5 show the price and productivity data for two key coal-producing regions, Central Appalachia (underground mines) and the Powder River Basin. In 1996, these regions accounted for 16 percent and 30 percent of total U.S. coal production, respectively.

Figure 3. Minemouth Coal Prices and Labor Productivity for CMM Regions and Mine Types, 1978-1996



Source: Energy Information Administration, Form EIA-7A, "Coal Production Report."

Figure 4. Average Mine Price of Coal for Selected CMM Supply Regions, 1978-1996



Note: Includes data for all coal produced in Wyoming and Montana.

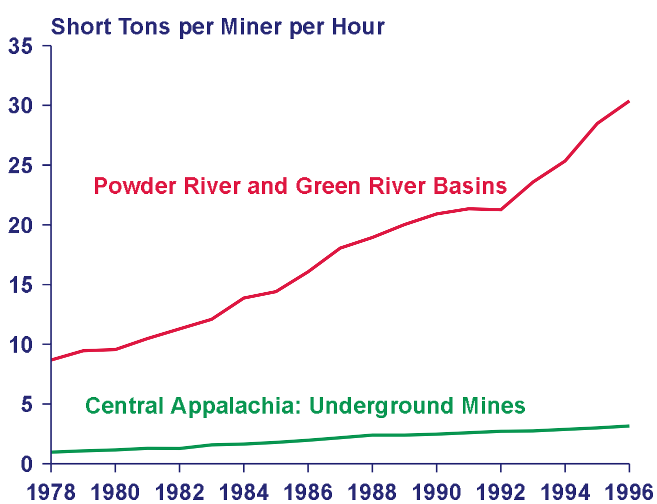
Source: Energy Information Administration, Form EIA-7A, "Coal Production Report."

The large differences in productivity and price levels between regions reflect, to a large extent, the substantial geologic variation in mining conditions. Underground mines in Central Appalachia operate in relatively thin coal seams (average thickness of 4.7 feet in 1996) and generally employ continuous mining equipment to extract the coal. In the underground mines of Northern Appalachia and the Rocky Mountain region, thicker seams (5.8 and 10.7 feet, respectively, in 1996) are more amenable to the use of more efficient longwall mining equipment. In 1996, longwall mines accounted for only 18 percent of the coal produced from underground mines in Central Appalachia, as compared with 77 and 86 percent of the coal produced from underground mines in the Northern Appalachia and Rocky Mountain regions, respectively.

The surface mines of the Powder River Basin have large reserves of low-Btu, low-sulfur coal in very thick seams (average thickness of 61.2 feet in 1996) with low overburden ratios (cubic yards of overburden per ton of coal contained in the seam). Although production costs are very low, the region's coal is situated far from the major coal markets and has only recently been able to compete with higher ranked coals from the Eastern Interior and Appalachian regions. Declining coal transportation rates and restrictions on emissions of sulfur dioxide at electric utility plants are other important factors that help to explain the rapid rise in the region's share of total U.S. coal production, from 13 percent in 1978 to 30 percent in 1996.

Factor input costs follow a significantly different path over time from that of labor productivity (Figure 6). Diesel fuel prices and the user cost of mining equipment and machinery have declined considerably since the mid-1980s, but they have increased sharply in prior years of the decade. Annual coal industry wages in constant dollars have varied by only minor amounts since 1984. In 1996, average annual wages in the coal industry (in constant dollars) were only 13 percent above the 1978 level. Figure 7 compares national-level annual wage data with regional-level data for Central Appalachia and the Powder River Basin. This figure indicates that while

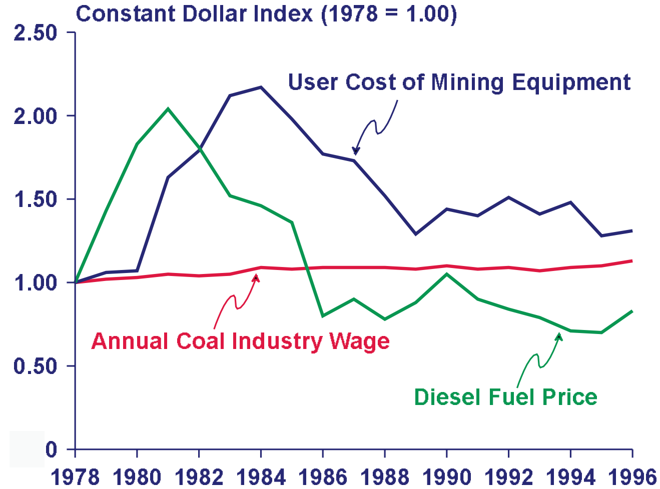
Figure 5. Average Coal Mine Labor Productivity for Selected CMM Supply Regions, 1978-1996



Note: Includes data for all coal produced in Wyoming and Montana.

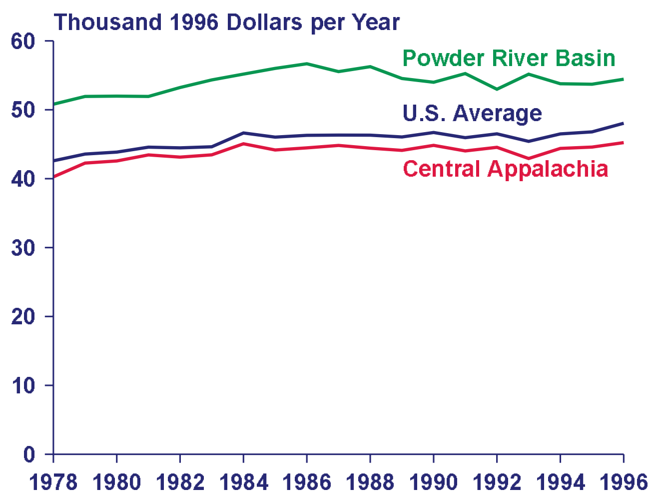
Source: Energy Information Administration, Form EIA-7A, "Coal Production Report."

Figure 6. Diesel Fuel Prices, Annual Coal Industry Wages, and User Cost of Mining Equipment, 1978-1996



Sources: **Diesel Fuel Price:** Energy Information Administration, *Petroleum Marketing Annual 1996*, DOE/EIA-0487(96) (Washington, DC, October 1997), Table 2 (No. 2 Diesel Fuel). **User Cost of Mining Equipment:** U.S. Department of Labor, Bureau of Labor Statistics, *Producer Price Index (PPI) for Mining Machinery and Equipment*, Series PCU3532#; and Data Resources, Inc., *Yield on Utility Bonds*. **Annual Coal Industry Wage:** U.S. Department of Labor, Bureau of Labor Statistics, ES-202 Program, "Covered Employment and Wages."

Figure 7. Average Annual Wage in the U.S. Coal Industry for Selected CMM Supply Regions, 1978-1996



Note: The average annual wage for the Central Appalachian region includes wages paid to all coal industry personnel covered by the ES-202 Program in the States of West Virginia, Kentucky, and Virginia. The average annual wage for the Powder River Basin region includes wages paid to all coal industry personnel covered by the ES-202 Program in the States of Wyoming and Montana.

Source: U.S. Department of Labor, Bureau of Labor Statistics, ES-202 Program, "Covered Employment and Wages."

mine wages vary substantially by region, the overall trends in wages follow a similar path over time (i.e., rising over the early years of the historical period but remaining constant during the later years).

Description of the Econometric-Based Coal Pricing Methodology

The primary criteria guiding the development of the *AEO98* coal pricing model were that the model should conform to economic theory and that parameter estimates should be unbiased and statistically significant.[10] Following economic theory, an increase in output or factor input prices should result in higher minemouth prices, and increases in coal mining productivity should result in lower minemouth prices. In addition, the model should account for a substantial portion of the variation in minemouth prices over the historical period of study.

The model of the U.S. coal market developed for the CPS recognizes that prices in a competitive market are a function of factors that affect both the supply and demand for coal. The general form of the model is that a competitive market converges toward equilibrium, where the quantity supplied equals the quantity demanded:

$$Q^S_{i,j,t} = Q^D_{i,j,t} = Q_{i,j,t} \quad .$$

In this equality, $Q_{i,j,t}$ represents the long-run equilibrium between supply and demand in a competitive market.

The formal specification of the coal pricing model for *AEO98* is as follows. For demand:

$$\begin{aligned} Q^D = f(&P, TRAN, ELEC, INDUSTRY, \\ &OTHPROD, EXPORTS, PGAS, \\ &WOP, STOCKS, BTU\_TON, \\ &CAA) + e^D \quad . \end{aligned} \qquad (1)$$

For supply:

$$P = f(Q^S, TPH, WAGE, PCAP, PFUEL) + e^S \quad . \qquad (2)$$

The demand-side variables are as follows:

Q^D is the quantity of coal demanded from region *i*, mine type *j*, in year *t* in million tons.

TRAN is a producer price index for the cost of transporting coal in region *i* to the regions where it is consumed for each year *t*. The index is adjusted to constant 1992 dollars.

ELEC is an index of electricity generation requirements for each year *t*.

INDUSTRY is an index of industrial output for each year *t*.

OTHPROD is the total U.S. coal production in million tons minus coal production for region *i* and mine type *j* for each year *t*.

EXPORTS is the level of U.S. coal exports in million tons in year *t*-1.

PGAS is the delivered price of natural gas to the utility sector in constant 1992 dollars per thousand cubic feet.

WOP is the world oil price in constant 1992 dollars per barrel in year *t*.

STOCKS is the quantity of coal inventories held by U.S. electric utilities in million tons at the beginning of year *t*.

BTU_TON is the average heat content of coal receipts at electric utility plants in million Btu per ton for region *i* in year *t*.

CAA is a dummy variable representing the impact of the Clean Air Act Amendments of 1990, equal to 1 if year is greater than 1990, and zero otherwise.

e^D is a random error term corresponding to the demand function for region *i* and mine type *j* in year *t*.

The supply-side variables are as follows:

P is the minemouth price of coal in constant 1992 dollars for region *i* and mine type *j* in year *t*.

Q^S is the quantity of coal supplied from region *i*, mine type *j*, in year *t* in million tons.

TPH is the average annual labor productivity of coal mines in tons per miner hour for region *i* and mine type *j* in year *t*.

WAGE is the average annual coal industry wage in constant 1992 dollars for region *i* in year *t*.

PCAP is an index representing the annualized user cost of mining equipment in year *t*. The index is adjusted to constant 1992 dollars.

PFUEL is the average annual refiner price of No. 2 diesel fuel to end users in constant 1992 cents per gallon in year *t*.

e^S is a random error term corresponding to the supply function for region *i* and mine type *j* in year *t*.

In this model, the amount of coal demanded from region *i* and mine type *j* in year *t* is determined by the minemouth price of coal, the cost of transporting the coal to market, electricity generation, industrial output, coal

[10]Dr. Kevin Forbes, Science Applications International Corporation, formulated and estimated the Two-Stage Least Squares model of the U.S. coal market used for *AEO98*. This section draws upon material provided in the report by Science Applications International Corporation, *An Econometric Model of Coal Supply: Final Report*, prepared for the Energy Information Administration (December 20, 1996).

exports, the total quantity of coal produced in other regions, the price of natural gas, the world oil price, the level of coal stocks, the heat content of the coal, and the regulatory regime as proxied by the passage of the Clean Air Act Amendments of 1990 (CAAA90). On the supply side of the market, the minemouth price is assumed to be determined by the quantity of coal produced, the level of labor productivity, the average level of wages, the annualized cost of mining equipment, and the cost of fuel used by mines.

Estimation Methodology

The supply function for coal cannot be evaluated in isolation when the relationship between quantity and price is being studied. The solution is to bring the demand function into the picture and estimate the demand and supply functions together. For the *AEO98* coal pricing model, the two-stage least squares (2SLS) methodology was selected for estimating the set of simultaneous equations representing the supply and demand for coal.

The rationale for using 2SLS rather than ordinary least squares (OLS) results from the structure of equations (1) and (2). In equation (2), the error term in the supply equation (e^S) affects the minemouth price (P); however, in Equation (1), price influences the quantity demanded (Q^D). As a result, the quantity of coal supplied (Q^S) on the right-hand side of the supply equation is correlated with the error term in the same equation. This violates one of the fundamental assumptions underlying the use of OLS, namely, that the error term is independent from the regressors. As a result, the OLS estimator will not be consistent.

In addition, while *WAGE*, *PCAP*, and *TPH* are all hypothesized to affect the price of coal, they are also affected by the price of coal. For example, an increase in the price of coal resulting from increased demand for coal may affect the wages paid in the coal industry, as well as the cost of mining equipment. Prices may also influence the level of productivity. If prices decrease (increase), marginal mines are abandoned (opened), increasing (lowering) labor productivity. This violates the assumption underlying the use of OLS, making it an inappropriate method by which to estimate the supply function.

An accepted solution to the problem of biased least squares estimators is the use of 2SLS, where the objective is to make the explanatory endogenous variable uncorrelated with the error term.[11] This is accomplished in two stages. In the first stage of the estimation, the endogenous explanatory variables are regressed on the exogenous and predetermined variables. This stage produces predicted values of the endogenous explanatory variables that are uncorrelated with the error term. The predicted values are employed in the second stage of the technique to estimate the relationship between the dependent endogenous variable and the independent variables. The results from the second-stage (structural) equation represents the model implemented in the CMM for *AEO98*. The first stage (reduced form) equations are used only to obtain the predicted values for the endogenous explanatory variables included in the second stage, effectively purging the demand effects from the supply-side variables.

The structural equation for the coal pricing model was specified in log-linear form using the variables listed above. In this specification, the values for all variables (except the constant term) are transformed by taking their natural logarithm. All 255 observations were pooled into a single regression equation. In addition to the overall constant term for the model, intercept dummy variables were included for all regions except Central Appalachia. Regional slope dummy variables were included for the productivity and production variables to allow the coefficients for those terms to vary across regions and mine types. The Durbin-Watson test for first-order positive autocorrelation indicated that the hypothesis of no autocorrelation should be rejected. As a consequence, a correction for serial correlation was incorporated. The statistical results of the regression analysis and the equation used for predicting future levels of minemouth coal prices by region, mine type, and coal type are provided in the Appendix.

In general, the results satisfy the performance criteria specified for the model. Indicative of the high R^2 statistic, there is a close correspondence between the predicted and actual minemouth prices. Moreover, all parameter estimates have their predicted signs and, with the exception of the diesel fuel price term, are generally statistically significant. Some of the regional and mine type specific variables for the productivity term are insignificant, but in most cases the parameter estimates for these variables are relatively small.

Average annual seam thickness by region and mine type also was tested as a supply-side variable. The model results, however, did not support the hypothesis that decreases (increases) in seam thickness have exerted upward (downward) pressure on prices.

AEO98 Results

For *AEO98*, the econometric pricing equation together with projected levels of labor productivity, miner wages, capital costs, fuel prices, and lagged minemouth coal prices were used to estimate minemouth prices of coal by region, mine type, and coal type for different levels of production. Current and lagged (one-year) projections of the explanatory variables were obtained from other components of NEMS or were supplied as exogenous inputs. Projected values for coal production and the

[11] G.S. Maddala, *Introduction to Econometrics: Second Edition* (New York, NY: Macmillan Publishing Company, 1992), Chapter 9.

lagged minemouth coal price were obtained from the Coal Distribution Submodule, and diesel fuel prices were supplied by the Petroleum Market Module of NEMS. Projected values for the remaining factors (labor productivity, wages, and the user cost of capital) were supplied as exogenous inputs.

In the reference case, wages and the user cost of capital are assumed to remain unchanged in constant dollars. Productivity improvements are assumed to continue but to decline in magnitude over the forecast period. On a national basis, labor productivity increases at an average rate of 2.0 percent per year over the whole forecast, declining from an annual rate of 5.8 percent in 1996 to a rate of approximately 1.6 percent per year over the 2010 to 2020 period.

The forecasts of labor productivity (in short tons per miner hour) and the minemouth price of coal are shown in Figures 8 and 9. In the *AEO98* reference case, the national-level minemouth coal price is projected to fall from $18.50 per ton in 1996 to $13.27 per ton by 2020, a decline of 1.4 percent per year. This price drop reflects both regional changes in production patterns and changes in factors affecting the costs of production, primarily increases in productivity. In the reference case, approximately 40 percent of the projected price decline is due to regional changes in production, and the remainder is accounted for by factors affecting the costs of production.

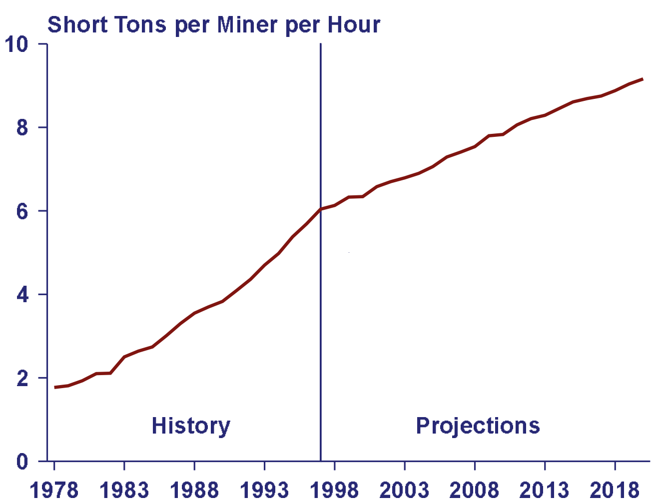
Figures 10 and 11 show price and productivity projections for two representative supply curves: medium-sulfur steam coal from underground mines in Central Appalachia, and low-sulfur subbituminous coal from surface mines in the Powder River Basin. These figures clearly demonstrate the inverse relationship between productivity and price as represented in the coal pricing equation.

For the Central Appalachia supply curve, prices are projected to decline by 0.7 percent per year, from $26.15 per ton in 1996 to $22.07 per ton in 2020. Productivity increases by 1.1 percent per year, from 3.16 tons per hour in 1996 to 4.09 tons per hour in 2020. Production remains relatively unchanged, increasing from 70 million tons in 1996 to 83 million tons in 2000, but returning to 70 million tons in 2020.

The regression coefficient for the labor productivity term for Central Appalachian underground mines is –0.728.[12] This coefficient indicates that a 1-percent increase in labor productivity will result in a 0.728-percent decline in the minemouth price of coal, all other factors held constant. In the *AEO98* reference case, a 1-percent increase in labor productivity for the Central Appalachian supply curve corresponds to a somewhat lower price decline of 0.65 percent. The slightly reduced effect on prices reflects the additional impacts from changes in production and diesel fuel prices and the moderating effects of the lagged terms incorporated to correct for serial correlation.

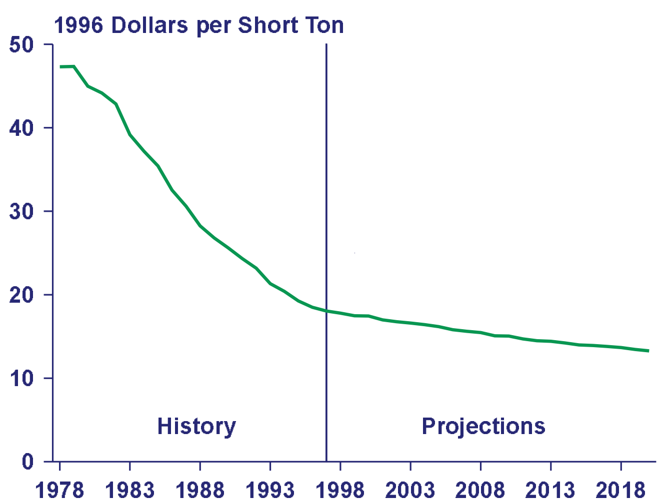
For the Powder River Basin supply curve, prices are projected to decline by 0.7 percent per year, from $6.43 per ton in 1996 to $5.41 per ton in 2020. Productivity

Figure 8. Average Labor Productivity at U.S. Coal Mines, 1978-2020



Sources: **History:** Energy Information Administration, Form EIA-7A, "Coal Production Report." **Projections:** Energy Information Administration, AEO98 National Energy Modeling System, run AEO98B.D100197A.

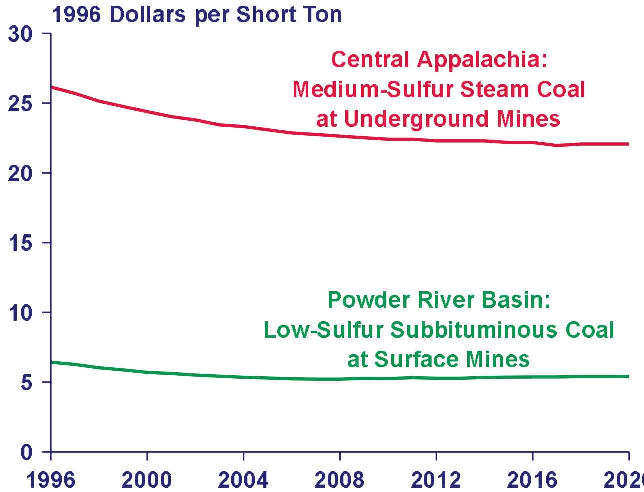
Figure 9. Average Price of Coal at U.S. Mines, 1978-2020



Sources: **History:** Energy Information Administration, Form EIA-7A, "Coal Production Report." **Projections:** Energy Information Administration, AEO98 National Energy Modeling System, run AEO98B.D100197A.

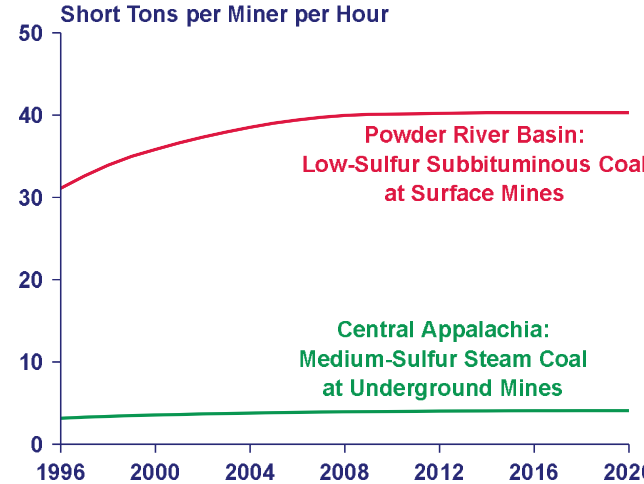
[12]The regression coefficient for the labor productivity term for Central Appalachian underground mines is equal to the overall coefficient for labor productivity plus the labor productivity coefficient for underground mines plus the *AEO98* adjustment (-0.728 = -0.953 + 0.051 + 0.174).

Figure 10. Average Mine Price of Coal for Selected CMM Supply Curves, 1996-2020



Source: Energy Information Administration, AEO98 National Energy Modeling System, run AEO98B.D100197A.

Figure 11. Average Coal Mine Labor Productivity for Selected CMM Supply Curves, 1996-2020



Source: Energy Information Administration, AEO98 National Energy Modeling System, run AEO98B.D100197A.

increases by 1.1 percent per year, from 31.11 tons per hour in 1996 to 40.29 tons per hour in 2020. Production more than doubles, increasing from 281 million tons in 1996 to 568 million tons in 2020.

The regression coefficient for the labor productivity term for Powder River Basin surface mines is -0.996.[13] This coefficient indicates that a 1-percent increase in labor productivity will result in a 0.996-percent decline in the minemouth price of coal, all other factors held constant. For the Powder River Basin supply curve shown in Figures 10 and 11, a 1-percent increase in labor productivity corresponds to a decline in the minemouth coal price of 0.66 percent. A larger decline in the minemouth price of coal would have been projected for this region and coal type had not coal production for the supply curve doubled over the forecast period. Because the regression coefficient for the production term for Powder River Basin surface mines is 0.117, a 1-percent increase in production results in a 0.117-percent increase in the minemouth price of coal.

Post-*AEO98* Updates and Revisions

Database Updates and Revisions

Following the completion of *AEO98*, work was initiated to improve the quality of the database that will be used to update the regression for *AEO99*. Data for 1995 and 1996 will be added as will additional data series for sulfur content, utility shipments by type of purchase (spot and contract), and electricity prices.

Data for coal minemouth prices, labor productivity, and production, originally entered from data published in various issues of *Coal Production* and the *Coal Industry Annual*, will be replaced with data obtained directly from the EIA-7A, "Coal Production Report," database files. Likewise, data for utility receipts of coal (quantities and average quality) will be obtained directly from the Federal Energy Regulatory Commission (FERC) Form-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," database files. This will provide a more precise measure of the data for Northern Appalachia, Central Appalachia, and the Eastern Interior regions, for which disaggregation of State-level data is required. Coal data for northern and southern West Virginia and for eastern and western Kentucky are not consistently available in EIA publications. In addition, coal quality data for receipts of coal at electric utility plants by State of origin are not published by mine type but are available from the FERC Form-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," database files.

Future Work

Future work will include the examination and reestimation of the coal pricing equation using the additional years of data and the new and updated variables in the database. Data on electricity prices will be tested as a replacement for the price of diesel fuel, which was not statistically significant in the pricing equation developed for *AEO98*. According to data published by the U.S. Department of Commerce, electricity accounted for 84 percent of the fuel costs at U.S. underground mines in 1992 and an estimated 36 percent of the fuel costs at surface mines.[14] Electric utility data on the average sulfur content of coal and receipts of coal by type of purchase will be tested as instruments in the first stage of the regression, as additional factors hypothesized to affect the demand for coal by region and mine type.

[13] The regression coefficient for the labor productivity term for Powder River Basin surface mines is equal to the overall coefficient for labor productivity plus the regional productivity coefficient for the Powder River Basin plus the *AEO98* adjustment (-0.996 = -0.953 - 0.217 + 0.174).

[14] U.S. Census Bureau, *1992 Census of Mineral Industries*, web site www.census.gov (accessed April 9, 1998).

Appendix A
Regression Results and the *AEO98* Coal Pricing Equation

The two-stage least squares regression equation for the Coal Production Submodule was estimated using the AR1 (first-order serial correlation) procedure in TSP 4.4 with the INST option. Based on the regression results shown in Table A1, the equation used for predicting future levels of minemouth coal prices by region, mine type and coal type for *AEO98* is:

$$\begin{aligned} P_{i,j,k,t} = \psi_{i,j,k,t} + [& C_{i,j,k,t} \times Q_{i,j,k,t}^{(\beta_2 + \beta_{j,3})} \\ & \times TPH_{i,j,t}^{((\beta_4 + (k \times SE)) + \beta_{i,5} + \beta_{j,6} + \beta_{i,j,7})} \times WAGE_{i,t}^{\beta_8} \\ & \times PCAP_t^{\beta_9} \times PFUEL_t^{\beta_{10}} \times P_{i,j,k,t-1}^{\beta_{11}} \times Q_{i,j,k,t-1}^{-\beta_{11} \times (\beta_2 + \beta_{j,3})} \\ & \times TPH_{i,j,t-1}^{(-\beta_{11} \times ((\beta_4 + (k \times SE)) + \beta_{i,5} + \beta_{j,6} + \beta_{i,j,7}))} \\ & \times WAGE_{i,t-1}^{(-\beta_{11} \times \beta_8)} \times PCAP_{t-1}^{(-\beta_{11} \times \beta_9)} \\ & \times PFUEL_{t-1}^{(-\beta_{11} \times \beta_{10})}] \ , \end{aligned}$$

where $\psi_{i,j,k,t}$ is a constant added to the regression equation for each supply region *i*, mine type *j*, and coal type *k* in each year *t* to calibrate the model to current price levels. For *AEO98*, prices were calibrated to the average annual mine prices for 1996:

$$C_{i,j,k,t} = e^{(A + \beta_{i,1}) \times (1 - \beta_{11})} \times TPH_{i,j,t=1}^{(k \times -SE \times (1 - \beta_{11}))} \ ,$$

where:

The first term ($e^{(A + \beta_{i,1}) \times (1 - \beta_{11})}$) is the intercept for the model. It includes the overall constant for the model (A) and the regional specific constants ($\beta_{i,1}$).

The second term ($TPH_{i,j,t=1}^{(k \times -SE \times (1 - \beta_{11}))}$) is a required component of a feature added to the model. This feature provides the ability to adjust the overall coefficient for the labor productivity term for modeling runs of the Coal Market Module. Specifically, the term *k* is the parameter by which the adjustment is made. The *SE* term is the standard error of the parameter estimate (β_4) for the labor productivity term and is a constant. For *AEO98*, *k* was set equal to 2, reflecting the assumption that coal mine operators will not continue to pass along cost savings obtained through productivity improvements to the same extent that they have during the past 15 years. The basis for this assumption is that, as a result of strong competitive pressures, the coal industry has been realizing a lower rate of return than other comparative industries in recent years. Therefore, coal industry earnings need to improve somewhat in order to continue to attract sufficient amounts of investment.

The regression coefficients are as follows:

A is the overall constant for the model

$\beta_{i,1}$ for the intercept dummy variables for each supply region *i*

β_2 for the production term

$\beta_{j,3}$ for the production term by mine type *j*

β_4 for the labor productivity term

$\beta_{i,5}$ for the labor productivity term by supply region *i*

$\beta_{j,6}$ for the labor productivity term by mine type *j*

$\beta_{i,j,7}$ for the labor productivity term by supply region *i* and mine type *j*

β_8 for the labor cost term

β_9 for the user cost of capital term

β_{10} for the diesel fuel term

β_{11} for the first-order autocorrelation term.

Table A1. Regression Statistics for the Coal Pricing Model

Regression Coefficient	Variable	Parameter Estimate	Standard Error	t-Statistic
A	Overall Constant	0.211	1.864	0.113
$\beta_{i=1,1}$	DUM_REG_1 (Northern Appalachia (NA))	-0.043	0.075	0.578
$\beta_{i=2,1}$	DUM_REG_2 (Southern Appalachia (SA))	-0.002	0.102	0.023
$\beta_{i=3,1}$	DUM_REG_3 (East Interior (EI))	0.038	0.098	0.390
$\beta_{i=4,1}$	DUM_REG_4 (West Interior (WI))	0.145	0.155	0.933
$\beta_{i=5,1}$	DUM_REG_5 (Gulf Lignite (GL))	-0.926	0.293	3.160*
$\beta_{i=6,1}$	DUM_REG_6 (Dakota Lignite (DL))	0.127	0.280	0.453
$\beta_{i=7,1}$	DUM_REG_7 (Powder River Basin (PG))	1.108	0.247	4.494*
$\beta_{i=8,1}$	DUM_REG_8 (Rocky Mountain (RM))	0.041	0.126	0.326
$\beta_{i=9,1}$	DUM_REG_9 (Arizona/New Mexico (ZN))	-0.746	0.320	2.330**
β_2	ln Q	0.117	0.045	2.607*
$\beta_{j=1,3}$	DUM_MT (Underground) * ln Q	-0.069	0.019	3.719*
β_4	ln TPH	-0.953	0.087	10.933*
$\beta_{i=1,5}$	NA*ln TPH	-0.093	0.081	1.149
$\beta_{i=2,5}$	SA*ln TPH	0.522	0.083	6.259*
$\beta_{i=3,5}$	EI*ln TPH	0.010	0.083	0.119
$\beta_{i=4,5}$	WI*ln TPH	-0.002	0.165	0.012
$\beta_{i=5,5}$	GL*ln TPH	0.445	0.159	2.799*
$\beta_{i=6,5}$	DL*ln TPH	0.076	0.118	0.646
$\beta_{i=7,5}$	PG*ln TPH	-0.217	0.114	1.903***
$\beta_{i=8,5}$	RM*ln TPH	0.292	0.076	3.826*
$\beta_{i=9,5}$	ZN*ln TPH	0.711	0.174	4.075*
$\beta_{j=1,6}$	DUM_MT (Underground) * ln TPH	0.051	0.102	0.503
$\beta_{i=1,j=1,7}$	NA * DUM_MT (Underground) * ln TPH	0.253	0.055	4.608*
$\beta_{i=1,j=2,7}$	SA * DUM_MT (Underground) * ln TPH	-0.315	0.079	4.018*
$\beta_{i=1,j=3,7}$	EI * DUM_MT (Underground) * ln TPH	0.048	0.069	0.694
$\beta_{i=1,j=8,7}$	RM * DUM_MT (Underground) * ln TPH	-0.099	0.070	1.424
β_8	ln WAGE	0.318	0.177	1.802***
β_9	ln PCAP	0.116	0.032	3.667*
β_{10}	ln PFUEL	0.007	0.024	0.308
β_{11}	Autocorrelation Parameter (Rho)	0.414	0.061	6.816*
	Adjusted R squared	0.990		
	Durbin-Watson Statistic	2.173		
	Number of Observations	225[a]		

[a]The Cochrane-Orcutt method was used to correct for the first-order serial correlation in the data. The use of this procedure on pooled time series-cross section data using the TSP 4.4 statistical package results in the loss or dropping of the first two observations for each group of data (combination of region and mine type). As a result, the regression only uses the observations for the years 1980 through 1994 (225 observations), excluding data for 1978 and 1979 (30 observations).

*Significant at 1 percent.

**Significant at 5 percent.

***Significant at 10 percent.

Notes: The endogenous explanatory variables in the regression are *Q*, *TPH*, *WAGE*, *PCAP*, and *PFUEL*. Instruments excluded from the supply equation are the index of electric utility generation, the index of industrial production, lagged exports, coal inventories at utility plants, lagged production, lagged mine price of coal, lagged mine productivity, a time trend, the world oil price, the price of natural gas to the electric sector, the Btu content of coal, the cost of coal transportation, and a dummy variable that proxies the impact of the Clean Air Act on coal demand.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Annual Energy Outlook Forecast Evaluation

by
Susan H. Holte and Eugene J. Reiser

This paper evaluates the projections in the Annual Energy Outlook *(*AEO*),*[1] *by comparing the projections from the* Annual Energy Outlook 1982 *through the* Annual Energy Outlook 1998 *with actual historical values and providing the rationale for the differences. A set of 16 major consumption, production, imports, price, and economic variables were chosen for evaluation, updating a similar analysis published in the previous edition of* Issues in Midterm Analysis and Forecasting.[2] *This paper expands on the previous one by adding the most recent* AEO *to the evaluation, including 1997 as an additional historical year, adding a comparison of high and low economic growth cases when available, and including a regression analysis of the historical data.*

Introduction

This paper presents an analysis of the forecast record of the *Annual Energy Outlook* (*AEO*). It compares the projections for major energy variables from the reference case for each of the *AEO*s published from April 1983 through December 1997 with actual data.[3] The purpose of the analysis is to provide a measure of the accuracy of the forecasts; however, prediction of future energy markets is not the primary reason for developing and maintaining the models that the Energy Information Administration (EIA) uses to produce the *AEO*. Because the EIA models are developed primarily as tools for policy analysis, a key assumption of the forecasts is that current laws and regulations will remain in effect throughout the forecast horizon. This assumption, while necessary to provide a baseline against which changes in policy can be evaluated, also virtually guarantees that the forecasts will be in error, as laws and regulations pertinent to energy markets change considerably over the years.

The National Energy Modeling System (NEMS)—the current EIA model used to produce the midterm projections in the *AEO*—and the predecessor models were designed to enforce a discipline on the process of energy market analysis by providing a comprehensive set of assumptions that are consistent with our understanding of the factors that affect energy markets—for example, technological innovation, energy service demand growth, and energy resources. The models are modified each year to ensure their relevance to evolving energy issues and to update baseline data, parameters, and assumptions with the most recent historical data. NEMS, first used for the *Annual Energy Outlook 1994* (*AEO94*),[4] was specifically designed for a high level of technological detail and flexibility to address a wide range of policy options.

These models are frequently used in studies conducted for the U.S. Congress, the Department of Energy, and other Government agencies to analyze the impacts of changes in energy policies, regulations, and other major assumptions on future energy supply, demand, and prices, typically using assumptions specified by the client. The most recent examples of analytical studies include an analysis of the Electric System Public Benefits Protection Act of 1997[5] at the request of Senator James M. Jeffords (R-Vt), Chairman of the Senate Committee on Labor and Human Resources; a study of carbon reduction policies[6] for the U.S. Department of Energy, Office of Policy and International Affairs; a study on the costs and economic impacts of oil imports[7] for the U.S. General Accounting Office; an analysis for Senator Jeffords on open access regulatory changes and their impacts on the electricity industry;[8] and an analysis of

[1]See Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), for the most recent *AEO*.

[2]Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1997*, DOE/EIA-0607(97) (Washington, DC, July 1997).

[3]For an analysis of EIA's record for forecasts made from 1977 through 1993, see B. Cohen, G. Peabody, M. Rodekohr, and S. Shaw, "A History of Mid-Term Energy Projections: A Review of the Annual Energy Outlook Projections" (unpublished manuscript, February 1995).

[4]Energy Information Administration, *Annual Energy Outlook 1994*, DOE/EIA-0383(94) (Washington, DC, January 1994).

[5]Energy Information Administration, *Analysis of S. 687, the Electric System Public Benefits Protection Act of 1997*, SR/OIAF/98-01 (Washington, DC, February 1998).

[6]Energy Information Administration, *Analysis of Carbon Stabilization Cases*, SR-OIAF/97-01 (Washington, DC, October 1997).

[7]Energy Information Administration, *The Impacts on U.S. Energy Markets and the Economy of Reducing Oil Imports*, SR-OIAF-96-04 (Washington, DC, September 1996).

[8]Energy Information Administration, *An Analysis of FERC's Final Environmental Impact Statement for Electricity Open Access and Recovery of Stranded Costs*, SR-OIAF/96-03 (Washington, DC, September 1996).

carbon mitigation policies[9] prepared for the U.S. Environmental Protection Agency.

Just in the period analyzed in this paper, many legislative actions and policies have been enacted, including the National Appliance and Energy Conservation Act of 1987, the Natural Gas Wellhead Decontrol Act of 1989, the Clean Air Act Amendments of 1990 (CAAA90), the Energy Policy Act of 1992, the repeal of the Power Plant and Industrial Fuel Use Act of 1978 (FUA), the North American Free Trade Agreement, the Omnibus Budget Reconciliation Act of 1993, the Outer Continental Shelf Deep Water Royalty Relief Act of 1995, the Tax Payer Relief Act of 1997, the Climate Change Action Plan developed by the Clinton Administration in 1993 to achieve stabilization of greenhouse gas emissions, and various orders issued by the Federal Energy Regulatory Commission (FERC). Examples of FERC orders include Order 636, which restructured interstate natural gas pipeline companies and required the separation of sales and transportation functions, and Orders 888 and 889, which provided open access to interstate electricity transmission lines. These actions have had significant impacts on energy supply, demand, and prices, but because of the assumption on current laws and regulations, the impacts were not incorporated in the *AEO* projections until their enactment or effective dates.

In several cases, EIA's models have been used to evaluate some of the potential impacts of these changes in laws and regulations before they were enacted, thus fulfilling EIA's designated role in policy analysis. For example, EIA provided comprehensive analysis to the House Energy and Commerce Committee concerning the impacts of the CAAA90 on the coal and electricity industries. In other cases, the models have been used to analyze policies that were eventually rejected; a prime example is the British thermal unit (Btu) tax proposed in early 1993. Both of these uses of the models illustrate the importance of maintaining a modeling capability apart from the forecasting function, using current laws and regulations as a baseline assumption.

In addition to changes in laws and regulations, a number of other factors can cause energy markets to deviate from the longer term trends represented by the forecasts in the *AEO*. For example, the forecasts assume normal weather patterns; however, the weather will rarely, if ever, be normal in any given year. Although the *AEO* models have not generally been used for analysis of weather conditions on energy markets, temperatures that are colder or warmer than normal for sustained periods have a significant impact on energy consumption. Strikes and political incidents, such as the Iraqi invasion of Kuwait in 1990, are other unanticipated events whose impacts on energy markets are not captured in a mid- to long-term energy projection. Any of these events can cause price volatility and fluctuations in energy consumption and supply. EIA's *Short-Term Energy Outlook* (*STEO*)[10] reflects the impacts of these events and the near-term adjustments to them, and each *AEO* adjusts its near-term forecasts to the most recent *STEO* projections. By presenting quarterly projections and accounting for stock fluctuations and other short-term adjustments, the *STEO* is more applicable to the analysis of such events than is the *AEO*, which presents annual average projections.

Although the primary purpose of the models is policy analysis, many users of the *AEO* view the projections as forecasts. Thus, analyzing the models' performance and the reasons for differences between the projections and history is important both for users and for those responsible for the projections. The models and assumptions used in the *AEO*s undergo continuous evaluation and change, in part because of changes in energy markets and in part as a result of internal assessment of the models' performance. Natural gas markets are an example of both points. The representation of natural gas markets has been revised significantly to reflect deregulation. In addition, the fundamental assumptions about the size and potential growth of natural gas resources have been revised because evaluations of past forecasts have shown that price projections for gas were too high.

This paper presents projections for each *AEO* from 1982 to 1998.[11] The forecast horizon has expanded over the period examined in this paper; for example, the *Annual Energy Outlook 1982* (*AEO82*)[12] projections of energy markets extended only through 1990. Also, although year-by-year forecasts were produced for each *AEO*, many *AEO*s published only selected years. This evaluation includes all projected years, including unpublished projections where available. A set of 16 key energy variables is used to provide a comprehensive picture of the projections. The projections in this analysis were produced by the models in use at the time. Before 1994, the Intermediate Future Forecasting System was the primary model for midterm projections; however, this evaluation is not meant to assess a specific model but rather to assess the forecasts and the underlying assumptions that shape the results. An evaluation of

[9]Energy Information Administration, *An Analysis of Carbon Mitigation Cases*, SR-OIAF/96-01 (Washington, DC, June 1996).

[10]The Short-Term Integrated Forecasting System (STIFS) provides quarterly forecasts of energy markets for up to 2 years in the future. The most recent projections are provided in Energy Information Administration, *Short-Term Energy Outlook, Third Quarter 1998*, DOE/EIA-0202(98/3Q) (Washington, DC, July 1998). Monthly updates are provided on the EIA web site at www.eia.doe.gov/forecasting_index.html.

[11]The *AEO*s published in the years 1983 through 1988 were titled as the *Annual Energy Outlook 1982* through the *Annual Energy Outlook 1987*. In 1989, the numbering scheme changed, and that year's report was titled the *Annual Energy Outlook 1989*. Thus, although a forecast has been published annually, there is no *Annual Energy Outlook 1988*.

[12]Energy Information Administration, *Annual Energy Outlook 1982*, DOE/EIA-0383(82) (Washington, DC, April 1983).

models is inappropriate at this point, because NEMS—a longer run model—was first used for the 1994 forecasts, and historical data for comparison are available only for four short-term years. In this case, the best effort is to compare the NEMS results with forecasts from other organizations, as is done in each *AEO*.

Overview

Table 1 provides a summary of the average absolute forecast errors,[13] expressed as percentage differences from actual, for each of the major variables included in this analysis.[14] As the table indicates, the forecasts of consumption, production, and economic variables have generally been the most accurate; net import projections have been less accurate; and the price projections[15] have been the least accurate when evaluated on the basis of average absolute percent errors.

Table 1. Average Absolute Percent Errors for *AEO* Forecasts, 1982-1998

Variable	Average Absolute Percent Error
Consumption	
Total Energy Consumption	1.7
Total Petroleum Consumption	2.9
Total Natural Gas Consumption	5.7
Total Coal Consumption	3.0
Total Electricity Sales	1.7
Production	
Crude Oil Production	4.3
Natural Gas Production	4.8
Coal Production	3.6
Imports and Exports	
Net Petroleum Imports	9.5
Net Natural Gas Imports	16.7
Net Coal Exports	22.8
Prices and Economic Variables	
World Oil Prices	51.3
Natural Gas Wellhead Prices	72.1
Coal Prices to Electric Utilities	35.3
Average Electricity Prices	11.0
Gross Domestic Product	5.0

AEO = Annual Energy Outlook.
Source: Tables 2 through 17.

Each of the consumption, production, and economic variables has been projected with an average absolute percent error of 5.7 percent or less. For both total energy consumption and total electricity sales, the most accurately projected variables during this period, the average absolute percent error is 1.7 percent. Average absolute percent errors for net imports range from 9.5 percent for petroleum to 22.8 percent for coal. For prices, forecasting has proven to be a much greater challenge. Average absolute percent errors for the world oil price, the price of coal to electric utilities, and the average natural gas wellhead price range from 35.3 to 72.1 percent over the period, with natural gas wellhead prices proving to have the highest error of the variables evaluated. Average electricity price projections, however, fared better, with an 11.0-percent average absolute percent error.

The following sections discuss the underlying results in some detail; however, it is clear that quantities are more amenable to the forecasting methods used in the *AEO* than are prices; that the errors in forecasting prices have not, in general, affected the accuracy of projected quantities; and that natural gas has tended to have the highest average forecast error within most categories—consumption, production, and prices. Some of the major factors leading to inaccurate forecasts include the assumption in the earlier *AEO*s that the Organization of Petroleum Exporting Countries (OPEC) cartel would maintain the market power and cohesiveness to set world oil prices; the decline of oil production in the former Soviet Union; underestimates of the impact of technology improvements on the production and prices of oil, natural gas, and coal; the impacts of changes in laws and regulations on natural gas prices; the treatment of fuel supply contract provisions for natural gas and coal as fixed and binding; and other events that have caused the actual trends to differ from projected long-term trends, as discussed above.

[13]The average absolute errors displayed in Table 1 are the average absolute percent errors for each variable shown in Tables 2 through 17. This measure is computed as the mean, or average, of all the absolute values of the percentage errors shown for each *AEO*, for each year projected, for a given variable.

[14]The forecast evaluation in this paper is only for the *AEO* reference cases, with the exception of a section on high and low economic growth cases. Each *AEO* has provided a range of projections, generally based on different assumptions for world oil prices and economic growth. In many cases, this range of forecasts has, in fact, encompassed the eventual outcome of the variables evaluated. In order to keep the analysis manageable, the focus is on the reference case projections.

[15]All *AEO*s have projected prices in real—inflation-adjusted—dollars. In this paper, all price projections have been converted to nominal dollars, using historical deflators, to facilitate comparison across reports.

Energy Consumption

Total Energy Consumption

Total energy consumption forecasts have shown a generally good track record for most of the *AEO* publications.[16] The overall average absolute percent error for the period examined here is 1.7 percent (Table 2), with the largest errors occurring in forecasts for the year 1996 (3.0 percent), and the smallest errors in forecasts for 1991 (0.9 percent).

In terms of the *AEO* publications, the *Annual Energy Outlook 1986 (AEO86)*[17] had the largest absolute and average absolute percent errors for total energy consumption, at 3.0 quadrillion Btu and 3.4 percent, respectively. There was a significant underestimate of energy consumption for most of the projected years in

Table 2. Total Energy Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Quadrillion Btu)														
AEO82	76.3	76.9	77.2	78.0	78.9	83.3								1.8
AEO83	75.2	76.8	78.3	79.6	80.7	84.6					89.5			1.2
AEO84	75.7	76.7	78.5	80.3	81.9	86.4					93.5			1.6
AEO85	74.8	75.8	77.1	78.4	79.5	83.3	84.2	85.2	85.9	86.7	87.7			1.4
AEO86		74.3	76.1	77.0	77.5	81.5	82.9	84.0	84.8	85.7	86.5	87.9	88.4	3.0
AEO87			76.2	77.2	78.8	82.8	83.9	85.3	86.4	87.5	88.4			1.5
AEO89				79.4	80.6	84.5	85.4	86.4	87.3	88.2	89.2	90.8	91.4	1.3
AEO90					80.8	85.4					91.9			0.9
AEO91						84.4	85.0	86.0	87.0	87.9	89.0	90.4	91.8	1.4
AEO92							84.7	87.0	88.0	89.2	90.5	91.4	92.4	1.1
AEO93								87.0	88.3	89.8	91.4	92.7	94.0	0.8
AEO94									88.0	89.5	90.7	91.7	92.7	0.9
AEO95										89.2	90.0	90.6	91.9	1.7
AEO96											90.6	91.3	92.5	1.5
AEO97												92.6	93.6	0.9
AEO98													94.7	0.5
Actual Value	**74.0**	**74.3**	**76.9**	**80.2**	**81.4**	**84.1**	**84.0**	**85.6**	**87.4**	**89.3**	**90.9**	**93.9**	**94.2**	
Average Absolute Error	**1.5**	**1.8**	**0.8**	**1.7**	**1.7**	**1.1**	**0.7**	**0.9**	**1.0**	**1.3**	**1.6**	**2.9**	**1.9**	**1.5**
(Percent Error)														
AEO82	3.1	3.5	0.4	-2.8	-3.1	-0.9								2.3
AEO83	1.6	3.4	1.8	-0.8	-0.9	0.6					-1.6			1.5
AEO84	2.3	3.2	2.1	0.1	0.6	2.7					2.8			2.0
AEO85	1.1	2.0	0.3	-2.3	-2.3	-0.9	0.2	-0.5	-1.7	-2.9	-3.6			1.6
AEO86		0.0	-1.0	-4.0	-4.8	-3.1	-1.3	-1.9	-3.0	-4.0	-4.9	-6.4	-6.2	3.4
AEO87			-0.9	-3.8	-3.2	-1.5	-0.1	-0.4	-1.1	-2.0	-2.8			1.8
AEO89				-1.0	-1.0	0.5	1.7	0.9	-0.1	-1.2	-1.9	-3.3	-3.0	1.5
AEO90					-0.7	1.6					1.1			1.1
AEO91						0.4	1.1	0.5	-0.5	-1.6	-2.1	-3.7	-2.5	1.5
AEO92							0.9	1.7	0.6	-0.2	-0.5	-2.6	-1.9	1.2
AEO93								1.7	1.0	0.6	0.5	-1.3	-0.2	0.9
AEO94									0.7	0.3	-0.2	-2.3	-1.6	1.0
AEO95										-0.1	-1.1	-3.5	-2.4	1.8
AEO96											-0.4	-2.8	-1.8	1.6
AEO97												-1.3	-0.7	1.0
AEO98													0.5	0.5
Average Absolute Percent Error	**2.1**	**2.4**	**1.1**	**2.1**	**2.1**	**1.4**	**0.9**	**1.1**	**1.1**	**1.4**	**1.8**	**3.0**	**2.1**	**1.7**

AEO = Annual Energy Outlook.
Btu = British thermal unit.
Note: Includes nonelectric renewables.
Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

[16] Prior to 1990, EIA did not collect data on dispersed renewable consumption and production, and the *Annual Energy Outlook 1990* (*AEO90*) was the first *AEO* to include dispersed renewables in the projections. In Table 2, the actual data for 1990 and later include dispersed renewables. Total energy consumption for 1990 and later in *AEO*s prior to the *AEO90* were adjusted to include dispersed renewables using adjustment factors derived from Energy Information Administration, *Short-Term Energy Outlook*, DOE/EIA-0202(98/2Q) (Washington, DC, April 1998).

[17] Energy Information Administration, *Annual Energy Outlook 1986*, DOE/EIA-0383(86) (Washington, DC, February 1987).

AEO86, in part due to the high fossil fuel prices projected for the publication, which was completed prior to the 1986 collapse in oil prices and published early in 1987. After *AEO86*, there was general improvement in the forecast record, as EIA's experience with lower priced energy markets expanded. It is worth noting, however, that the overall average absolute percent errors for oil price forecasts in *AEO86* were better than in the preceding *AEO*s. Price forecasts for some years in *AEO86* were also better than in some subsequent *AEO*s; for example, some of the subsequent *AEO*s projected world oil prices that were too low for the years 1989 and 1990, and the *Annual Energy Outlook 1991* (*AEO91*)[18] projected much higher prices for 1991 and 1992.

One of the aspects of modeling energy consumption that is important in the evaluation of the forecasts is the effect of regulations such as appliance and automobile efficiency standards. When such standards are incorporated, some decisions that would otherwise be made by the interaction of supply and demand factors are in fact set by fiat, helping to reduce some of the uncertainty associated with the forecasts and reducing at least one source of forecast error.

Total Petroleum Consumption

Total petroleum consumption forecasts have an average absolute percent error of 2.9 percent during the period covered in this evaluation (Table 3). The least accurate forecast year was 1988, for which the *AEO*s averaged about 0.75 million barrels per day lower than the actual consumption of 17.3 million barrels per day. For 1988, the forecasts of the world oil price were also consistently too high, as noted later, with an average absolute percent error of 80.9 percent, the highest error for any year other than 1986 and 1995. As described in the section on world oil prices, the early *AEO* world oil price projections were influenced by the notion that OPEC could curtail production sufficiently and hold prices up throughout the forecast horizon. This led to extremely high forecasts for 1995 in the early *AEO*s, like *AEO83* and *AEO84*. In addition, the forecasts of economic growth in 1988 tended to be too low in most of the *AEO* publications, which would also lead to an underestimate of demand.

AEO82, the earliest publication considered in this analysis,[19] and *AEO86* had the highest average absolute percent errors for petroleum consumption at 5.3 and 5.7 percent, respectively. Projections of petroleum consumption were underestimated for all years in *AEO86*, which was the last *AEO* completed before the oil price collapse. The projections for the years 1985 through 1987 in *AEO82* were above actual demand; however, the errors for 1988 through 1990 were much smaller and in the opposite direction.

The *AEO82* forecast for the year 1985 had the highest percent error of all the petroleum forecasts evaluated. Residential and commercial consumption was projected to be more than 0.4 million barrels per day higher in 1985 than it actually was, and consumption of petroleum for electricity generation was projected to be more than 1.8 million barrels per day higher in 1985, more than triple the actual value. Both numbers were reduced in the *Annual Energy Outlook 1983* (*AEO83*)[20] and were considerably more accurate. Although the *AEO82* total petroleum consumption projection for 1990 was equal to the historical value at 16.99 million barrels per day, the sectoral projections were not accurate. Residential and commercial demand was projected to be about 0.6 million barrels per day higher, industrial 1.0 million barrels per day higher, transportation 2.5 million barrels per day lower, and electricity generation 1.2 million barrels per day higher than actual. Between *AEO82* and *AEO83*, the role of natural gas had been reevaluated, giving it a larger role in the residential and commercial sectors and, in particular, in the electricity sector. The projections for oil demand in these sectors declined between *AEO82* and *AEO83*, and those for natural gas demand increased.

Following *AEO82*, the projections of residential and commercial oil consumption remained rather close to the actual values, although the slight downturn in 1990 was missed. A general characterization of the forecasts is a tendency to underestimate energy consumption for several years after the *Annual Energy Outlook 1984* (*AEO84*).[21] At that time, there was an assumption that residential and commercial customers would purchase the most energy-efficient technologies, an assumption that led to overly optimistic expectations of efficiency improvements. The *Annual Energy Outlook 1985* (*AEO85*)[22] shows this impact in the residential and commercial sectors.

In the early forecasts, industrial consumption of oil was overestimated, partially reflecting somewhat optimistic assumptions about the growth of energy-intensive industries but also due to an underestimation of the potential growth of natural gas in an era of high gas prices. Later projections were somewhat underestimated due to assumptions of higher efficiency gains.

Through many of the forecasts, transportation consumption was significantly underestimated. The projected world oil prices were too high; and, in reaction to

[18]Energy Information Administration, *Annual Energy Outlook 1991*, DOE/EIA-0383(91) (Washington, DC, March 1991).

[19]EIA published earlier forecasts in its *Annual Report to Congress*, which are not included in this report.

[20]Energy Information Administration, *Annual Energy Outlook 1983*, DOE/EIA-0383(83) (Washington, DC, May 1984).

[21]Energy Information Administration, *Annual Energy Outlook 1984*, DOE/EIA-0383(84) (Washington, DC, January 1985).

[22]Energy Information Administration, *Annual Energy Outlook 1985*, DOE/EIA-0383(85) (Washington, DC, February 1986).

Table 3. Total Petroleum Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Million Barrels per Day)							
AEO82	18.00	17.89	17.55	17.24	16.98	16.99								0.86
AEO83	15.82	16.13	16.37	16.50	16.56	16.63					17.37			0.40
AEO84	15.77	15.76	16.01	16.27	16.48	16.74					18.00			0.52
AEO85	15.72	15.74	15.97	16.01	16.06	16.08	16.18	16.23	16.32	16.36	16.53			0.86
AEO86		16.07	16.29	16.05	16.07	16.15	16.31	16.37	16.42	16.44	16.46	16.50	16.64	1.01
AEO87			16.52	16.66	16.96	17.06	17.29	17.56	17.73	17.76	17.72			0.32
AEO89				17.01	17.20	17.44	17.57	17.72	17.76	17.78	17.82	18.05	18.12	0.38
AEO90					17.24	17.41					18.21			0.33
AEO91						16.95	16.65	16.83	17.01	17.17	17.34	17.53	17.83	0.37
AEO92							16.74	17.07	17.37	17.59	17.80	17.86	17.99	0.21
AEO93								17.07	17.45	17.79	18.15	18.26	18.60	0.14
AEO94									17.67	17.99	18.20	18.42	18.66	0.27
AEO95										17.53	17.93	17.96	18.29	0.26
AEO96											17.78	17.88	18.10	0.32
AEO97												18.18	18.34	0.19
AEO98													18.89	0.31
Actual Value	**15.73**	**16.28**	**16.67**	**17.28**	**17.33**	**16.99**	**16.71**	**17.03**	**17.24**	**17.72**	**17.72**	**18.31**	**18.58**	
Average Absolute Error	**0.60**	**0.61**	**0.51**	**0.75**	**0.64**	**0.37**	**0.41**	**0.42**	**0.47**	**0.44**	**0.41**	**0.49**	**0.52**	**0.50**
							(Percent Error)							
AEO82	14.4	9.9	5.3	-0.2	-2.0	0.0								5.3
AEO83	0.6	-0.9	-1.8	-4.5	-4.4	-2.1					-2.0			2.3
AEO84	0.3	-3.2	-4.0	-5.8	-4.9	-1.5					1.6			3.0
AEO85	-0.1	-3.3	-4.2	-7.3	-7.3	-5.4	-3.2	-4.7	-5.3	-7.7	-6.7			5.0
AEO86		-1.3	-2.3	-7.1	-7.3	-4.9	-2.4	-3.9	-4.8	-7.2	-7.1	-9.9	-10.4	5.7
AEO87			-0.9	-3.6	-2.1	0.4	3.5	3.1	2.8	0.2	0.0			1.9
AEO89				-1.6	-0.8	2.6	5.1	4.1	3.0	0.3	0.6	-1.4	-2.5	2.2
AEO90					-0.5	2.5					2.8			1.9
AEO91						-0.2	-0.4	-1.2	-1.3	-3.1	-2.1	-4.3	-4.0	2.1
AEO92							0.2	0.2	0.8	-0.7	0.5	-2.5	-3.2	1.1
AEO93								0.2	1.2	0.4	2.4	-0.3	0.1	0.8
AEO94									2.5	1.5	2.7	0.6	0.4	1.6
AEO95										-1.1	1.2	-1.9	-1.6	1.4
AEO96											0.3	-2.3	-2.6	1.8
AEO97												-0.7	-1.3	1.0
AEO98													1.7	1.7
Average Absolute Percent Error	**3.8**	**3.7**	**3.1**	**4.3**	**3.7**	**2.2**	**2.5**	**2.5**	**2.7**	**2.5**	**2.3**	**2.7**	**2.8**	**2.9**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

the higher prices, estimated vehicle efficiency improvements were too high and vehicle miles traveled too low, leading to transportation demand forecasts that were up to 2.5 million barrels per day too low in *AEO82* and frequently up to 1 million barrels per day too low in the next several *AEO*s. These forecasts improved significantly in the *Annual Energy Outlook 1987* (*AEO87*),[23] which contained the first set of projections after the oil price collapse in 1986.

Total Natural Gas Consumption

The average absolute percent error for natural gas consumption forecasts for this period is 5.7 percent (Table 4). Projections for 1995 had the highest average absolute percent error at 9.2 percent. For 1995, all the *AEO*s underestimated consumption by anywhere from 1 to 22 percent, primarily due to high natural gas price projections. For many of the statistics presented in this paper, 1995 through 1997 show some of the highest percent errors, because these years have many of the oldest projections, which were made 10 to 12 years earlier. Particularly in the natural gas industry, there were significant changes in energy markets throughout the 1980s. Natural gas price forecasts were very high, as discussed later, and were important causes for the underestimation of consumption in many years in the analysis period, as prices were overstated considerably in comparison with the actual prices.

[23]Energy Information Administration, *Annual Energy Outlook 1987*, DOE/EIA-0383(87) (Washington, DC, March 1988).

Table 4. Total Natural Gas Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Trillion Cubic Feet)							
AEO82	15.93	15.72	15.72	16.08	16.59	17.08								1.52
AEO83	17.75	17.63	17.57	17.75	17.76	17.77					16.95			1.31
AEO84	18.22	18.07	18.33	18.61	18.73	18.76					18.75			1.06
AEO85	17.79	17.80	17.89	18.30	18.58	18.71	18.79	18.88	18.82	18.82	18.81			0.94
AEO86		16.52	16.83	17.35	17.27	17.50	17.77	17.77	17.90	18.01	18.04	18.03	18.26	1.95
AEO87			16.85	16.93	17.24	17.27	17.34	17.43	17.66	18.02	18.31			1.87
AEO89				17.75	17.95	17.94	18.08	18.10	18.34	18.68	18.94	19.17	19.55	1.62
AEO90					18.34	18.66					20.69			0.47
AEO91						18.53	19.21	19.34	19.56	19.76	20.01	20.21	20.66	0.86
AEO92							18.79	19.36	19.84	20.08	20.53	20.68	21.12	0.67
AEO93								20.27	20.17	20.54	20.97	21.54	21.83	0.37
AEO94									19.87	20.21	20.64	20.99	21.20	0.72
AEO95										20.82	20.66	20.85	21.21	0.73
AEO96											21.32	21.64	22.11	0.24
AEO97												22.15	22.75	0.47
AEO98													21.84	0.15
Actual Value	**17.28**	**16.22**	**17.21**	**18.03**	**18.80**	**18.72**	**19.04**	**19.54**	**20.28**	**20.71**	**21.58**	**21.97**	**21.99**	
Average Absolute Error	**0.82**	**1.13**	**0.73**	**0.73**	**0.99**	**0.70**	**0.77**	**1.01**	**1.26**	**1.30**	**1.99**	**1.43**	**1.11**	**1.15**
							(Percent Error)							
AEO82	-7.8	-3.1	-8.7	-10.8	-11.8	-8.8								8.5
AEO83	2.7	8.7	2.1	-1.6	-5.5	-5.1					-21.5			6.7
AEO84	5.4	11.4	6.5	3.2	-0.4	0.2					-13.1			5.8
AEO85	3.0	9.7	4.0	1.5	-1.2	-0.1	-1.3	-3.4	-7.2	-9.1	-12.8			4.8
AEO86		1.8	-2.2	-3.8	-8.1	-6.5	-6.7	-9.1	-11.7	-13.0	-16.4	-17.9	-17.0	9.5
AEO87			-2.1	-6.1	-8.3	-7.7	-8.9	-10.8	-12.9	-13.0	-15.2			9.4
AEO89				-1.6	-4.5	-4.2	-5.0	-7.4	-9.6	-9.8	-12.2	-12.7	-11.1	7.8
AEO90					-2.4	-0.3					-4.1			2.3
AEO91						-1.0	0.9	-1.0	-3.6	-4.6	-7.3	-8.0	-6.0	4.1
AEO92							-1.3	-0.9	-2.2	-3.0	-4.9	-5.9	-4.0	3.2
AEO93								3.7	-0.5	-0.8	-2.8	-2.0	-0.7	1.8
AEO94									-2.0	-2.4	-4.4	-4.5	-3.6	3.4
AEO95										0.5	-4.3	-5.1	-3.5	3.4
AEO96											-1.2	-1.5	0.5	1.1
AEO97												0.8	3.5	2.1
AEO98													-0.7	0.7
Average Absolute Percent Error	**4.7**	**7.0**	**4.3**	**4.1**	**5.3**	**3.8**	**4.0**	**5.2**	**6.2**	**6.3**	**9.2**	**6.5**	**5.1**	**5.7**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

The FUA also contributed to low estimates of gas consumption by industrial customers. In reaction to a perceived scarcity of natural gas, the FUA legislation attempted to restrict gas use by large electric utility and industrial customers. Because of the number of exemptions granted to electric utilities; however, the FUA had little impact on the forecasts of gas consumption by utilities, except in *AEO82*. The legislation did have some restraining influence on industrial gas consumption forecasts until its repeal in 1987.

With the exceptions of the projections for 1985 through 1988 made in *AEO83* through *AEO85*, natural gas consumption was generally underestimated, concurrent with high price projections. Where consumption was overestimated, the tendency to conservation and the impact of higher prices on demand were not fully captured, even though prices were generally overestimated as well. Before 1995, 1986 was the year with the highest average absolute percent error, at 7.0 percent. Except for *AEO82*, all the errors for 1986 were overestimates. Although natural gas price projections for 1986 were high, oil price projections were also high, and fuel switching from oil to gas was projected.

Among the *AEO*s, overall average absolute percent errors ranged from 1.1 to 9.5 percent, excepting the *Annual Energy Outlook 1998* (*AEO98*),[24] which included a single estimate of the most recent historical year, with a

[24]Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997).

Table 5. Total Coal Consumption: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Million Short Tons)							
AEO82	805	825	843	868	896	936								17
AEO83	807	831	848	870	899	928					1,061			29
AEO84	843	848	866	889	919	958					1,110			49
AEO85	818	833	842	853	867	891	918	943	970	989	1,008			24
AEO86		813	831	860	870	888	919	945	972	995	1,021	1,038	1,051	27
AEO87			837	837	854	879	896	912	932	954	975			15
AEO89				872	882	894	903	927	947	965	987	990	1,006	13
AEO90					884	893					984			10
AEO91						893	902	918	932	943	948	962	973	20
AEO92							905	934	919	925	934	944	953	37
AEO93								929	931	940	947	958	965	29
AEO94									920	928	933	938	943	46
AEO95										935	940	941	947	46
AEO96											937	942	954	54
AEO97												948	970	58
AEO98													1,009	18
Actual Value	**818**	**804**	**837**	**884**	**890**	**896**	**888**	**908**	**944**	**952**	**962**	**1,006**	**1,027**	
Average Absolute Error	**12**	**26**	**10**	**21**	**17**	**19**	**19**	**22**	**18**	**20**	**42**	**51**	**55**	**28**
							(Percent Error)							
AEO82	-1.6	2.6	0.7	-1.8	0.7	4.5								2.0
AEO83	-1.3	3.4	1.3	-1.6	1.0	3.6					10.3			3.2
AEO84	3.1	5.5	3.5	0.6	3.3	6.9					15.4			5.4
AEO85	0.0	3.6	0.6	-3.5	-2.6	-0.6	3.4	3.9	2.8	3.9	4.8			2.7
AEO86		1.1	-0.7	-2.7	-2.2	-0.9	3.5	4.1	3.0	4.5	6.1	3.2	2.3	2.9
AEO87			0.0	-5.3	-4.0	-1.9	0.9	0.4	-1.3	0.2	1.4			1.7
AEO89				-1.4	-0.9	-0.2	1.7	2.1	0.3	1.4	2.6	-1.6	-2.0	1.4
AEO90					-0.7	-0.3					2.3			1.1
AEO91						-0.3	1.6	1.1	-1.3	-0.9	-1.5	-4.4	-5.3	2.0
AEO92							1.9	2.9	-2.6	-2.8	-2.9	-6.2	-7.2	3.8
AEO93								2.3	-1.4	-1.3	-1.6	-4.8	-6.0	2.9
AEO94									-2.5	-2.5	-3.0	-6.8	-8.2	4.6
AEO95										-1.8	-2.3	-6.5	-7.8	4.6
AEO96											-2.6	-6.4	-7.1	5.4
AEO97												-5.8	-5.6	5.7
AEO98													-1.8	1.8
Average Absolute Percent Error	**1.5**	**3.2**	**1.1**	**2.4**	**1.9**	**2.1**	**2.2**	**2.4**	**1.9**	**2.1**	**4.4**	**5.0**	**5.3**	**3.0**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

0.7-percent error. *AEO86* and *AEO87* had the highest average absolute percent errors, mainly because of underestimates of natural gas use in the industrial sector, although projections for the residential and commercial sectors were also low in the later years. Projections in the 1980s underestimated natural gas consumption for most years, particularly the later years in the horizon, with high price forecasts contributing to the errors. Consumption forecasts improved considerably starting with the *Annual Energy Outlook 1990* (*AEO90*),[25] with average absolute percent errors of 4.1 percent or less. Natural gas price forecasts improved starting with *AEO91*, with average absolute percent errors no more than 20.1 percent.

Total Coal Consumption

The forecasts for coal consumption have been stable and displayed fairly low average errors, in part due to the good record in forecasting electricity sales, for which coal is a major fuel. The average absolute percent error for coal consumption is 3.0 percent (Table 5). As has generally been the case, forecasts for the years 1995, 1996, and 1997 tend to have the highest errors, averaging 4.4, 5.0, and 5.3 percent, respectively. There was a strong

[25]Energy Information Administration, *Annual Energy Outlook 1990*, DOE/EIA-0383(90) (Washington, DC, January 1990).

tendency to overestimate in the earlier *AEO*s, particularly *AEO84*, whose forecast for 1995 was 15.4 percent over actual consumption. Factors contributing to the overestimate included a 5.6-percent overestimate for electricity sales, an estimate of efficiency that was about 5 percent too low for coal-fired generating units, and a share for coal in generation that did not account for the eventual greater role of natural gas, particularly among nonutility electricity producers. The shares of coal and natural gas in the industrial sector were similarly affected, with high natural gas price forecasts and an overly optimistic view of the future of metallurgical coal in steelmaking being the primary factors.

Until the later *AEO*s, *AEO84* had the highest average absolute percent error for coal consumption at 5.4 percent, because of the high 1995 projection. Following an increase in natural gas prices in 1996 and 1997, coupled with declining coal prices, there was a drop in gas consumption by electricity generators and a notable surge in coal consumption by generators in 1996 and 1997, which caused some of the larger errors for those years in most *AEO*s. Consequently, the *Annual Energy Outlook 1996* (*AEO96*)[26] and *Annual Energy Outlook 1997* (*AEO97*)[27] have average absolute percent errors of 5.4 and 5.7, respectively.

Total Electricity Sales

Electricity sales have an average absolute percent error of 1.7 over the period studied (Table 6); 1996 is the year with the highest average absolute percent error of 2.5 percent. Electricity sales for all years were over-estimated in *AEO82*, and, with the exception of *AEO87*, *AEO85* through *AEO90* tended to underestimate the earlier years and overestimate the later years. In earlier *AEO*s, overestimates tended to occur because of strong growth in electricity demand in the industrial sector resulting from high projections of oil and gas prices and strong growth in consumption in the sector in general. This growth projection was moderated in later forecasts, which incorporated energy efficiency gains and structural shifts in the industrial sector to less energy-intensive industries.

In the forecasts since *AEO91*, electricity sales have been underestimated in most years, primarily as a result of optimistic estimates of efficiency improvements, coupled with continued growth in new uses for electricity that was not captured in the projections. In addition, electricity price forecasts have tended to be overstated in most years, largely due to the influence of overstated natural gas and coal prices to electricity producers, as discussed later.

In terms of the *AEO* publications, the highest average absolute percent error was that of *AEO82*, at 2.7 percent, as the models used in that *AEO* continued to anticipate electricity growth at a pace near that of economic growth, a ratio that has actually been reduced considerably in this decade. The error in electricity sales was more than halved in *AEO83*.

Energy Production

Crude Oil Production

Crude oil production forecasts have an overall average absolute percent error of 4.3 percent over the period evaluated (Table 7). The largest error for any year was 1989, with an average absolute percent error of 7.8 percent and all *AEO*s overestimating actual production for that year. Since domestic oil production is assumed to be determined by prices rather than demand, an important input to production forecasts is the world oil price, which has also been overestimated for most years, particularly in the *AEO82* through *AEO85* projections. For 1989, the first four *AEO*s had significantly high world oil price projections, leading to high production forecasts. Following *AEO85*, EIA's price forecasts were either very close to, or significantly under, the actual 1989 price, with a consequent improvement in production projections.

Each of the *AEO*s has had average absolute percent errors for crude oil production of 7.2 percent or lower, with the exception of *AEO83*, which had an average absolute percent error of 10.2 percent. *AEO83* overestimated crude oil production for all years after 1985, with particularly large errors for 1989, 1990, and 1995, the latter of which was 23.6 percent, primarily because of high price forecasts.

Following the oil price collapse of 1986, there were more underestimations than overestimates of crude oil production. As price projections have been reduced over time, the forecasts have captured the impacts of technological improvements in the oil industry, preventing the production forecasts from falling as precipitously as the price projections.

Natural Gas Production

The overall average absolute percent error for natural gas production forecasts is 4.8 percent (Table 8), lower than the 5.7-percent average absolute percent error for consumption forecasts. Unlike crude oil, most demand for natural gas is met by domestic production; thus, natural gas production tends to follow the projections for consumption. Forecasts for 1994 display the highest average absolute percent error, at 6.8 percent, followed by 1995 at 6.5 percent. The highest error for 1995, and for all the production forecasts, occurred in *AEO83*, the first *AEO* to project 1995 production. Despite a very high

[26]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996).
[27]Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (Washington, DC, December 1996).

Table 6. Total Electricity Sales: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Billion Kilowatthours)							
AEO82	2,364	2,454	2,534	2,626	2,708	2,811								68
AEO83	2,318	2,395	2,476	2,565	2,650	2,739					3,153			33
AEO84	2,321	2,376	2,461	2,551	2,637	2,738					3,182			35
AEO85	2,317	2,360	2,427	2,491	2,570	2,651	2,730	2,808	2,879	2,949	3,026			36
AEO86		2,363	2,416	2,479	2,533	2,608	2,706	2,798	2,883	2,966	3,048	3,116	3,185	52
AEO87			2,460	2,494	2,555	2,622	2,683	2,748	2,823	2,902	2,977			52
AEO89				2,556	2,619	2,689	2,760	2,835	2,917	2,994	3,072	3,156	3,236	50
AEO90					2,612	2,689					3,083			43
AEO91						2,700	2,762	2,806	2,855	2,904	2,959	3,022	3,088	32
AEO92							2,746	2,845	2,858	2,913	2,975	3,030	3,087	37
AEO93								2,803	2,840	2,893	2,946	2,998	3,052	56
AEO94									2,843	2,891	2,928	2,962	3,004	80
AEO95										2,951	2,967	2,983	3,026	68
AEO96											2,973	2,998	3,039	74
AEO97												3,075	3,115	14
AEO98													3,106	14
Actual Value	**2,324**	**2,369**	**2,457**	**2,578**	**2,647**	**2,713**	**2,762**	**2,763**	**2,861**	**2,935**	**3,013**	**3,098**	**3,120**	
Average Absolute Error	**14**	**27**	**29**	**54**	**53**	**52**	**31**	**47**	**23**	**32**	**66**	**77**	**62**	**47**
							(Percent Error)							
AEO82	1.7	3.6	3.1	1.9	2.3	3.6								2.7
AEO83	-0.3	1.1	0.8	-0.5	0.1	1.0					4.6			1.2
AEO84	-0.1	0.3	0.2	-1.0	-0.4	0.9					5.6			1.2
AEO85	-0.3	-0.4	-1.2	-3.4	-2.9	-2.3	-1.2	1.6	0.6	0.5	0.4			1.3
AEO86		-0.3	-1.7	-3.8	-4.3	-3.9	-2.0	1.3	0.8	1.1	1.2	0.6	2.1	1.9
AEO87			0.1	-3.3	-3.5	-3.4	-2.9	-0.5	-1.3	-1.1	-1.2			1.9
AEO89				-0.9	-1.1	-0.9	-0.1	2.6	2.0	2.0	2.0	1.9	3.7	1.7
AEO90					-1.3	-0.9					2.3			1.5
AEO91						-0.5	0.0	1.6	-0.2	-1.1	-1.8	-2.5	-1.0	1.1
AEO92							-0.6	3.0	-0.1	-0.7	-1.3	-2.2	-1.1	1.3
AEO93								1.4	-0.7	-1.4	-2.2	-3.2	-2.2	1.9
AEO94									-0.6	-1.5	-2.8	-4.4	-3.7	2.6
AEO95										0.5	-1.5	-3.7	-3.0	2.2
AEO96											-1.3	-3.2	-2.6	2.4
AEO97												-0.7	-0.2	0.5
AEO98													-0.4	0.4
Average Absolute Percent Error	**0.6**	**1.1**	**1.2**	**2.1**	**2.0**	**1.9**	**1.1**	**1.7**	**0.8**	**1.1**	**2.2**	**2.5**	**2.0**	**1.7**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

price forecast, the *AEO83* production projection was about 20 percent below the 1995 actual production, reflecting the low demand projection.

AEO82 underestimated gas production in all years and had an 11.7-percent average absolute percent error, followed by *AEO87* at 7.7 percent; for all the other *AEO*s the average error rate has been 6.4 percent (for *AEO86*) or less. The errors in production forecasts have resulted primarily from the low consumption forecasts, due to high price forecasts. In general, the *AEO*s have understated production, with the exception of the years prior to 1990 in *AEO84* and *AEO85*, and most of the errors have been similar to those for the forecasts of natural gas consumption.

The difficulty of predicting technological improvement in the industry—and, consequently, of predicting the amount of gas that would be available at a given price—led to the high price and low production forecasts in the earlier *AEO*s. Following the gas shortages of the late 1970s and the low resource estimates by most geologists, the conventional wisdom of the early to mid-1980s was that natural gas was a scarce resource. This perception changed as the impact of price controls that had curtailed production began to diminish. Also, beginning in the mid-1980s, a number of technological advances, such as directional drilling, 3-D seismic imaging, and slim-hole drilling, lowered the cost of gas exploration and production and expanded the estimates of the resource base. Beginning with *AEO90*, the forecasts of both production and price improved.

Table 7. Crude Oil Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Million Barrels per Day)							
AEO82	8.79	8.85	8.84	8.80	8.66	8.21								0.57
AEO83	8.67	8.71	8.66	8.72	8.80	8.63					8.11			0.75
AEO84	8.86	8.70	8.59	8.45	8.28	8.25					7.19			0.41
AEO85	8.92	8.96	9.01	8.78	8.38	8.05	7.64	7.27	6.89	6.68	6.53			0.32
AEO86		8.80	8.63	8.30	7.90	7.43	6.95	6.60	6.36	6.20	5.99	5.80	5.66	0.41
AEO87			8.31	8.18	8.00	7.63	7.34	7.09	6.86	6.64	6.54			0.11
AEO89				8.18	7.97	7.64	7.25	6.87	6.59	6.37	6.17	6.05	6.00	0.29
AEO90					7.67	7.37					6.40			0.08
AEO91						7.23	6.98	7.10	7.11	7.01	6.79	6.48	6.22	0.21
AEO92							7.37	7.17	6.99	6.89	6.68	6.45	6.28	0.10
AEO93								7.20	6.94	6.79	6.52	6.22	6.00	0.16
AEO94									6.87	6.50	6.18	5.92	5.72	0.36
AEO95										6.58	6.32	6.04	5.74	0.35
AEO96											6.54	6.33	6.16	0.13
AEO97												6.47	6.32	0.05
AEO98													6.41	0.00
Actual Value	**8.97**	**8.68**	**8.35**	**8.14**	**7.61**	**7.36**	**7.42**	**7.17**	**6.85**	**6.66**	**6.56**	**6.46**	**6.41**	
Average Absolute Error	**0.16**	**0.12**	**0.34**	**0.35**	**0.59**	**0.50**	**0.24**	**0.16**	**0.17**	**0.19**	**0.34**	**0.27**	**0.36**	**0.31**
							(Percent Error)							
AEO82	-2.0	2.0	5.9	8.1	13.8	11.6								7.2
AEO83	-3.4	0.3	3.7	7.1	15.6	17.3					23.6			10.2
AEO84	-1.2	0.2	2.9	3.8	8.8	12.2					9.6			5.5
AEO85	-0.6	3.2	7.9	7.9	10.1	9.4	3.0	1.4	0.6	0.3	-0.5			4.1
AEO86		1.4	3.4	2.0	3.8	1.0	-6.3	-8.0	-7.1	-6.9	-8.7	-10.2	-11.7	5.9
AEO87			-0.5	0.5	5.1	3.7	-1.0	-1.1	0.2	-0.3	-0.3			1.4
AEO89				0.5	4.7	3.9	-2.3	-4.2	-3.8	-4.4	-5.9	-6.3	-6.4	4.2
AEO90					0.7	0.2					-2.4			1.1
AEO91						-1.7	-5.9	-1.0	3.8	5.2	3.5	0.3	-3.0	3.1
AEO92							-0.6	0.0	2.1	3.4	1.8	-0.2	-2.0	1.5
AEO93								0.4	1.4	1.9	-0.6	-3.7	-6.4	2.4
AEO94									0.3	-2.4	-5.8	-8.4	-10.8	5.5
AEO95										-1.2	-3.7	-6.5	-10.5	5.5
AEO96											-0.3	-2.0	-3.9	2.1
AEO97												0.2	-1.4	0.8
AEO98													0.0	0.0
Average Absolute Percent Error	**1.8**	**1.4**	**4.0**	**4.3**	**7.8**	**6.8**	**3.2**	**2.3**	**2.4**	**2.9**	**5.1**	**4.2**	**5.6**	**4.3**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

Coal Production

Similar to coal consumption, coal production forecasts have an overall average absolute percent error of 3.6 percent (Table 9). Like those for natural gas, the forecasts for coal production have generally followed the consumption forecasts, with electricity sales being the dominant factor. However, an additional input is the level of coal exports, which also affects coal production significantly. Where coal production has been overestimated, a large part of the reason has been an overstating of the level of coal exports, especially for the years 1993 through 1995, as discussed below.

The year 1993 shows the highest average absolute percent error for coal production, at 9.7 percent. In 1993, there was a strike by coal miners that sharply curtailed production. Consequently, all *AEO*s produced before the strike show high forecast errors for 1993. The second highest average absolute percent error is for 1995, at 5.7 percent. The forecasts for 1995 in *AEO83* through *AEO86* range from 8.0 to 18.2 percent above the actual 1995 level, although later forecasts show errors of 5 percent or less. This reflects the overestimation of coal consumption, particularly in *AEO83* and *AEO84*, and the higher-than-realized coal export projections in *AEO83* through *AEO86*, discussed below. The forecasts for other years average much closer to the actual values, with average absolute percent errors ranging from 1.3 to 3.8 percent. The *AEO* publications display little variation in their overall average errors, with *AEO84* showing the highest average absolute percent error of 5 percent, mainly because of its very high projection for 1995.

Table 8. Natural Gas Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Trillion Cubic Feet)														
AEO82	14.74	14.26	14.33	14.89	15.39	15.88								1.98
AEO83	16.48	16.27	16.20	16.31	16.27	16.29					14.89			1.10
AEO84	17.48	17.10	17.44	17.58	17.52	17.32					16.39			0.90
AEO85	16.95	17.08	17.11	17.29	17.40	17.33	17.32	17.27	17.05	16.80	16.50			0.81
AEO86		16.30	16.27	17.15	16.68	16.90	16.97	16.87	16.93	16.86	16.62	16.40	16.33	1.17
AEO87			16.21	16.09	16.38	16.32	16.30	16.30	16.44	16.62	16.81			1.38
AEO89				16.71	16.71	16.94	17.01	16.83	17.09	17.35	17.54	17.67	17.98	0.92
AEO90					16.91	17.25					18.84			0.40
AEO91						17.40	17.48	18.11	18.22	18.15	18.22	18.39	18.82	0.33
AEO92							17.43	17.69	17.95	18.00	18.29	18.27	18.51	0.38
AEO93								18.47	18.05	18.16	18.45	18.90	19.07	0.29
AEO94									17.71	17.68	17.84	18.12	18.25	0.73
AEO95										18.28	17.98	17.92	18.21	0.69
AEO96											18.90	19.15	19.52	0.41
AEO97												19.10	19.70	0.53
AEO98													18.85	0.11
Actual Value	**16.45**	**16.06**	**16.62**	**17.10**	**17.31**	**17.81**	**17.70**	**17.84**	**18.10**	**18.82**	**18.60**	**18.79**	**18.96**	
Average Absolute Error	**0.82**	**0.86**	**0.80**	**0.73**	**0.73**	**0.96**	**0.62**	**0.73**	**0.70**	**1.28**	**1.20**	**0.75**	**0.72**	**0.87**
(Percent Error)														
AEO82	-10.4	-11.2	-13.8	-12.9	-11.1	-10.8								11.7
AEO83	0.2	1.3	-2.5	-4.6	-6.0	-8.5					-19.9			6.2
AEO84	6.3	6.5	4.9	2.8	1.2	-2.8					-11.9			5.2
AEO85	3.0	6.4	2.9	1.1	0.5	-2.7	-2.1	-3.2	-5.8	-10.7	-11.3			4.5
AEO86		1.5	-2.1	0.3	-3.6	-5.1	-4.1	-5.4	-6.5	-10.4	-10.6	-12.7	-13.9	6.4
AEO87			-2.5	-5.9	-5.4	-8.4	-7.9	-8.6	-9.2	-11.7	-9.6			7.7
AEO89				-2.3	-3.5	-4.9	-3.9	-5.7	-5.6	-7.8	-5.7	-6.0	-5.2	5.0
AEO90					-2.3	-3.1					1.3			2.2
AEO91						-2.3	-1.2	1.5	0.7	-3.6	-2.0	-2.1	-0.7	1.8
AEO92							-1.5	-0.8	-0.8	-4.4	-1.7	-2.8	-2.4	2.1
AEO93								3.5	-0.3	-3.5	-0.8	0.6	0.6	1.5
AEO94									-2.2	-6.1	-4.1	-3.6	-3.7	3.9
AEO95										-2.9	-3.3	-4.6	-4.0	3.7
AEO96											1.6	1.9	3.0	2.2
AEO97												1.6	3.9	2.8
AEO98													-0.6	0.6
Average Absolute Percent Error	**5.0**	**5.4**	**4.8**	**4.3**	**4.2**	**5.4**	**3.5**	**4.1**	**3.9**	**6.8**	**6.5**	**4.0**	**3.8**	**4.8**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

Energy Imports and Exports

While the United States is a major importer of petroleum, it also imports natural gas, although in much smaller quantities. Coal is the only fuel for which the United States is a net exporter.

Net Petroleum Imports

Because domestic production of petroleum is insufficient to meet demand, imports make up the difference between demand and supply.[28] The average absolute percent error for net petroleum imports over the period studied was 9.5 percent (Table 10). The forecast year with the highest average absolute percent error proved to be 1985, for which the *AEO*s averaged a 28.1-percent error; subsequent years showed considerable improvement. In general, there was a tendency to underestimate imports for the mid-1980s, because of underestimates of consumption and overestimates of production. Except for *AEO83* and *AEO85*, this tendency was generally reversed in projections of the 1990s, with significant overestimates of net petroleum imports for many years in *AEO84* through the *Annual Energy Outlook 1995* (*AEO95*).[29] Although in some *AEO*s this corresponded to overestimates of consumption and/or underestimates

[28]Stocks may also contribute but are assumed to be stable over the long term and have not been specifically projected in the *AEO* forecasts.

[29]Energy Information Administration, *Annual Energy Outlook 1995*, DOE/EIA-0383(95) (Washington, DC, January 1995).

Table 9. Coal Production: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Million Short Tons)							
AEO82	914	939	963	995	1,031	1,080								45
AEO83	900	926	947	974	1,010	1,045					1,191			44
AEO84	899	921	948	974	1,010	1,057					1,221			49
AEO85	886	909	930	940	958	985	1,015	1,041	1,072	1,094	1,116			40
AEO86		890	920	954	962	983	1,017	1,044	1,073	1,097	1,126	1,142	1,156	47
AEO87			917	914	932	962	978	996	1,020	1,043	1,068			33
AEO89				941	946	977	990	1,018	1,039	1,058	1,082	1,084	1,107	33
AEO90					973	987					1,085			34
AEO91						1,035	1,002	1,016	1,031	1,043	1,054	1,065	1,079	20
AEO92							1,004	1,040	1,019	1,034	1,052	1,064	1,074	23
AEO93								1,039	1,043	1,054	1,065	1,076	1,086	34
AEO94									999	1,021	1,041	1,051	1,056	24
AEO95										1,006	1,010	1,011	1,016	44
AEO96											1,037	1,044	1,041	24
AEO97												1,028	1,052	37
AEO98													1,088	1
Actual Value	**884**	**890**	**919**	**950**	**981**	**1,029**	**996**	**998**	**945**	**1,034**	**1,033**	**1,064**	**1,089**	
Average Absolute Error	**16**	**27**	**19**	**22**	**30**	**39**	**13**	**30**	**92**	**25**	**59**	**26**	**31**	**36**
							(Percent Error)							
AEO82	3.4	5.5	4.8	4.7	5.1	5.0								4.7
AEO83	1.8	4.0	3.0	2.5	3.0	1.6					15.3			4.5
AEO84	1.7	3.5	3.2	2.5	3.0	2.7					18.2			5.0
AEO85	0.2	2.1	1.2	-1.1	-2.3	-4.3	1.9	4.3	13.4	5.8	8.0			4.1
AEO86		0.0	0.1	0.4	-1.9	-4.5	2.1	4.6	13.5	6.1	9.0	7.3	6.2	4.6
AEO87			-0.2	-3.8	-5.0	-6.5	-1.8	-0.2	7.9	0.9	3.4			3.3
AEO89				-0.9	-3.6	-5.1	-0.6	2.0	9.9	2.3	4.7	1.9	1.7	3.3
AEO90					-0.8	-4.1					5.0			3.3
AEO91						0.6	0.6	1.8	9.1	0.9	2.0	0.1	-0.9	2.0
AEO92							0.8	4.2	7.8	0.0	1.8	0.0	-1.4	2.3
AEO93								4.1	10.4	1.9	3.1	1.1	-0.3	3.5
AEO94									5.7	-1.3	0.8	-1.2	-3.0	2.4
AEO95										-2.7	-2.2	-5.0	-6.7	4.2
AEO96											0.4	-1.9	-4.4	2.2
AEO97												-3.4	-3.4	3.4
AEO98													-0.1	0.1
Average Absolute Percent Error	**1.8**	**3.0**	**2.1**	**2.3**	**3.1**	**3.8**	**1.3**	**3.0**	**9.7**	**2.4**	**5.7**	**2.4**	**2.8**	**3.6**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

of production, it was also exacerbated by the contribution of inaccurate forecasts for other sources of supply, such as natural gas liquids and processing gain, the treatment of stocks, and assumptions about the pace of acquisition of crude oil for the Strategic Petroleum Reserve.

By publication, the *AEO*s for 1982 through 1985, 1987, 1989, and 1994 proved to have the highest average absolute percent errors for forecasts of net petroleum imports. *AEO82* strongly overestimated imports for 1985 through 1987; however, its forecasts for the subsequent years were markedly better. Because high estimates of oil prices led to high production forecasts, *AEO83*, *AEO84*, and *AEO85* strongly underestimated imports in many years, as did *AEO86* for the late 1980s. Later reports tended to overestimate imports due to underestimates of production.

Net Natural Gas Imports

Net natural gas imports play a small, but important, supplementary role in meeting natural gas demand. The overall average absolute percent error for the period covered in this study is 16.7 percent, with the largest average absolute percent error for the year 1986 at 49.2 percent (Table 11). All the forecasts for 1986 were overstated, with errors as high as 72.7 percent (*AEO82*). There was a substantial oil price collapse in 1986, and petroleum imports displaced other energy sources, such as Canadian gas, for much of the Nation's consumption needs, especially in the industrial and electricity generation sectors. Forecasts for 1987 were overstated in

Table 10. Net Petroleum Imports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Million Barrels per Day)							
AEO82	7.58	7.45	7.12	6.82	6.66	7.09								1.23
AEO83	5.15	5.44	5.73	5.79	5.72	5.95					6.96			0.78
AEO84	4.85	5.11	5.53	5.95	6.31	6.59					8.65			0.59
AEO85	4.17	4.38	4.73	4.93	5.36	5.72	6.23	6.66	7.14	7.39	7.74			0.84
AEO86		5.15	5.38	5.46	5.92	6.46	7.09	7.50	7.78	7.96	8.20	8.47	8.74	0.47
AEO87			5.81	6.04	6.81	7.28	7.82	8.34	8.71	8.94	8.98			0.76
AEO89				6.28	6.84	7.49	7.96	8.53	8.83	9.04	9.28	9.60	9.64	0.93
AEO90					7.20	7.61					9.13			0.56
AEO91						7.28	7.25	7.34	7.48	7.72	8.10	8.57	9.09	0.26
AEO92							6.86	7.42	7.88	8.16	8.55	8.80	9.06	0.31
AEO93								7.25	8.01	8.49	9.06	9.38	9.92	0.70
AEO94									8.04	8.77	9.21	9.60	10.02	0.94
AEO95										8.09	8.65	8.99	9.56	0.49
AEO96											8.25	8.51	8.82	0.15
AEO97												8.49	8.89	0.01
AEO98													9.05	0.15
Actual Value	**4.29**	**5.44**	**5.91**	**6.59**	**7.20**	**7.16**	**6.63**	**6.94**	**7.62**	**8.05**	**7.89**	**8.50**	**8.90**	
Average Absolute Error	**1.21**	**0.74**	**0.60**	**0.76**	**0.85**	**0.56**	**0.71**	**0.72**	**0.52**	**0.47**	**0.80**	**0.44**	**0.43**	**0.65**
							(Percent Error)							
AEO82	76.7	36.9	20.5	3.5	-7.5	-1.0								24.3
AEO83	20.0	0.0	-3.0	-12.1	-20.6	-16.9					-11.8			12.1
AEO84	13.1	-6.1	-6.4	-9.7	-12.4	-8.0					9.6			9.3
AEO85	-2.8	-19.5	-20.0	-25.2	-25.6	-20.1	-6.0	-4.0	-6.3	-8.2	-1.9			12.7
AEO86		-5.3	-9.0	-17.1	-17.8	-9.8	6.9	8.1	2.1	-1.1	3.9	-0.4	-1.8	6.9
AEO87			-1.7	-8.3	-5.4	1.7	17.9	20.2	14.3	11.1	13.8			10.5
AEO89				-4.7	-5.0	4.6	20.1	22.9	15.9	12.3	17.6	12.9	8.3	12.4
AEO90					0.0	6.3					15.7			7.3
AEO91						1.7	9.4	5.8	-1.8	-4.1	2.7	0.8	2.1	3.5
AEO92							3.5	6.9	3.4	1.4	8.4	3.5	1.8	4.1
AEO93								4.5	5.1	5.5	14.8	10.4	11.5	8.6
AEO94									5.5	8.9	16.7	12.9	12.6	11.3
AEO95										0.5	9.6	5.8	7.4	5.8
AEO96											4.6	0.1	-0.9	1.9
AEO97												-0.1	-0.1	0.1
AEO98													1.7	1.7
Average Absolute Percent Error	**28.1**	**13.6**	**10.1**	**11.5**	**11.8**	**7.8**	**10.6**	**10.3**	**6.8**	**5.9**	**10.1**	**5.2**	**4.8**	**9.5**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

the first four *AEO*s, but *AEO86* and *AEO87* reversed the pattern with underestimates. *AEO85* also showed high overestimates through 1992 and underestimates for later years. Most *AEO*s tended to underestimate imports, with errors as high as 54.2 percent for 1995 in *AEO83*.

The major determining factors of natural gas imports have been the economics of natural gas trade with Canada, the assumptions of pipeline capacity from Canada, the assessment of liquefied natural gas imports from Algeria, and prospects for trade with Mexico and Japan. The tendency was for net gas imports to be overstated for the first four *AEO*s, except for the 1989, 1990, and 1993 through 1995 forecasts. Since the *AEO86* forecast, there has been a greater tendency to underestimate gas imports. Since the *Annual Energy Outlook 1993* (*AEO93*),[30] the projections have been much closer to the actual values, with average absolute percent errors of 5.6 percent or less, although the *AEO98* projection for 1997 reflects an historical update.

Net Coal Exports

The absolute percent errors in projections for net coal exports have averaged 22.8 percent over the period of this study (Table 12). The forecast year 1994 had the highest average absolute percent error at 48.1 percent, followed by 1993 at 39.9 percent. All the *AEO*s except

[30]Energy Information Administration, *Annual Energy Outlook 1993*, DOE/EIA-0383(93) (Washington, DC, January 1993).

Table 11. Net Natural Gas Imports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Trillion Cubic Feet)							
AEO82	1.19	1.19	1.19	1.19	1.19	1.19								0.24
AEO83	1.08	1.16	1.23	1.23	1.23	1.23					1.23			0.38
AEO84	0.99	1.05	1.16	1.27	1.43	1.57					2.11			0.23
AEO85	0.94	1.00	1.19	1.45	1.58	1.86	1.94	2.06	2.17	2.32	2.44			0.22
AEO86		0.74	0.88	0.62	1.03	1.05	1.27	1.39	1.47	1.66	1.79	1.96	2.17	0.51
AEO87			0.84	0.89	1.07	1.16	1.26	1.36	1.46	1.65	1.75			0.49
AEO89				1.15	1.32	1.44	1.52	1.61	1.70	1.79	1.87	1.98	2.06	0.41
AEO90					1.26	1.43					2.07			0.22
AEO91						1.36	1.53	1.70	1.82	2.11	2.30	2.33	2.36	0.31
AEO92							1.48	1.62	1.88	2.08	2.25	2.41	2.56	0.32
AEO93								1.79	2.08	2.35	2.49	2.61	2.74	0.14
AEO94									2.02	2.40	2.66	2.74	2.81	0.07
AEO95										2.46	2.54	2.80	2.87	0.05
AEO96											2.56	2.75	2.85	0.06
AEO97												2.82	2.96	0.09
AEO98													2.95	0.13
Actual Value	**0.89**	**0.69**	**0.94**	**1.22**	**1.28**	**1.45**	**1.64**	**1.92**	**2.21**	**2.46**	**2.69**	**2.78**	**2.82**	
Average Absolute Error	**0.16**	**0.34**	**0.20**	**0.19**	**0.14**	**0.20**	**0.24**	**0.31**	**0.39**	**0.37**	**0.53**	**0.30**	**0.26**	**0.30**
							(Percent Error)							
AEO82	33.1	72.7	26.7	-2.5	-7.0	-17.7								26.6
AEO83	20.8	68.4	31.0	0.8	-3.9	-14.9					-54.2			27.7
AEO84	10.7	52.4	23.5	4.1	11.7	8.6					-21.5			18.9
AEO85	5.1	45.1	26.7	18.9	23.4	28.6	18.0	7.2	-1.8	-5.8	-9.2			17.3
AEO86		7.4	-6.3	-49.2	-19.5	-27.4	-22.7	-27.6	-33.5	-32.6	-33.4	-29.5	-23.0	26.0
AEO87			-10.5	-27.0	-16.4	-19.8	-23.4	-29.2	-33.9	-33.0	-34.9			25.3
AEO89				-5.7	3.1	-0.4	-7.5	-16.2	-23.1	-27.3	-30.4	-28.8	-27.0	17.0
AEO90					-1.6	-1.1					-23.0			8.5
AEO91						-5.9	-6.9	-11.5	-17.6	-14.3	-14.4	-16.2	-16.3	12.9
AEO92							-10.0	-15.7	-14.9	-15.5	-16.3	-13.3	-9.2	13.6
AEO93								-6.8	-5.9	-4.5	-7.3	-6.1	-2.8	5.6
AEO94									-8.6	-2.5	-1.0	-1.4	-0.4	2.8
AEO95										-0.1	-5.5	0.7	1.8	2.0
AEO96											-4.7	-1.1	1.1	2.3
AEO97												1.4	5.0	3.2
AEO98													4.6	4.6
Average Absolute Percent Error	**17.4**	**49.2**	**20.8**	**15.5**	**10.8**	**13.8**	**14.8**	**16.3**	**17.4**	**15.1**	**19.7**	**11.0**	**9.1**	**16.7**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

AEO95 overstated 1994 coal exports by anywhere from about 30 to 77 percent. For *AEO84* through *AEO94*, coal exports were generally underestimated through 1992 and overestimated in later years. *AEO95* and *AEO96* underestimated exports by a range of 8 to 19 percent.

AEO82 overestimated future coal exports with an average absolute percent error of 37.5 percent, due largely to the assumption that U.S. coal exports would garner an ever-increasing share of world coal trade, which was also expected to grow in reaction to high world oil prices. *AEO83*, in contrast, had a much more realistic view of future coal exports and, with the exception of 1995, had much smaller errors. *AEO83*, *AEO96*, *AEO97*, and *AEO98* were the closest of all the *AEO*s with respect to projected coal exports. Projections for 1993 through 1997 in *AEO91* through *AEO94* were far too high, in part because of the 1993 coal miners' strike that reduced this country's competitive position in world coal markets. In addition, world coal trade has not grown as much as previously assumed, because European consumers have turned increasingly to natural gas for industry and power generation, and environmental concerns have led some countries to reduce coal consumption as a means of reducing carbon emissions. *AEO95* and *AEO96* appear to be overcompensating for this trend. *AEO98* reflects historical data for 1997.

Table 12. Net Coal Exports: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Million Short Tons)														
AEO82	109	114	120	127	135	144								34
AEO83	83	86	90	94	99	105					116			9
AEO84	72	74	77	81	86	91					106			13
AEO85	83	83	83	84	85	87	89	92	95	98	102			14
AEO86		87	87	88	89	91	92	94	96	98	100	101	102	15
AEO87			76	72	73	76	77	79	82	83	86			18
AEO89				84	80	82	83	85	87	88	90	93	97	17
AEO90					95	92					99			11
AEO91						105	96	96	97	100	104	100	104	19
AEO92							98	99	103	109	116	117	120	29
AEO93								108	111	113	117	118	120	36
AEO94									79	93	108	110	113	26
AEO95										57	66	69	70	11
AEO96											71	76	77	6
AEO97												82	84	5
AEO98													80	4
Actual Value	**91**	**83**	**78**	**93**	**98**	**103**	**106**	**99**	**67**	**64**	**81**	**83**	**76**	
Average Absolute Error	**13**	**9**	**12**	**13**	**15**	**16**	**17**	**8**	**27**	**31**	**21**	**18**	**22**	**18**
(Percent Error)														
AEO82	19.8	37.3	53.8	36.6	37.8	39.8								37.5
AEO83	-8.8	3.6	15.4	1.1	1.0	1.9					43.2			10.7
AEO84	-20.9	-10.8	-1.3	-12.9	-12.2	-11.7					30.9			14.4
AEO85	-8.8	0.0	6.4	-9.7	-13.3	-15.5	-16.0	-7.1	41.8	53.1	25.9			18.0
AEO86		4.8	11.5	-5.4	-9.2	-11.7	-13.2	-5.1	43.3	53.1	23.5	21.7	34.2	19.7
AEO87			-2.6	-22.6	-25.5	-26.2	-27.4	-20.2	22.4	29.7	6.2			20.3
AEO89				-9.7	-18.4	-20.4	-21.7	-14.1	29.9	37.5	11.1	12.0	27.6	20.2
AEO90					-3.1	-10.7					22.2			12.0
AEO91						1.9	-9.4	-3.0	44.8	56.3	28.4	20.5	36.8	25.1
AEO92							-7.5	0.0	53.7	70.3	43.2	41.0	57.9	39.1
AEO93								9.1	65.7	76.6	44.4	42.2	57.9	49.3
AEO94									17.9	45.3	33.3	32.5	48.7	35.6
AEO95										-10.9	-18.5	-16.9	-7.9	13.6
AEO96											-12.3	-8.4	1.3	7.4
AEO97												-1.2	10.5	5.9
AEO98													5.3	5.3
Average Absolute Percent Error	**14.6**	**11.3**	**15.2**	**14.0**	**15.1**	**15.5**	**15.9**	**8.4**	**39.9**	**48.1**	**26.4**	**21.8**	**28.8**	**22.8**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

Energy Prices and Economic Growth[31]

World Oil Prices

World oil prices have the second highest average absolute percent errors of all the variables evaluated in this paper, with natural gas prices at the wellhead having the highest. Overall, the average absolute percent error for world oil price forecasts has been 51.3 percent (Table 13). However, the earlier *AEO*s had a much higher average absolute percent error, and the publications after *AEO86* show considerable improvement, with the exception of *AEO91*, which was affected by the Iraqi invasion of Kuwait. *AEO91*, prepared during the short-term escalation of oil prices caused by the invasion, projected continually rising prices. In fact, oil prices declined over each of the next 4 years. Similarly, the year with the highest average absolute percent error was 1995, followed closely by 1986, with very high percentage errors in the earliest *AEO*s only partially offset by smaller errors in the more recent forecasts. In nominal terms, the first forecast for 1995, from *AEO83,* was nearly $75 per barrel, compared with the actual 1995 price of $17.14 per barrel.

For many of the variables examined in this paper, the highest average errors are seen for the year 1995. As

[31]Forecasts of energy prices and the gross national or gross domestic product (GDP) have been converted to nominal terms by using the historical gross domestic product deflators.

Table 13. World Oil Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Nominal Dollars per Barrel)														
AEO82	28.49	32.47	37.38	41.90	45.66	49.02								20.23
AEO83	28.44	28.18	30.67	36.07	41.41	46.93					74.32			22.19
AEO84	28.92	28.67	29.56	31.76	34.27	37.00					56.71			16.60
AEO85	27.00	25.70	24.38	25.26	28.60	32.23	34.75	36.99	37.95	40.14	41.17			14.09
AEO86		14.57	15.89	17.28	18.91	20.72	22.20	24.74	28.25	32.02	35.52	38.48	41.36	8.75
AEO87			18.11	17.41	19.01	20.06	20.97	21.54	23.17	25.71	29.00			4.47
AEO89				14.70	15.00	16.31	17.52	18.47	20.38	23.03	25.74	28.67	31.75	5.17
AEO90					17.70	17.53					24.47			3.98
AEO91						22.00	24.95	25.64	26.31	26.90	27.59	28.13	28.85	7.96
AEO92							19.13	20.19	20.72	22.19	23.91	25.55	27.52	4.90
AEO93								18.90	20.09	20.92	22.01	22.89	23.93	3.75
AEO94									17.12	17.24	18.28	19.37	20.57	1.42
AEO95										15.23	17.21	18.07	19.13	0.87
AEO96											17.24	17.76	18.63	1.01
AEO97												19.90	19.38	0.77
AEO98													18.62	0.04
Actual Value	**26.99**	**14.00**	**18.13**	**14.56**	**18.08**	**21.76**	**18.70**	**18.20**	**16.14**	**15.51**	**17.14**	**20.64**	**18.58**	
Average Absolute Error	**1.22**	**11.92**	**8.62**	**11.78**	**10.36**	**10.09**	**4.95**	**5.58**	**8.11**	**9.37**	**14.64**	**5.33**	**6.39**	**8.84**
(Percent Error)														
AEO82	5.5	131.9	106.2	187.7	152.5	125.3								118.2
AEO83	5.4	101.3	69.2	147.7	129.1	115.7					333.6			128.8
AEO84	7.2	104.8	63.1	118.2	89.6	70.0					230.8			97.7
AEO85	0.0	83.6	34.5	73.5	58.2	48.1	85.8	103.2	135.1	158.8	140.2			83.7
AEO86		4.1	-12.4	18.7	4.6	-4.8	18.7	35.9	75.0	106.4	107.3	86.4	122.6	49.7
AEO87			-0.1	19.6	5.1	-7.8	12.1	18.4	43.6	65.8	69.2			26.9
AEO89				1.0	-17.0	-25.1	-6.3	1.5	26.3	48.5	50.2	38.9	70.9	28.6
AEO90					-2.1	-19.4					42.8			21.4
AEO91						1.1	33.4	40.9	63.0	73.4	61.0	36.3	55.3	45.5
AEO92							2.3	10.9	28.4	43.1	39.5	23.8	48.1	28.0
AEO93								3.8	24.5	34.9	28.4	10.9	28.8	21.9
AEO94									6.1	11.1	6.7	-6.1	10.7	8.1
AEO95										-1.8	0.4	-12.5	3.0	4.4
AEO96											0.6	-14.0	0.3	4.9
AEO97												-3.6	4.3	4.0
AEO98													0.2	0.2
Average Absolute Percent Error	**4.5**	**85.1**	**47.6**	**80.9**	**57.3**	**46.4**	**26.5**	**30.7**	**50.2**	**60.4**	**85.4**	**25.8**	**34.4**	**51.3**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

mentioned before, the 1995 projections include those made furthest in the past—up to 12 years earlier. In addition, projections for 1991 through 1994 are not available from the earliest publications, so that 1995 appears to be more of an outlier.

Although the forecasts of world oil prices appearing in the earlier *AEO*s were almost uniformly too high, from *AEO86* on there were several instances of forecasts that were too low. These included the 1987 and 1990 forecasts appearing in *AEO86* and *AEO87*, the forecasts for 1989 through 1991 appearing in the *Annual Energy Outlook 1989* (*AEO89*)[32] and *AEO90*, and the most recent forecasts for 1996. Clearly, following the oil price collapse of 1986, EIA's forecasts were significantly reduced; as a consequence, the projections for 1990 tended to be too low, in part because of the rise in oil prices beginning in August 1990 associated with Iraq's invasion of Kuwait. Even with the lower price forecasts, 1995 had high percentage errors until *AEO94*, as most *AEO*s continued to show rising prices in response to perceived rising world oil demand.

The early *AEO* projections were strongly influenced by the notion that OPEC would continue to hold a large measure of power in world oil markets. Conventional wisdom in the early projections assumed that OPEC would be able to curtail production sufficiently to hold prices up, and that the cartel's members would continue their cooperation throughout the forecast horizon. Even

[32]Energy Information Administration, *Annual Energy Outlook 1989*, DOE/EIA-0383(89) (Washington, DC, January 1989).

as it became clear that OPEC's cohesiveness was not permanent, EIA continued to assume that oil prices would rise with increasing demand, although at a much slower rate of growth than in the 1970s. Increasing investment in areas outside OPEC and technological advances in oil exploration and production have contributed to the growth in oil reserves and production capacity of non-OPEC producers. These trends, combined with competition from natural gas and energy conservation, have kept prices lower than expected in the earlier forecasts.

Natural Gas Prices

Natural gas prices at the wellhead have had the highest average absolute percentage forecast errors in the *AEO*s, with an overall average error of 72.1 percent (Table 14). Occasionally, near-term gas prices have been underestimated, but most of the projections were overestimates. Similar to the forecasts for world oil prices, those for natural gas prices were highest in the earlier *AEO*s, when the projections for all prices were influenced by the assumption that market forces would tend to increase demand for, and therefore prices of, natural gas and coal in response to higher world oil prices.

The year 1995 had the highest average absolute percent error; with the exception of *AEO96*, which was essentially estimating the recent historical year for 1995, the smallest error for 1995 was 28.6 percent in *AEO95*. The year with the lowest average absolute percent error was 1985, with an average absolute error for four *AEO*s of 23.3 percent, even including the 65.2-percent error in the *AEO82* projection for 1985. Despite the large errors,

Table 14. Natural Gas Wellhead Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Nominal Dollars per Thousand Cubic Feet)														
AEO82	4.15	5.10	6.02	6.55	6.83	7.11								4.09
AEO83	2.87	2.98	3.25	3.60	4.10	4.64					9.32			2.57
AEO84	2.76	2.82	3.07	3.39	3.81	4.34					7.16			2.08
AEO85	2.60	2.59	2.61	2.62	2.84	3.20	3.62	4.07	4.51	4.99	5.53			1.74
AEO86		1.73	1.96	2.29	2.55	2.82	3.14	3.64	4.12	4.65	5.25	5.83	6.41	1.89
AEO87			1.83	1.96	2.12	2.30	2.49	2.70	2.98	3.28	3.69			0.86
AEO89				1.62	1.71	1.90	2.10	2.49	2.86	3.18	3.50	4.10	4.39	0.95
AEO90					1.78	1.89					2.70			0.47
AEO91						1.77	1.91	2.12	2.29	2.38	2.44	2.48	2.58	0.36
AEO92							1.69	1.86	2.04	2.14	2.32	2.44	2.63	0.25
AEO93								1.85	1.92	2.06	2.26	2.36	2.49	0.23
AEO94									1.99	2.13	2.27	2.40	2.58	0.29
AEO95										1.89	1.99	1.94	2.05	0.27
AEO96											1.64	1.75	1.87	0.36
AEO97												2.02	1.82	0.38
AEO98													2.31	0.11
Actual Value	**2.51**	**1.94**	**1.67**	**1.69**	**1.69**	**1.71**	**1.64**	**1.74**	**2.04**	**1.85**	**1.55**	**2.17**	**2.42**	
Average Absolute Error	**0.58**	**1.19**	**1.45**	**1.48**	**1.53**	**1.62**	**0.85**	**0.93**	**0.84**	**1.12**	**2.30**	**0.82**	**0.82**	**1.27**
(Percent Error)														
AEO82	65.2	163.1	260.5	287.8	304.0	315.8								232.7
AEO83	14.5	53.5	94.7	113.3	142.5	171.1					501.1			155.8
AEO84	9.9	45.6	83.6	100.7	125.2	153.9					361.9			125.8
AEO85	3.6	33.5	56.1	55.3	67.9	87.1	121.0	133.8	121.3	169.8	256.8			100.6
AEO86		-10.8	17.3	35.3	50.8	65.0	91.4	108.9	102.2	151.2	238.5	168.4	164.7	100.4
AEO87			9.6	15.9	25.2	34.4	52.1	54.9	45.9	77.4	138.1			50.4
AEO89				-4.1	1.1	11.3	28.2	42.8	40.2	71.9	125.8	89.1	81.4	49.6
AEO90					5.3	10.5					74.1			30.0
AEO91						3.5	16.6	21.6	12.3	28.4	57.2	14.5	6.8	20.1
AEO92							3.3	6.8	-0.1	15.7	49.8	12.3	8.8	13.8
AEO93								6.3	-5.9	11.3	45.5	8.6	2.7	13.4
AEO94									-2.4	15.1	46.5	10.7	6.5	16.2
AEO95										2.2	28.6	-10.8	-15.3	14.2
AEO96											5.9	-19.5	-22.9	16.1
AEO97												-7.0	-24.8	15.9
AEO98													-4.7	4.7
Average Absolute Percent Error	**23.3**	**61.3**	**87.0**	**87.5**	**90.2**	**94.7**	**52.1**	**53.6**	**41.3**	**60.3**	**148.4**	**37.9**	**33.9**	**72.1**

AEO = *Annual Energy Outlook*.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

the forecasts in each subsequent *AEO* have tended to show considerable improvement, as the downward trend in gas prices has been better captured from one *AEO* to another.

Nevertheless, each *AEO* has tended to predict rising prices over time, either because of the assumption in the earlier *AEO*s that long-term, high-priced contracts would continue or because the depletion effects associated with rising consumption were expected to overcome technological improvement in the more recent forecasts. In summary, three factors have had significant impacts on the projections:

- In the earlier *AEO*s, it was assumed that natural gas contracts whose provisions were governed by the Natural Gas Policy Act of 1978 would not be abrogated and that the prices that prevailed under those contracts would essentially set the market price over time. In fact, when oil prices fell in 1986, many of those contracts were abrogated, and the price of natural gas fell, although not as much as the price of oil.

- Estimates of the recoverable resource base rose and estimates of exploration and production costs fell over time, in contrast to the assumptions in the earlier forecasts. Because the models use this information as an input, higher assumed levels of recoverable resources and lower assumed costs would have resulted in forecasts characterized by more gas available for production at lower prices. More recent *AEO*s have allowed for increases in the resource base and decreases in costs due to technology improvements.

- Consistent with the assumption of existing regulations, the earlier *AEO*s did not assume that there would be additional competition in the transmission and distribution sectors of the market; however, from 1985 on, FERC moved to open access to the interstate pipeline transmission system, lowering end-use prices and stimulating additional price competition at the wellhead as well.

Thus, although the forecasts have improved with additional information, they have continued to be affected by the impacts of wellhead price deregulation and the changing competitive structure of the industry and by overestimates of the impacts of reserve depletion relative to technology improvements.

It is worth noting that approximately one-fourth of the domestic production of natural gas is as a coproduct of the crude oil extraction process, which means that, as crude oil production rises with higher oil prices, there may be a depressing effect on the wellhead price of gas. This effect has added to the complexity of forecasting natural gas prices.

Coal Prices to Electric Utilities

Although they are better than those for oil and gas prices, the *AEO* forecasts of coal prices to electric utilities still show an average absolute percent error of 35.3 percent over the period studied (Table 15). All forecasts were overstated. The forecasts for 1995 had the highest average absolute percent error of 57.5 percent. There was, however, significant improvement in the 1995 forecast over time, with the error improving from 137.9 percent in *AEO83* to 10.6 percent in *AEO95* (excluding *AEO96*, which provided an estimate for the historical year 1995 based on partial year data). Across forecast years, the further out the forecast, the higher the error, with the lowest average absolute percent error shown for the year 1985 at 13.3 percent.

The early *AEO*s—*AEO82* through *AEO86*—tended to have the highest average absolute percent errors, exacerbated by their forecasts for 1995. There was steady improvement in the *AEO*s through *AEO90*, which had an average absolute percent error of 16.8. After *AEO90*, overestimates for 1995 through 1997 adversely affected the overall average errors for a number of the subsequent *AEO*s.

The major factors in the high forecasts of coal prices were assumptions about depletion effects, productivity improvements, capacity utilization, transportation, and the impacts of CAAA90. Depletion was assumed to overcome productivity improvements in the long run; however, the onset of such new technology as longwall mines and the growth of surface mining in the West have led to continuing productivity improvements. Similarly, with high world oil price forecasts, the impacts of excess capacity and competition among existing mines were not seen to be as important as they in fact became. In addition, high world oil prices were assumed to affect both the production process and the costs of transportation. In fact, the collapse of oil prices in 1986 reduced the impact on both, and the increasing competitiveness of rail transportation has held transportation costs below expectations. Finally, it was assumed that high prices would follow the enactment of CAAA90 as the demand for low-sulfur coal increased. Price increases did not materialize, however, as productivity increases and transportation cost reductions made increased production from western mines possible at lower-than-anticipated prices.

Average Electricity Prices

Average electricity prices showed the best forecasting record among the prices examined here, with an average absolute percent error of 11.0 percent (Table 16). As with all the price forecasts, because of the projections made 12 years earlier, the year with the highest average absolute percent error was 1995, which had an average error of 15.5 percent. Except for the two near-term forecasts of 1985 for *AEO82* and 1989 for *AEO90*, price forecasts have

Table 15. Coal Prices to Electric Utilities: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Nominal Dollars per Million Btu)														
AEO82	1.95	2.02	2.10	2.20	2.32	2.48								0.66
AEO83	1.95	2.02	2.10	2.19	2.31	2.43					3.14			0.82
AEO84	1.89	1.96	2.04	2.13	2.25	2.37					2.91			0.73
AEO85	1.68	1.75	1.82	1.89	1.98	2.09	2.18	2.27	2.36	2.42	2.51			0.63
AEO86		1.61	1.68	1.75	1.84	1.94	2.04	2.13	2.23	2.33	2.43	2.50	2.58	0.68
AEO87			1.52	1.56	1.66	1.76	1.85	1.94	2.04	2.12	2.21			0.43
AEO89				1.50	1.52	1.67	1.75	1.81	1.88	1.95	2.01	2.06	2.14	0.44
AEO90					1.46	1.53					1.91			0.22
AEO91						1.51	1.59	1.67	1.76	1.85	1.91	1.97	2.04	0.42
AEO92							1.55	1.62	1.67	1.75	1.83	1.91	1.95	0.40
AEO93								1.49	1.53	1.58	1.67	1.71	1.79	0.29
AEO94									1.51	1.55	1.65	1.72	1.78	0.32
AEO95										1.42	1.46	1.48	1.54	0.16
AEO96											1.35	1.35	1.37	0.07
AEO97												1.36	1.38	0.09
AEO98													1.28	0.01
Actual Value	**1.65**	**1.58**	**1.51**	**1.47**	**1.45**	**1.46**	**1.45**	**1.41**	**1.39**	**1.36**	**1.32**	**1.29**	**1.27**	
Average Absolute Error	**0.22**	**0.29**	**0.37**	**0.42**	**0.47**	**0.52**	**0.38**	**0.44**	**0.48**	**0.53**	**0.76**	**0.49**	**0.52**	**0.49**
(Percent Error)														
AEO82	18.1	28.2	39.3	50.0	59.7	70.1								44.2
AEO83	18.4	27.8	39.6	49.4	59.1	66.6					137.9			57.0
AEO84	14.7	24.4	35.2	45.5	54.9	62.2					120.5			51.0
AEO85	1.9	10.7	21.1	28.8	36.5	43.1	51.0	60.8	69.5	78.1	90.6			44.7
AEO86		2.0	11.6	19.5	26.6	32.8	41.0	51.1	60.3	71.3	84.3	94.1	103.3	49.8
AEO87			0.9	6.7	14.6	20.4	27.8	37.2	46.6	55.9	68.0			30.9
AEO89				2.3	4.9	14.7	21.1	28.3	35.5	43.3	52.7	60.0	68.7	33.1
AEO90					0.7	5.1					44.7			16.8
AEO91						3.4	9.9	18.0	27.0	36.0	44.8	52.6	60.9	31.6
AEO92							7.0	15.0	19.9	28.6	38.7	48.1	53.3	30.1
AEO93								5.5	10.0	16.5	26.7	32.8	41.1	22.1
AEO94									8.5	14.2	24.9	33.5	40.0	24.2
AEO95										4.5	10.6	14.4	20.9	12.6
AEO96											2.7	4.6	8.1	5.1
AEO97												5.1	8.7	6.9
AEO98													0.9	0.9
Average Absolute Percent Error	**13.3**	**18.6**	**24.6**	**28.9**	**32.1**	**35.4**	**26.3**	**30.9**	**34.6**	**38.7**	**57.5**	**38.4**	**40.6**	**35.3**

AEO = Annual Energy Outlook.

Btu = British thermal unit.

Sources: **Actual Values:** Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(98/05) (Washington, DC, May 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

been higher than actual. By publication, *AEO83* had the highest average absolute error of 18.2 percent, and *AEO97* had the lowest at 3.3 percent (with the exception of the *AEO98* estimate of the most recent historical year of 1997 based on partial year data). Recent *AEO*s, from the *Annual Energy Outlook 1992* (*AEO92*)[33] on, have had average absolute percent errors of 9.4 percent or less.

The primary reason for high price forecasts was the impact of fuel costs and capital costs on expected prices. Fuel costs were consistently overestimated for oil, natural gas, and coal, with a strong effect on the estimates of electricity prices, especially for *AEO82* through *AEO84*. In addition, the costs of new capacity were assumed to be higher in earlier projections than they actually turned out to be, and this assumption also helped to raise the forecasts. Finally, a 1992 study[34] on the accuracy of *AEO* electricity forecasts for 1985 and 1990 indicated that part of the explanation for high price estimates was public utility commission disallowances and phase-ins of costs of some capital-intensive generating capacity that were not incorporated in the projections because actual regulatory practices varied from those assumed in the projections. For example,

[33]Energy Information Administration, *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992).

[34]"Forecasting Accuracy of the Electricity Market Model," prepared by the Nuclear and Electricity Analysis Branch, Energy Information Administration (unpublished manuscript, July 30, 1992).

Table 16. Average Electricity Prices: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Nominal Cents per Kilowatthour)														
AEO82	6.13	6.49	6.88	7.18	7.50	7.87								0.65
AEO83	6.72	6.98	7.26	7.54	7.80	8.09					9.60			1.20
AEO84	6.63	6.88	7.14	7.38	7.59	7.84					8.85			0.96
AEO85	6.62	6.89	7.18	7.40	7.60	7.79	7.95	8.07	8.14	8.22	8.33			1.03
AEO86		6.67	6.89	7.05	7.20	7.38	7.50	7.46	7.47	7.63	7.86	8.07	8.33	0.77
AEO87			6.63	6.69	6.96	7.17	7.40	7.54	7.67	7.82	8.03			0.64
AEO89				6.50	6.78	7.13	7.39	7.54	7.62	7.77	7.93	8.09	8.32	0.76
AEO90					6.49	6.73					7.74			0.33
AEO91						6.94	7.36	7.61	7.78	8.05	8.15	8.16	8.25	0.96
AEO92							7.01	7.20	7.34	7.53	7.69	7.81	7.96	0.65
AEO93								7.19	7.30	7.43	7.62	7.72	7.91	0.65
AEO94									6.98	7.13	7.42	7.57	7.76	0.47
AEO95										6.95	7.13	7.16	7.35	0.25
AEO96											7.28	7.32	7.40	0.43
AEO97												7.03	7.21	0.22
AEO98													6.97	0.07
Actual Value	**6.40**	**6.40**	**6.40**	**6.40**	**6.50**	**6.60**	**6.70**	**6.80**	**6.90**	**6.90**	**6.90**	**6.90**	**6.90**	
Average Absolute Error	**0.26**	**0.38**	**0.60**	**0.70**	**0.74**	**0.84**	**0.73**	**0.72**	**0.64**	**0.71**	**1.07**	**0.76**	**0.85**	**0.74**
(Percent Error)														
AEO82	-4.3	1.4	7.5	12.2	15.4	19.3								10.0
AEO83	5.1	9.1	13.5	17.8	20.1	22.6					39.1			18.2
AEO84	3.6	7.5	11.6	15.3	16.8	18.7					28.3			14.6
AEO85	3.4	7.7	12.2	15.6	16.9	18.0	18.7	18.7	18.0	19.1	20.7			15.4
AEO86		4.2	7.6	10.1	10.7	11.9	11.9	9.7	8.3	10.6	13.9	17.0	20.7	11.4
AEO87			3.6	4.6	7.0	8.6	10.5	10.8	11.1	13.3	16.3			9.6
AEO89				1.5	4.3	8.0	10.2	11.0	10.4	12.5	15.0	17.2	20.6	11.1
AEO90					-0.2	2.0					12.1			4.8
AEO91						5.2	9.8	11.9	12.8	16.6	18.1	18.2	19.5	14.0
AEO92							4.6	5.9	6.4	9.1	11.5	13.1	15.3	9.4
AEO93								5.8	5.8	7.7	10.4	11.9	14.6	9.4
AEO94									1.1	3.4	7.6	9.7	12.5	6.9
AEO95										0.8	3.4	3.8	6.5	3.6
AEO96											5.5	6.1	7.2	6.3
AEO97												2.0	4.6	3.3
AEO98													1.1	1.1
Average Absolute Percent Error	**4.1**	**6.0**	**9.3**	**11.0**	**11.4**	**12.7**	**11.0**	**10.5**	**9.2**	**10.3**	**15.5**	**11.0**	**12.3**	**11.0**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

some nuclear units had significant shares of their costs disallowed, and the remaining costs were phased in on a longer time schedule than the utilities had requested, contributing to lower-than-expected prices in some years.

Gross Domestic Product

The economic forecasts in the *AEO*s are based on projections from DRI/McGraw-Hill, adjusted for EIA's world oil price projections. The forecasts for gross domestic product (GDP) show an average absolute percent error of 5.0 percent (Table 17). Most of the projections have been less than 10 percent from actual, with the exception of some of the forecasts in *AEO83*, *AEO84*, *AEO85*, *AEO86*, and *AEO89* for the mid-1990s, which ranged up to 28.9 percent above the actual GDP. In general, from *AEO82* through *AEO90*, the GDP forecasts tended to be underestimated for the earlier years and overestimated for the later years. In subsequent reports, GDP has been consistently underestimated.

The major reason for the pattern of overestimates in the longer term forecasts in the early *AEO*s is the recession that began in the latter part of 1990 and continued into 1991. The economic forecasts produced for the *AEO* are trend forecasts, which do not attempt to foresee the timing or magnitude of business cycles. The economic cycle in 1990-91 created a breakpoint in the series being used for evaluating forecast errors. Therefore, early *AEO*s did not forecast the recession and, consequently,

Table 17. Gross Domestic Product: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Nominal Billion Dollars)							
AEO82	3,939	4,306	4,733	5,201	5,712	6,288								225
AEO83	3,919	4,264	4,650	5,086	5,549	6,053					9,362			431
AEO84	3,910	4,191	4,589	5,031	5,490	5,979					9,098			392
AEO85	3,882	4,103	4,436	4,793	5,207	5,658	6,158	6,702	7,252	7,836	8,486			450
AEO86		4,203	4,434	4,741	5,015	5,371	5,795	6,244	6,726	7,270	7,875	8,524	9,226	403
AEO87			4,483	4,701	5,035	5,389	5,773	6,190	6,666	7,175	7,716			256
AEO89				4,857	5,182	5,575	6,013	6,483	6,987	7,525	8,106	8,756	9,400	524
AEO90					5,236	5,550					7,882			338
AEO91						5,457	5,695	6,078	6,399	6,738	7,145	7,607	8,099	151
AEO92							5,648	5,992	6,346	6,710	7,115	7,530	7,968	191
AEO93								5,941	6,339	6,714	7,117	7,542	7,995	180
AEO94									6,264	6,622	6,944	7,298	7,679	336
AEO95										6,761	7,090	7,418	7,837	205
AEO96											7,057	7,356	7,754	272
AEO97												7,585	7,867	132
AEO98													8,060	21
Actual Value	**4,181**	**4,422**	**4,692**	**5,050**	**5,439**	**5,744**	**5,917**	**6,244**	**6,558**	**6,947**	**7,265**	**7,636**	**8,080**	
Average Absolute Error	**277**	**209**	**152**	**187**	**244**	**284**	**182**	**210**	**285**	**356**	**676**	**347**	**388**	**325**
							(Percent Error)							
AEO82	-5.8	-2.6	0.9	3.0	5.0	9.5								4.5
AEO83	-6.2	-3.6	-0.9	0.7	2.0	5.4					28.9			6.8
AEO84	-6.5	-5.2	-2.2	-0.4	0.9	4.1					25.2			6.4
AEO85	-7.1	-7.2	-5.5	-5.1	-4.3	-1.5	4.1	7.3	10.6	12.8	16.8			7.5
AEO86		-5.0	-5.5	-6.1	-7.8	-6.5	-2.1	0.0	2.6	4.6	8.4	11.6	14.2	6.2
AEO87			-4.5	-6.9	-7.4	-6.2	-2.4	-0.9	1.6	3.3	6.2			4.4
AEO89				-3.8	-4.7	-2.9	1.6	3.8	6.5	8.3	11.6	14.7	16.3	7.4
AEO90					-3.7	-3.4					8.5			5.2
AEO91						-5.0	-3.7	-2.7	-2.4	-3.0	-1.6	-0.4	0.2	2.4
AEO92							-4.5	-4.0	-3.2	-3.4	-2.1	-1.4	-1.4	2.9
AEO93								-4.9	-3.3	-3.4	-2.0	-1.2	-1.1	2.6
AEO94									-4.5	-4.7	-4.4	-4.4	-5.0	4.6
AEO95										-2.7	-2.4	-2.9	-3.0	2.7
AEO96											-2.9	-3.7	-4.0	3.5
AEO97												-0.7	-2.6	1.7
AEO98													-0.3	0.3
Average Absolute Percent Error	**6.4**	**4.7**	**3.2**	**3.7**	**4.5**	**4.9**	**3.1**	**3.4**	**4.4**	**5.1**	**9.3**	**4.5**	**4.8**	**5.0**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1996—Council of Economic Advisors, *Economic Report of the President* (Washington, DC, February 1998). 1997—U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, April 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(82-98) (Washington, DC, April 1983 - December 1997).

overestimated long-term growth beyond 1991. Conversely, the underestimates in later *AEO*s resulted in part from overestimates of world oil prices, which tend to dampen economic growth, plus several other factors such as actual utility bond rates being lower than expected.

High and Low Economic Growth Cases

All the preceding analysis has focused on the reference case projections from the *AEO*s. In fact, all the *AEO*s have presented projections for more than one case. During the period covered in this paper, the reports have included two to six alternative cases, which have varied key reference case assumptions and examined the impacts of those assumptions across all energy markets. Most frequently, the alternative cases have varied the macroeconomic growth or world oil market assumptions, although other cases have been examined, such as different oil and gas resource base assumptions. Also, many *AEO*s have included a variety of additional cases that have analyzed the impacts of different assumptions on a portion of the energy market. *AEO98*, for example, included 28 such cases in addition to the reference case, high and low macroeconomic growth cases, and high and low world oil price cases.

To analyze the uncertainty associated with varying economic conditions, many *AEO*s included two cases with alternative economic growth rates. Where available, the domestic GDP projections for the high and low economic growth cases are presented here, along with the accompanying total energy consumption, electricity sales, and coal consumption projections in Tables 18 through Table 25. These variables were chosen because total consumption and electricity sales tend to be closely linked to economic growth, with coal consumption determined by electricity sales to a large degree. Note that *AEO85*, *AEO89*, and *AEO90* had no high or low economic growth cases, and *AEO91* included no low economic growth case.

Some caution must be used in interpreting the results from these cases. First, during the mid-1980s, attention in the *AEO*s was focused on international and domestic oil markets. In *AEO86* and *AEO87*, the high economic growth cases included low world oil price assumptions that would tend to increase projected energy consumption beyond the level caused by the higher economic growth alone. Conversely, in *AEO86* and *AEO87*, the low economic growth cases included high world oil price assumptions. The cases were designed in this way to examine the uncertainty in petroleum imports that results from changes in both prices and economic growth. The high economic growth case in *AEO91* also included the assumption of low world oil prices in order to present a case with the highest level of energy consumption from the combination of various price and growth assumptions. For all the other *AEO*s examined in this paper, the economic growth cases included moderate world oil price assumptions.

The second cautionary note concerns the definition of the economic growth cases. Through the years, the low and high economic growth cases have sometimes been defined by varying only the growth in economic output. At other times, labor productivity (output per person), labor force growth rates, and population have also varied at different rates for the high and low economic growth cases. In addition, some of the *AEO*s attempted to define a broad band of uncertainty around the reference case projections of economic growth rate, while others defined a more narrow range. In short, the definitions of the economic growth cases have not been consistent. Nevertheless, the presentation of these results should highlight some of the ranges of the forecasts presented over the years.

Table 18. Total Energy Consumption, Low Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Quadrillion Btu)							
AEO84	75.3	76.4	77.9	78.8	79.6	83.5					89.2			1.4
AEO86		74.2	75.3	76.0	76.3	80.2					84.4			3.6
AEO87			76.2	76.6	77.8	81.6	82.2	83.1	84.0	85.1	85.8			3.1
AEO90					84.0	84.2					89.8			1.3
AEO92							84.5	86.6	87.5	88.7	90.0	90.7	91.5	1.3
AEO93								87.0	87.5	89.2	90.5	91.3	92.3	1.1
AEO94									87.8	89.0	89.9	90.6	91.4	1.6
AEO95										89.2	89.4	89.8	90.9	2.3
AEO96											90.3	90.5	91.4	2.3
AEO97												92.6	93.5	1.0
AEO98													94.7	0.5
Actual Value	**74.0**	**74.3**	**76.9**	**80.2**	**81.4**	**84.1**	**84.0**	**85.6**	**87.4**	**89.3**	**90.9**	**93.9**	**94.2**	
Average Absolute Error	**1.3**	**1.1**	**1.1**	**3.1**	**3.3**	**1.8**	**1.2**	**1.6**	**1.0**	**1.1**	**2.1**	**3.0**	**2.1**	**2.0**
							(Percent Error)							
AEO84	1.8	2.8	1.2	-1.8	-2.3	-0.7					-1.9			1.8
AEO86		-0.1	-2.1	-5.2	-6.2	-4.7					-7.2			4.3
AEO87			-0.9	-4.5	-4.4	-3.0	-2.2	-2.9	-3.9	-4.7	-5.7			3.6
AEO90					3.2	0.1					-1.3			1.5
AEO92							0.6	1.2	0.1	-0.7	-1.1	-3.4	-2.9	1.4
AEO93								1.6	0.1	-0.1	-0.4	-2.8	-2.0	1.2
AEO94									0.5	-0.3	-1.1	-3.5	-3.0	1.7
AEO95										-0.1	-1.7	-4.4	-3.5	2.4
AEO96											-0.7	-3.7	-3.0	2.4
AEO97												-1.4	-0.7	1.0
AEO98													0.5	0.5
Average Absolute Percent Error	**1.8**	**1.5**	**1.4**	**3.8**	**4.0**	**2.1**	**1.4**	**1.9**	**1.1**	**1.2**	**2.3**	**3.2**	**2.2**	**2.3**

AEO = Annual Energy Outlook.

Btu = British thermal unit.

Note: Includes nonelectric renewables.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

Overall, the GDP projections for both the low and high economic growth assumptions (Tables 21 and 25) have lower error rates—average absolute percent errors of 4.6 and 3.9, respectively—than the reference case projections (5.0 percent average). In part, this is because the *AEO*s with the worst errors for the reference case GDP had no economic growth cases (*AEO82*, *AEO83*, *AEO85*, and *AEO89*). Excluding these reports and *AEO91*, which had no low growth case, yields average absolute percent errors of 4.6, 4.4, and 3.7 percent for the low, reference and high growth cases, respectively. The largest errors are for the year 1995 in the earlier *AEO*s; as a result, those *AEO*s have the highest average absolute percent errors in all cases. In the later *AEO*s, GDP was consistently underestimated in both the high and low economic growth cases. The low and high growth GDP paths, in real terms, bracket the reference case. In the short term, low economic growth results from higher prices, which lead to a higher set of deflators and some apparent anomalies—with nominal GDP in the low growth case higher than in the reference case, as in the *AEO94* projections for 1993 to 1997.

Total energy consumption in the low economic growth case (Table 18) shows a larger average absolute percent error (2.3 percent) than in the reference and high growth cases (1.7 and 1.6 percent, respectively). The majority of the errors in the reference case were underestimations, many of which became even worse with the lower economic growth assumptions and were further exacerbated by the *AEO*s with high world oil price assumptions (*AEO86* and *AEO87*).

Coal consumption errors appear worse in the low and high economic growth cases (Table 19 and Table 23), with average absolute percent errors of 3.5 percent and 3.4 percent, respectively, compared with 3.0 percent for the reference case. When the *AEO*s with no economic growth cases (*AEO82*, *AEO83*, *AEO85*, and *AEO89*) are eliminated, some of the smaller errors in the reference case are eliminated, raising the average absolute percent error to 3.4 percent for the reference case, similar to those in the high and low growth cases.

The average absolute percent error for total electricity sales in the low economic growth case (Table 20) is higher at 2.4 percent than those in the reference and high economic growth cases (1.7 and 1.6 percent, respectively). In the reference cases, most *AEO*s tended to underestimate electricity sales in most years; however,

Table 19. Total Coal Consumption, Low Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Million Short Tons)							
AEO84	843	847	859	869	890	922					1,060			33
AEO86		813	830	856	865	882					1,010			22
AEO87			837	838	851	873	887	902	921	943	962			16
AEO90					880	888					974			10
AEO92							905	932	915	921	931	941	948	39
AEO93								927	926	935	941	949	958	34
AEO94									918	922	925	929	932	53
AEO95										936	937	936	940	50
AEO96											937	938	947	58
AEO97												948	969	58
AEO98													1,008	19
Actual Value	**818**	**804**	**837**	**884**	**890**	**896**	**888**	**908**	**944**	**952**	**962**	**1,006**	**1,027**	
Average Absolute Error	**25**	**26**	**10**	**30**	**19**	**18**	**9**	**16**	**24**	**21**	**33**	**66**	**70**	**34**
							(Percent Error)							
AEO84	3.1	5.3	2.6	-1.7	0.0	2.9					10.2			3.7
AEO86		1.1	-0.8	-3.2	-2.8	-1.6					5.0			2.4
AEO87			0.0	-5.2	-4.4	-2.6	-0.1	-0.7	-2.4	-0.9	0.0			1.8
AEO90					-1.1	-0.9					1.2			1.1
AEO92							1.9	2.6	-3.1	-3.3	-3.2	-6.5	-7.7	4.0
AEO93								2.1	-1.9	-1.8	-2.2	-5.7	-6.7	3.4
AEO94									-2.8	-3.2	-3.8	-7.7	-9.3	5.3
AEO95										-1.7	-2.6	-7.0	-8.5	4.9
AEO96											-2.6	-6.8	-7.8	5.7
AEO97												-5.8	-5.6	5.7
AEO98													-1.9	1.9
Average Absolute Percent Error	**3.1**	**3.2**	**1.2**	**3.4**	**2.1**	**2.0**	**1.0**	**1.8**	**2.5**	**2.2**	**3.4**	**6.5**	**6.8**	**3.5**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

the underestimates were exacerbated by the lower economic growth assumptions leading to the larger average errors in the low economic growth cases.

Across comparable *AEO*s, the reference case tended to underestimate GDP growth. Therefore, in the low economic growth cases, error rates for GDP and consumption were exacerbated. Error rates in the high economic growth cases tended to be equal to or slightly lower than those in the reference case.

Regression Analysis on Historical Data

Methodology

All the preceding analyses have focused on comparing the projections from previous *AEO*s with actual historical values. This section describes simple regression analyses on historic data for the 16 variables from Table 1, as recommended by reviewers of an earlier version of this paper. The results of the regressions are compared with actual values to determine whether a simple trend analysis would have performed better than the *AEO* models. (There are other time series or trend analysis models, such as vector autoregression (VAR), Bayesian vector autoregression (BVAR), or moving averages, that could also be used for comparisons with the *AEO* forecasts and may prove better than a simple regression analysis.) Historical data for the regressions were obtained from the *Annual Energy Review 1996*,[35] and in most cases go back to 1950.

A simple lag regression was performed for each of the 16 variables, using the following estimation equation:

$$Y_i(t) = A + B \times Y_i(t-1) \ ,$$

where i = 1, . . ., 16. Two sets of estimations were made—TREND 85 and TREND 90. TREND 85, for a given energy variable, is the result of a simple trend analysis, or regression, in which the one independent variable is the energy term lagged one year, and the last historical year is 1985. TREND 90 has the same definition, except that the last historical year is 1990. Appendix A provides an example of the estimation performed for total energy consumption.

Table 20. Total Electricity Sales, Low Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
						(Billion Kilowatthours)								
AEO84	2,321	2,374	2,440	2,493	2,548	2,627					3,015			42
AEO86		2,360	2,409	2,470	2,520	2,590					3,004			71
AEO87			2,460	2,494	2,545	2,602	2,653	2,711	2,781	2,858	2,928			78
AEO90					2,607	2,653					3,012			34
AEO92							2,736	2,823	2,838	2,891	2,951	3,002	3,052	54
AEO93								2,803	2,824	2,877	2,920	2,958	3,002	81
AEO94									2,837	2,874	2,903	2,928	2,961	105
AEO95										2,951	2,945	2,958	2,993	88
AEO96											2,964	2,970	3,002	98
AEO97												3,075	3,115	14
AEO98													3,106	14
Actual Value	**2,324**	**2,369**	**2,457**	**2,578**	**2,647**	**2,713**	**2,762**	**2,763**	**2,861**	**2,935**	**3,013**	**3,098**	**3,120**	
Average Absolute Error	**3**	**7**	**23**	**92**	**92**	**95**	**68**	**51**	**41**	**51**	**53**	**116**	**87**	**68**
						(Percent Error)								
AEO84	-0.1	0.2	-0.7	-3.3	-3.7	-3.2					0.1			1.6
AEO86		-0.4	-2.0	-4.2	-4.8	-4.5					-0.3			2.7
AEO87			0.1	-3.3	-3.9	-4.1	-3.9	-1.9	-2.8	-2.6	-2.8			2.8
AEO90					-1.5	-2.2					0.0			1.3
AEO92							-0.9	2.2	-0.8	-1.5	-2.1	-3.1	-2.2	1.8
AEO93								1.4	-1.3	-2.0	-3.1	-4.5	-3.8	2.7
AEO94									-0.8	-2.1	-3.7	-5.5	-5.1	3.4
AEO95										0.5	-2.3	-4.5	-4.1	2.8
AEO96											-1.6	-4.1	-3.8	3.2
AEO97												-0.7	-0.2	0.5
AEO98													-0.4	0.4
Average Absolute Percent Error . . .	**0.1**	**0.3**	**0.9**	**3.6**	**3.5**	**3.5**	**2.4**	**1.8**	**1.4**	**1.7**	**1.8**	**3.7**	**2.8**	**2.4**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

[35] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997).

- **TREND 85:** Sixteen estimations were performed, one for each variable in Table 1. The total energy consumption example had 36 observations, 1950 to 1985. After the coefficients, *A* and *B*, were determined, the above equation was used to compute the values for the forecast period, 1986 to 1997. The values in the total energy (*TE*) column of Appendix A for years 1986 to 1997 correspond to the TREND 85 row for total energy consumption in Table 26. The estimations were repeated for the remaining 15 variables, with the results shown in Table 26 in the TREND 85 rows.

- **TREND 90:** The methodology for determining the TREND 90 rows in Table 26 was the same as for TREND 85, except that there were 41 observations for the time period 1950 to 1990. After the coefficients were determined, the values were computed for the forecast period 1991 to 1997. The results are shown in the TREND 90 rows of Table 26.

Table 26 also contains, for each energy variable, the average absolute percent errors between *AEO86*, TREND 85, *AEO92*, and TREND 90, compared with the actual values. *AEO86* corresponds to TREND 85 because the first forecast year is 1986. Similarly, the first forecast year for *AEO92* and TREND 90 is 1991.[36]

Results

In general, the trend regressions had higher average absolute percent errors than the *AEO* projections (Table 26). Trend regressions do not pick up major reversals that occur in the forecast period. For example, for crude oil production, which declined steadily after 1991, both TREND 85 and TREND 90 overestimated by a large amount, whereas the *AEO*s, especially *AEO92*, were better at picking up the turnaround.

Trend analysis did poorly for price paths, especially when the directions of the price paths changed. For example, average electricity prices were initially flat,

Table 21. Gross Domestic Product, Low Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Nominal Billion Dollars)														
AEO84	3,863	4,147	4,574	5,034	5,522	6,062					9,982			549
AEO86		4,196	4,422	4,734	5,002	5,356					7,808			363
AEO87			4,483	4,716	5,076	5,446	5,846	6,283	6,789	7,347	7,924			289
AEO90					5,216	5,472					8,212			480
AEO92							5,569	5,830	6,285	6,636	7,015	7,567	8,129	245
AEO93								5,941	6,204	6,605	6,974	7,408	7,946	275
AEO94									6,273	6,678	7,096	7,554	8,042	169
AEO95										6,755	7,096	7,526	8,065	122
AEO96											7,064	7,398	7,883	212
AEO97												7,583	7,919	107
AEO98													8,064	16
Actual Value	**4,181**	**4,422**	**4,692**	**5,050**	**5,439**	**5,744**	**5,917**	**6,244**	**6,558**	**6,947**	**7,265**	**7,636**	**8,080**	
Average Absolute Error	**318**	**251**	**199**	**222**	**276**	**319**	**209**	**252**	**286**	**303**	**661**	**130**	**87**	**295**
(Percent Error)														
AEO84	-7.6	-6.2	-2.5	-0.3	1.5	5.5					37.4			8.7
AEO86		-5.1	-5.8	-6.3	-8.0	-6.8					7.5			6.6
AEO87			-4.5	-6.6	-6.7	-5.2	-1.2	0.6	3.5	5.8	9.1			4.8
AEO90					-4.1	-4.7					13.0			7.3
AEO92							-5.9	-6.6	-4.2	-4.5	-3.4	-0.9	0.6	3.7
AEO93								-4.9	-5.4	-4.9	-4.0	-3.0	-1.7	4.0
AEO94									-4.3	-3.9	-2.3	-1.1	-0.5	2.4
AEO95										-2.8	-2.3	-1.4	-0.2	1.7
AEO96											-2.8	-3.1	-2.4	2.8
AEO97												-0.7	-2.0	1.3
AEO98													-0.2	0.2
Average Absolute Percent Error	**7.6**	**5.7**	**4.2**	**4.4**	**5.1**	**5.6**	**3.5**	**4.0**	**4.4**	**4.4**	**9.1**	**1.7**	**1.1**	**4.6**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1996—Council of Economic Advisors, *Economic Report of the President* (Washington, DC, February 1998). 1997—U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, April 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

[36]The 1988 report was titled *AEO87*, and the first forecast year was 1987. In 1989 the numbering scheme changed and that year's report was titled *AEO89*, with the first forecast year being 1988. Subsequent *AEO*s have followed this scheme. Hence, in 1992, *AEO92* had 1991 as its first forecast year.

rose from 1989 to 1993, then flattened again. TREND 85 overestimated future electricity prices by a large margin, but *AEO86* did better. Another example is natural gas wellhead prices, which TREND 85 tended to overestimate and TREND 90 to underestimate; however, the *AEO*s also did poorly at catching the turns in the price path, even though *AEO86* performed better than TREND 85.

Of the 16 variables examined in this analysis, *AEO86* had lower average absolute percent errors than TREND 85 for 10 of the variables. Even for the 6 variables for which TREND 85 had a lower error rate, the differences between the average absolute percent errors for *AEO86* and TREND 85 were less than 1 percent for 3 of them. For all the consumption, production, import, and macroeconomic variables, *AEO92* was consistently better than TREND 90, with the exception of natural gas production and coal exports. In the case of gas production, the average absolute percent errors for the two analyses differed by less than 1 percent. For the price variables, TREND 90 performed somewhat better than *AEO92*, although average absolute percentage errors for the two analyses were the same for electricity prices and both had relatively high error rates for all other prices.

In conclusion, a simple trend analysis model of the type used in this report does not pick up major reversals occurring in the forecast period; does poorly where many turns occur; and does not pick up the effects of legislative actions or regulations on the forecast.

Conclusion

Although a primary function of the models used by EIA to produce its *AEO* forecasts has been and remains the analysis of alternative policies, many readers of the *AEO* use the projected numbers as forecasts for their own purposes. Thus, it is useful for EIA analysts and users of the *AEO* to know the size of and reasons for the differences between the projections and actual values.

Table 22. Total Energy Consumption, High Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
(Quadrillion Btu)														
AEO84	76.0	77.2	79.6	81.9	83.8	88.9					98.3			3.4
AEO86		74.3	77.2	78.3	79.0	83.2					88.2			1.4
AEO87			76.2	77.7	79.9	84.5	86.0	87.4	88.6	89.6	90.6			1.2
AEO90					84.3	86.4					93.7			2.7
AEO91						84.4	85.4	87.3	88.8	90.4	92.0	93.6	95.2	1.0
AEO92							84.7	87.1	88.2	89.5	91.1	92.6	93.9	0.7
AEO93								87.0	88.9	90.6	92.3	93.9	95.5	1.1
AEO94									88.2	90.2	91.7	93.0	94.2	0.7
AEO95										89.2	90.7	91.6	93.1	0.9
AEO96											90.8	92.1	93.8	0.8
AEO97												92.7	93.6	0.9
AEO98													94.7	0.5
Actual Value	**74.0**	**74.3**	**76.9**	**80.2**	**81.4**	**84.1**	**84.0**	**85.6**	**87.4**	**89.3**	**90.9**	**93.9**	**94.2**	
Average Absolute Error	**2.0**	**1.5**	**1.3**	**2.0**	**2.3**	**1.7**	**1.4**	**1.6**	**1.1**	**0.6**	**1.7**	**1.1**	**0.6**	**1.4**
(Percent Error)														
AEO84	2.7	3.9	3.6	2.1	3.0	5.7					8.1			4.2
AEO86		0.0	0.4	-2.4	-3.0	-1.1					-3.0			1.7
AEO87			-0.9	-3.2	-1.9	0.4	2.4	2.1	1.4	0.3	-0.3			1.4
AEO90					3.6	2.7					3.0			3.1
AEO91						0.4	1.7	2.0	1.6	1.2	1.2	-0.3	1.1	1.2
AEO92							0.8	1.8	0.9	0.2	0.2	-1.4	-0.3	0.8
AEO93								1.6	1.7	1.5	1.5	0.0	1.4	1.3
AEO94									0.9	1.0	0.8	-1.0	0.0	0.7
AEO95										-0.1	-0.3	-2.4	-1.2	1.0
AEO96											-0.2	-1.9	-0.4	0.8
AEO97												-1.3	-0.6	1.0
AEO98													0.5	0.5
Average Absolute Percent Error	**2.7**	**2.0**	**1.6**	**2.6**	**2.9**	**2.1**	**1.6**	**1.9**	**1.3**	**0.7**	**1.9**	**1.2**	**0.7**	**1.6**

AEO = Annual Energy Outlook.
Btu = British thermal unit.
Note: Includes nonelectric renewables.
Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

Throughout the *AEO*s, the variables with the highest errors, expressed as average absolute percent errors, have been prices and net imports of natural gas and coal. Natural gas, in general, has been the fuel with the most inaccurate forecasts, showing the highest average error of all the fuels for consumption, production, and prices. Natural gas was the last fossil fuel to be deregulated following the heavy regulation of energy markets in the 1970s and early 1980s, and the early *AEO*s assumed that natural gas would continue to be regulated until new rules were actually promulgated. Even after deregulation, the behavior of natural gas in competitive markets was difficult to predict.

The overestimation of prices is the most striking feature of this evaluation. In general, more rapid technological improvements, the erosion of OPEC's market power, excess productive capacity, and market competitiveness were the factors that the *AEO* forecasts failed to anticipate. While the errors for prices were large, they appeared to have a relatively minor impact on the overall projections of demand and production, although some forecasts were clearly affected, possibly confirming the relatively low price elasticities of supply and demand embedded in the models. For the period covered by this study, productivity and technology improvements and the effects of gradual deregulation and changes in industry structure, such as the treatment of contracts, have more than offset the factors that have tended to raise fossil fuel prices. In addition, energy markets have evolved differently than projected as a result of changes in the regulatory environment and the enactment of changes in legislation, regulations, and standards.

Caution should be used in drawing conclusions from the analysis of economic growth cases. First, these cases did not have consistent world oil price assumptions (low, mid, and high). Second, the definition of the economic growth cases varied for different *AEO*s. In general, for the GDP and consumption variables compared, the low growth cases had higher error rates than the reference

Table 23. Total Coal Consumption, High Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
						(Million Short Tons)								
AEO84	843	853	878	907	944	986					1,148			67
AEO86		813	833	856	875	896					1,031			21
AEO87			837	839	854	882	903	920	939	959	983			17
AEO90					886	900					988			11
AEO91						893	901	919	934	945	950	964	974	19
AEO92							905	933	920	926	936	949	958	35
AEO93								927	931	940	948	959	969	27
AEO94									921	933	941	949	954	39
AEO95										936	944	947	955	41
AEO96											940	947	964	48
AEO97												948	971	57
AEO98													1,009	18
Actual Value	**818**	**804**	**837**	**884**	**890**	**896**	**888**	**908**	**944**	**952**	**962**	**1,006**	**1,027**	
Average Absolute Error	**25**	**29**	**15**	**32**	**27**	**22**	**15**	**17**	**15**	**15**	**42**	**54**	**58**	**32**
						(Percent Error)								
AEO84	3.1	6.1	4.9	2.6	6.1	10.0					19.3			7.4
AEO86		1.1	-0.5	-3.2	-1.7	0.0					7.2			2.3
AEO87			0.0	-5.1	-4.0	-1.6	1.7	1.3	-0.5	0.7	2.2			1.9
AEO90					-0.4	0.4					2.7			1.2
AEO91						-0.3	1.5	1.2	-1.1	-0.7	-1.2	-4.2	-5.2	1.9
AEO92							1.9	2.8	-2.5	-2.7	-2.7	-5.7	-6.7	3.6
AEO93								2.1	-1.4	-1.3	-1.5	-4.7	-5.6	2.8
AEO94									-2.4	-2.0	-2.2	-5.7	-7.1	3.9
AEO95										-1.7	-1.9	-5.9	-7.0	4.1
AEO96											-2.3	-5.9	-6.1	4.8
AEO97												-5.8	-5.5	5.6
AEO98													-1.8	1.8
Average Absolute Percent Error	**3.1**	**3.6**	**1.8**	**3.6**	**3.1**	**2.5**	**1.7**	**1.8**	**1.6**	**1.5**	**4.3**	**5.4**	**5.6**	**3.4**

AEO = *Annual Energy Outlook.*

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

cases when comparing across the *AEO*s that had low economic growth cases. In general, reference case projections underestimated economic growth, and the high growth cases thus tended to have lower or similar error rates for the variables compared.

The most striking result of the regression analysis described here is that a simple trend analysis model of the type used does not perform well for projections where many turns occur. This is especially true for major reversals in the forecast period. Trend analysis also does not pick up technological improvements or regulatory or legislative changes. *AEO86* was better than its comparable trend analysis for the majority of the variables examined. With the exception of natural gas production and coal exports, *AEO92* consistently outperformed its comparable trend analysis for all nonprice variables. *AEO92* and the trend analysis had similar errors for electricity prices, and although the trend analysis was better than the *AEO*s for all other prices, both had relatively high error rates.

Table 24. Total Electricity Sales, High Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
						(Billion Kilowatthours)								
AEO84	2,321	2,387	2,497	2,608	2,717	2,838					3,376			93
AEO86		2,364	2,424	2,490	2,550	2,634					3,095			64
AEO87			2,460	2,496	2,568	2,647	2,720	2,790	2,867	2,942	3,022			36
AEO90					2,616	2,725					3,156			62
AEO91						2,700	2,764	2,833	2,903	2,971	3,041	3,112	3,183	34
AEO92							2,745	2,841	2,867	2,925	2,996	3,064	3,131	25
AEO93								2,803	2,855	2,918	2,983	3,046	3,111	26
AEO94									2,848	2,910	2,958	3,001	3,051	52
AEO95										2,951	2,988	3,017	3,069	43
AEO96											2,978	3,025	3,078	50
AEO97												3,075	3,115	14
AEO98													3,106	14
Actual Value	**2,324**	**2,369**	**2,457**	**2,578**	**2,647**	**2,713**	**2,762**	**2,763**	**2,861**	**2,935**	**3,013**	**3,098**	**3,120**	
Average Absolute Error	**3**	**12**	**25**	**67**	**69**	**59**	**20**	**54**	**15**	**19**	**79**	**53**	**33**	**45**
						(Percent Error)								
AEO84	-0.1	0.8	1.6	1.2	2.6	4.6					12.0			3.3
AEO86		-0.2	-1.3	-3.4	-3.7	-2.9					2.7			2.4
AEO87			0.1	-3.2	-3.0	-2.4	-1.5	1.0	0.2	0.2	0.3			1.3
AEO90					-1.2	0.4					4.7			2.1
AEO91						-0.5	0.1	2.5	1.5	1.2	0.9	0.5	2.0	1.1
AEO92							-0.6	2.8	0.2	-0.3	-0.6	-1.1	0.4	0.9
AEO93								1.4	-0.2	-0.6	-1.0	-1.7	-0.3	0.9
AEO94									-0.5	-0.9	-1.8	-3.1	-2.2	1.7
AEO95										0.5	-0.8	-2.6	-1.6	1.4
AEO96											-1.2	-2.4	-1.3	1.6
AEO97												-0.7	-0.2	0.5
AEO98													-0.4	0.4
Average Absolute Percent Error	**0.1**	**0.5**	**1.0**	**2.6**	**2.6**	**2.2**	**0.7**	**1.9**	**0.5**	**0.6**	**2.6**	**1.7**	**1.1**	**1.6**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** Energy Information Administration (EIA), *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

Table 25. Gross Domestic Product, High Economic Growth Case: *AEO* Forecasts, Actual Values, and Absolute and Percent Errors, 1985-1997

Publication	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Error
							(Nominal Billion Dollars)							
AEO84	3,932	4,225	4,643	5,110	5,577	6,068					8,957			387
AEO86		4,209	4,448	4,745	5,020	5,380					7,934			369
AEO87			4,483	4,702	5,011	5,373	5,767	6,185	6,649	7,127	7,665			248
AEO90					5,257	5,630					7,492			174
AEO91						5,457	5,832	6,296	6,774	7,270	7,796	8,343	8,912	379
AEO92							5,670	6,068	6,459	6,859	7,293	7,734	8,158	116
AEO93								5,941	6,443	6,855	7,277	7,708	8,137	109
AEO94									6,268	6,637	6,952	7,283	7,636	
AEO95										6,780	7,141	7,469	7,861	
AEO96											7,066	7,399	7,804	237
AEO97												7,608	7,938	85
AEO98													8,061	19
Actual Value	**4,181**	**4,422**	**4,692**	**5,050**	**5,439**	**5,744**	**5,917**	**6,244**	**6,558**	**6,947**	**7,265**	**7,636**	**8,080**	
Average Absolute Error	**249**	**205**	**168**	**238**	**291**	**292**	**160**	**148**	**130**	**171**	**470**	**228**	**234**	**252**
							(Percent Error)							
AEO84	-5.9	-4.5	-1.0	1.2	2.5	5.6					23.3			6.3
AEO86		-4.8	-5.2	-6.0	-7.7	-6.3					9.2			6.5
AEO87			-4.5	-6.9	-7.9	-6.5	-2.5	-1.0	1.4	2.6	5.5			4.3
AEO90					-3.3	-2.0					3.1			2.8
AEO91						-5.0	-1.4	0.8	3.3	4.6	7.3	9.3	10.3	5.3
AEO92							-4.2	-2.8	-1.5	-1.3	0.4	1.3	1.0	1.8
AEO93								-4.9	-1.8	-1.3	0.2	0.9	0.7	1.6
AEO94									-4.4	-4.5	-4.3	-4.6	-5.5	4.7
AEO95										-2.4	-1.7	-2.2	-2.7	2.3
AEO96											-2.7	-3.1	-3.4	3.1
AEO97												-0.4	-1.8	1.1
AEO98													-0.2	0.2
Average Absolute Percent Error	**5.9**	**4.6**	**3.6**	**4.7**	**5.4**	**5.1**	**2.7**	**2.4**	**2.5**	**2.8**	**5.8**	**3.1**	**3.2**	**3.9**

AEO = Annual Energy Outlook.

Sources: **Actual Values:** 1985-1996—Council of Economic Advisors, *Economic Report of the President* (Washington, DC, February 1998). 1997—U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, April 1998). **Projections:** EIA, *Annual Energy Outlook*, DOE/EIA-0383(84-98) (Washington, DC, January 1985 - December 1997).

Table 26. Energy Variables: Actual Values, *AEO* Forecasts, Trend Analyses, and Absolute Percent Errors, 1985-1997

Value	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Average Absolute Percent Error
Total Energy Consumption (Quadrillion Btu)														
Actual	74.0	74.3	76.9	80.2	81.4	84.1	84.0	85.6	87.4	89.3	90.9	93.9	94.2	
AEO86	74.0	74.3	76.1	77.0	77.5	81.5	82.9	84.0	84.8	85.7	86.5	87.9	88.4	3.4
TREND 85	74.0	74.7	75.3	76.0	76.6	77.2	77.8	78.4	79.0	79.5	80.0	80.5	81.0	8.2
AEO92						84.1	84.7	87.0	88.0	89.2	90.5	91.4	92.4	1.2
TREND 90						84.1	84.1	85.0	85.8	86.7	87.5	88.3	89.1	3.0
Total Petroleum Consumption (Million Barrels per Day)														
Actual	15.73	16.28	16.67	17.28	17.33	16.99	16.71	17.03	17.24	17.72	17.72	18.31	18.58	
AEO86	15.73	16.07	16.29	16.05	16.07	16.15	16.31	16.37	16.42	16.44	16.46	16.50	16.64	5.7
TREND 85	15.73	15.86	15.99	16.11	16.23	16.34	16.45	16.55	16.64	16.74	16.82	16.91	16.99	4.9
AEO92						16.99	16.74	17.07	17.37	17.59	17.80	17.86	17.99	1.1
TREND 90						16.99	17.10	17.20	17.31	17.40	17.49	17.58	17.67	2.2
Total Natural Gas Consumption (Trillion Cubic Feet)														
Actual	17.28	16.22	17.21	18.03	18.80	18.72	19.04	19.54	20.28	20.71	21.58	21.97	21.99	
AEO86	17.28	16.52	16.83	17.35	17.27	17.50	17.77	17.77	17.90	18.01	18.04	18.03	18.26	9.5
TREND 85	17.28	17.49	17.69	17.87	18.05	18.21	18.37	18.51	18.65	18.78	18.90	19.01	19.12	6.9
AEO92						18.72	18.79	19.36	19.84	20.08	20.53	20.68	21.12	3.2
TREND 90						18.72	18.86	18.98	19.10	19.22	19.32	19.42	19.52	7.2
Total Coal Consumption (Million Short Tons)														
Actual	818	804	837	884	890	896	888	908	944	952	962	1,006	1,027	
AEO86	818	813	831	860	870	888	919	945	972	995	1,021	1,038	1,051	2.9
TREND 85	818	845	874	905	938	972	1,009	1,048	1,089	1,133	1,180	1,229	1,281	13.2
AEO92						896	905	934	919	925	934	944	953	3.8
TREND 90						896	918	942	967	992	1,019	1,046	1,075	4.0
Total Electricity Sales (Billion Kilowatthours)														
Actual	2,324	2,369	2,457	2,578	2,647	2,713	2,762	2,763	2,861	2,935	3,013	3,098	3,120	
AEO86	2,324	2,363	2,416	2,479	2,533	2,608	2,706	2,798	2,883	2,966	3,048	3,116	3,185	1.9
TREND 85	2,324	2,391	2,458	2,526	2,595	2,664	2,733	2,804	2,875	2,946	3,018	3,090	3,164	1.0
AEO92						2,713	2,746	2,845	2,858	2,913	2,975	3,030	3,087	1.3
TREND 90						2,713	2,787	2,862	2,938	3,015	3,093	3,171	3,251	2.7
Crude Oil Production (Million Barrels per Day)														
Actual	8.97	8.68	8.35	8.14	7.61	7.36	7.42	7.17	6.85	6.66	6.56	6.46	6.41	
AEO86	8.97	8.80	8.63	8.30	7.90	7.43	6.95	6.60	6.36	6.20	5.99	5.80	5.66	5.9
TREND 85	8.97	8.98	8.98	8.99	8.99	8.99	9.00	9.00	9.00	9.00	9.01	9.01	9.01	24.4
AEO92						7.36	7.37	7.17	6.99	6.89	6.68	6.45	6.28	1.5
TREND 90						7.36	7.47	7.58	7.67	7.75	7.83	7.89	7.95	14.3
Natural Gas Production (Trillion Cubic Feet)														
Actual	16.45	16.06	16.62	17.10	17.31	17.81	17.70	17.84	18.10	18.82	18.60	18.79	18.96	
AEO86	16.45	16.30	16.27	17.15	16.68	16.90	16.97	16.87	16.93	16.86	16.62	16.40	16.33	6.4
TREND 85	16.45	16.67	16.87	17.06	17.24	17.41	17.56	17.71	17.84	17.97	18.08	18.19	18.30	2.1
AEO92						17.81	17.43	17.69	17.95	18.00	18.29	18.27	18.51	2.1
TREND 90						17.81	17.95	18.08	18.20	18.31	18.42	18.52	18.61	1.5
Coal Production (Million Short Tons)														
Actual	884	890	919	950	981	1,029	996	998	945	1,034	1,033	1,064	1,089	
AEO86	884	890	920	954	962	983	1,017	1,044	1,073	1,097	1,126	1,142	1,156	4.6
TREND 85	884	895	907	918	930	941	953	964	976	987	999	1,010	1,022	4.1
AEO92						1,029	1,004	1,040	1,019	1,034	1,052	1,064	1,074	2.3
TREND 90						1,029	1,053	1,078	1,103	1,129	1,155	1,182	1,210	10.5
Net Petroleum Imports (Million Barrels per Day)														
Actual	4.29	5.44	5.91	6.59	7.20	7.16	6.63	6.94	7.62	8.05	7.89	8.50	8.90	
AEO86	4.29	5.15	5.38	5.46	5.92	6.46	7.09	7.50	7.78	7.96	8.20	8.47	8.74	6.9
TREND 85	4.29	4.35	4.40	4.46	4.51	4.56	4.60	4.64	4.69	4.73	4.76	4.80	4.83	35.3
AEO92						7.16	6.86	7.42	7.88	8.16	8.55	8.80	9.06	4.1
TREND 90						7.16	7.23	7.30	7.37	7.43	7.50	7.56	7.62	7.9

See notes at end of table.

Table 26. Energy Variables: Actual Values, *AEO* Forecasts, Trend Analyses, and Absolute Percent Errors, 1985-1997 (Continued)

Net Natural Gas Imports (Trillion Cubic Feet)														
Actual	0.89	0.69	0.94	1.22	1.28	1.45	1.64	1.92	2.21	2.46	2.69	2.78	2.82	
AEO86	0.89	0.74	0.88	0.62	1.03	1.05	1.27	1.39	1.47	1.66	1.79	1.96	2.17	26.0
TREND 85	0.89	0.91	0.92	0.93	0.94	0.95	0.96	0.97	0.98	0.99	0.99	1.00	1.01	43.1
AEO92						1.45	1.48	1.62	1.88	2.08	2.25	2.41	2.56	13.6
TREND 90						1.45	1.48	1.51	1.55	1.58	1.61	1.65	1.68	31.2
Net Coal Exports (Million Short Tons)														
Actual	91	83	78	93	98	103	106	99	67	64	81	83	76	
AEO86	91	87	87	88	89	91	92	94	96	98	100	101	102	19.7
TREND 85	91	84	79	75	72	70	68	67	66	66	65	65	64	17.4
AEO92						103	98	99	103	109	116	117	120	39.1
TREND 90						103	97	92	88	85	82	80	78	12.5
World Oil Prices (Nominal Dollars per Barrel)														
Actual	26.99	14.00	18.13	14.56	18.08	21.76	18.70	18.20	16.14	15.51	17.14	20.64	18.58	
AEO86	26.99	14.57	15.89	17.28	18.91	20.72	22.20	24.74	28.25	32.02	35.52	38.48	41.36	49.7
TREND 85	26.99	27.58	28.12	28.63	29.09	29.52	29.92	30.29	30.63	30.94	31.24	31.50	31.75	72.2
AEO92						21.76	19.13	20.19	20.72	22.19	23.91	25.55	27.52	28.0
TREND 90						21.76	21.91	22.04	22.15	22.25	22.33	22.41	22.47	25.5
Natural Gas Wellhead Prices (Nominal Dollars per Thousand Cubic Feet)														
Actual	2.51	1.94	1.67	1.69	1.69	1.71	1.64	1.74	2.04	1.85	1.55	2.17	2.42	
AEO86	2.51	1.73	1.96	2.29	2.55	2.82	3.14	3.64	4.12	4.65	5.25	5.83	6.41	100.4
TREND 85	2.51	2.72	2.95	3.19	3.46	3.74	4.04	4.36	4.71	5.08	5.48	5.90	6.36	135.0
AEO92						1.71	1.69	1.86	2.04	2.14	2.32	2.44	2.63	13.8
TREND 90						1.71	1.74	1.77	1.80	1.83	1.86	1.89	1.92	10.6
Coal Prices to Electric Utilities (Nominal Dollars per Million Btu)														
Actual	1.65	1.58	1.51	1.47	1.45	1.46	1.45	1.41	1.39	1.36	1.32	1.29	1.27	
AEO86	1.65	1.61	1.68	1.75	1.84	1.94	2.04	2.13	2.23	2.33	2.43	2.50	2.58	49.8
TREND 85	1.65	1.74	1.83	1.93	2.03	2.14	2.25	2.37	2.49	2.62	2.75	2.89	3.04	68.1
AEO92						1.46	1.55	1.62	1.67	1.75	1.83	1.91	1.95	30.1
TREND 90						1.46	1.49	1.52	1.56	1.59	1.62	1.66	1.69	17.8
Average Electricity Prices (Nominal Cents per Kilowatthour)														
Actual	6.40	6.40	6.40	6.40	6.50	6.60	6.70	6.80	6.90	6.90	6.90	6.90	6.90	
AEO86	6.40	6.67	6.89	7.05	7.20	7.38	7.50	7.46	7.47	7.63	7.86	8.07	8.33	11.4
TREND 85	6.40	6.81	7.26	7.73	8.23	8.77	9.34	9.95	10.60	11.29	12.03	12.82	13.66	46.8
AEO92						6.60	7.01	7.20	7.34	7.53	7.69	7.81	7.96	9.4
TREND 90						6.60	6.82	7.04	7.27	7.50	7.73	7.97	8.21	9.4
Gross Domestic Product (Nominal Billion Dollars)														
Actual	4,181	4,422	4,692	5,050	5,439	5,744	5,917	6,244	6,558	6,947	7,265	7,636	8,080	
AEO86	4,181	4,203	4,434	4,741	5,015	5,371	5,795	6,244	6,726	7,270	7,875	8,524	9,226	6.2
TREND 85	4,181	4,562	4,979	5,434	5,931	6,475	7,068	7,717	8,426	9,201	10,048	10,973	11,983	22.7
AEO92						5,744	5,648	5,992	6,346	6,710	7,115	7,530	7,968	2.9
TREND 90						5,744	6,171	6,629	7,120	7,646	8,211	8,816	9,464	10.7

AEO = Annual Energy Outlook.

Btu = British thermal unit.

Notes: Total energy consumption includes nonelectric renewables. TREND 85 is the result of a simple trend analysis, or regression, in which the one independent variable is the energy term lagged one year and the last historical year is 1985. TREND 90 is the same, with 1990 as the last historical year.

Sources: **Actual Values:** Coal Prices—Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(98/05) (Washington, DC, May 1998). Gross Domestic Product, 1985-1996—Council of Economic Advisors, *Economic Report of the President* (Washington, DC, February 1998). Gross Domestic Product, 1997—U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business* (Washington, DC, April 1998). All Other Values—EIA, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** EIA, *Annual Energy Outlook 1982*, DOE/EIA-0383(82) (Washington, DC, April 1983), and *Annual Energy Outlook 1992*, DOE/EIA-0383(92) (Washington, DC, January 1992).

Appendix A

Total Energy Consumption (TE)

TREND 85

TE = A + B*TE(-1)		
Constant	2,867,989	
Std Err of Y Est	1,873,682	
R Squared	0.9864	
No. of Observations	36	<= Historical Data = 1950 - 1985
Degrees of Freedoms	34	
	TE(-1)	
X Coefficient(s)	0.9706	
Std Err of Coef.	0.0196	
T-Stat	49.6079	

YEAR	**TE**	**TE(-1)**	**TE=A+B*TE(-1)**
1949	30,456,751		
1950	33,077,781	30,456,751	
1951	35,466,822	33,077,781	
1984	74,144,006	70,524,724	
1985	73,980,278	74,144,006	
1986			74,670,403
1987			75,340,213
1988			75,990,304
1989			76,621,257
1990			77,233,636
1991			77,827,988
1992			78,404,842
1993			78,964,715
1994			79,508,107
1995			80,035,501
1996			80,547,371
1997			81,044,171

TREND 90

TE = A + B*TE(-1)		
Constant	2,318,977	
Std Err of Y	1,848,612	
R Squared	0.9878	
No. of Observations	41	<=Historical Data = 1950 - 1990
Degrees of Freedom	39	
	TE(-1)	
X Coefficient	0.9828	
Std Err of Co	0.0175	
T-Stat	56.1409	

YEAR	**TE**	**TE(-1)**	**TE=A+B*TE(-1)**
1949	30,456,751		
1950	33,077,781	30,456,751	
1951	35,466,822	33,077,781	
1989	81,320,610	80,217,739	
1990	84,092,891	81,320,610	
1991			84,969,108
1992			85,830,291
1993			86,676,700
1994			87,508,587
1995			88,326,201
1996			89,129,788
1997			89,919,588

National Energy Modeling System/ *Annual Energy Outlook* Conference Summary

*This paper presents a summary of the National Energy Modeling System/*Annual Energy Outlook *conference held on March 30, 1998. The remarks for each speaker were summarized by the session moderators and are not intended to serve as transcripts of the sessions. The comments and opinions of speakers outside the Energy Information Administration (EIA) are their own and do not necessarily reflect the views of EIA. In some cases, speakers were chosen who have different views from those of EIA in order to have a wider range of opinions in the sessions.*

Introduction

On March 30, 1998, the Office of Integrated Analysis and Forecasting (OIAF), Energy Information Administration (EIA), hosted the sixth annual National Energy Modeling System / *Annual Energy Outlook* conference. These conferences are open to the general public and attract a wide range of participants from other Federal and State government agencies, trade associations, energy industries, private corporations, consulting firms, and academia.

Earlier National Energy Modeling System / *Annual Energy Outlook* conferences concentrated on the initial development of the National Energy Modeling System (NEMS), the underlying model methodologies, and the results of the first *Annual Energy Outlook* developed using NEMS. Recent conferences have focussed less on specific projections and model developments and more on energy issues, key analytical assumptions, and their potential impacts on energy markets.

Keynote Address: A Look at Our Past and Future
Robert Charpentier, ISO New England, Inc.

ISO New England (ISO stands for "independent system operator") is the successor to the New England Power Pool (NEPOOL) as the independent operator of the electric power transmission grid in New England. Along with California, ISO New England is at the vanguard of market-regulated, open access power transmission in the United States.

NEPOOL began operations in November 1971 as a group of investor-owned utilities with integrated regional dispatch, in which individual units were dispatched by central control in a unified least-cost merit order. Member utilities shared the resulting savings from lower generation reserve requirements and from lower generation costs induced by optimal dispatch and better load distribution. NEPOOL had three main objectives: assuring that bulk power is available to meet demand with acceptable levels of reliability, generating bulk power with maximum practical economy consistent with reliability, and benefit-sharing among NEPOOL members. These objectives were achieved by dispatching power as if by one company, in which utilities under-generated or over-generated in comparison with their loads, with surpluses and deficits netted and reconciled. Net users of power paid their avoided costs, providers received their actual costs, and the difference was divided among members.

The Federal Energy Regulatory Commission (FERC) was the prime mover in the shift to ISO New England, through Orders 888 and 889. Order 888 required open access transmission tariffs and the opening of NEPOOL membership to other interested parties. Order 889 required an Open Access Information System (OASIS) in which bids and offers of power services could be posted. In New England, most States and public utility commissions were also moving in the same direction as the FERC.

ISO New England's missions are to ensure reliability, provide open transmission access at fair rates, and act as market power policeman. ISO New England is working with market participants and FERC to develop a market power monitoring plan; however, some mechanism is needed to impose sanctions on market participants if they either withhold resources or disobey instructions. It may be necessary, under unusual circumstances, for ISO New England to order generators to provide power in order to maintain system voltage.

ISO New England has written procedures for six forms of reliability markets and developed sophisticated software to implement trading. ISO New England is also consolidating dispatch control from four satellite bases into one, highly automated central dispatch center, in which dispatch control is accomplished by data communication. The main functional responsibilities are to manage dispatch in accordance with transmission, power, and reliability transactions generated by the markets, and to handle forecasting and billing for transmission services.

Several unresolved transition issues remain: If there is transmission congestion that imposes significant costs, who pays these costs and who collects them? Who pays for generator interconnect to the grid? Who is responsible for product labeling, such as the FERC request for "green power" contracting? What does ISO New England do when it detects the exercise of market power? How robust is the market clearing price? Who is responsible for absorbing externality costs, such as the costs of emissions? Finally, the regulatory need for power has been replaced with the belief that market prices will induce the construction of sufficient generation capacity; however, there is no one who can be ordered to build capacity if the new capacity is not constructed.

Carbon Stabilization: The Road Beyond Kyoto

Moderator: Andy S. Kydes, Energy Information Administration
Rapporteur: Ronald F. Earley, Energy Information Administration

The potential role of man-made carbon dioxide emissions on global warming and recent global warming trends have inspired a plethora of economic analyses of the costs of warming, carbon mitigation, and climate stabilization. The proposed protocol developed in Kyoto, Japan, in December 1997 sets country-specific greenhouse gas reduction targets for all Annex I countries, plus Russia and other states of the former Soviet Union, for the budget period 2008-2012. Key developing countries, including China, India, and Brazil, have announced that they will not abide by any greenhouse gas emissions limits. Most, if not all, projections show that global carbon emissions cannot be stabilized without the participation of key developing countries. Two hotly debated questions are: (a) Why should the U.S. accept severe greenhouse gas emissions targets when no agreement has been reached to restrict emissions from key developing countries? (b) What are the (transition and long-term) costs and benefits for the United States of complying with the Kyoto protocol? This session undertook to frame the issues related to the Kyoto protocol and to provide alternative perspectives on the costs and benefits of complying with the proposed treaty.

Framing the Post-Kyoto Issues

Michael Toman, Resources for the Future

The salient features of the Kyoto agreement are both ambitious and ambiguous. The carbon targets represent significant reductions below business as usual, although the targets are softened by the inclusion of multiple gases and sinks. Although technology optimists believe the agreement is a "free lunch," some economists see doom. The truth lies in between, but the costs are still likely to be significant. To make targets affordable, the agreement provides for various forms of emissions trading within the so-called Annex I countries, but the agreement is seriously ambiguous on how these programs would operate. There is also significant ambiguity on the roles and responsibilities of developing countries, leaving further doubt on how Kyoto and longer-term goals would be realized; therefore, ratification by the United States is uncertain.

Climate change should be examined holistically. A decision framework should think comprehensively and socioeconomically about risks and damage costs; address adaptation; think comprehensively and realistically about control costs; think long-term; think internationally; and address distributional issues. Specifically, the policy should use well-designed economic incentives to limit greenhouse gas emissions; provide opportunities for credible emissions reductions everywhere; pursue opportunities for credible flexibility in the timing of emissions reduction; enhance prospects for technical progress to make stricter emissions limits more affordable; do more to promote effective adaptation; increase understanding of risks; clarify the clean development mechanism; and maximize transparency and opportunities for trading.

The Kyoto Protocol: A Tale of Two (Energy) Sectors

Howard Gruenspecht, Office of Policy and International Affairs, U.S. Department of Energy

The implications of the Kyoto protocol for the natural gas and electric sectors through 2010 are likely to be significant. Notwithstanding the pre-Kyoto conventional wisdom that the protocol itself would provide clear signposts, the outlook remains quite hazy even in a scenario that presumes its ratification. Policies that advance the interests of some parts of the natural gas industry can work against the interests of other industry elements, making it hard to assess "industry-wide" impacts. Until implementation strategies are more clearly delineated, it will be hard to reach any bottom lines regarding the sectoral implications of ratification.

The Department's analyses of electricity restructuring have identified both emissions-increasing and emissions-reducing forces associated with the advent of competition. Examples of the latter include profit incentives for cost-effective efficiency improvements that lower fuel consumption per unit of generation at existing plants; increased market opportunities for efficient new merchant power plants with far better emissions characteristics than the conventional plants they displace; and opportunities for energy-efficiency services bundled with electricity to better meet customer needs. Policies explicitly designed to promote renewable energy or to fund energy-efficiency programs can provide further significant reductions in emissions. When all the relevant factors are considered, competition can be introduced into the electricity sector with confidence that we will "do no harm" to our interest in moving toward, rather than away from, the goals of the Kyoto protocol. While the long-term future of the electricity sector will be significantly impacted by the deliberations regarding the ratification and implementation of the Kyoto protocol, there is no convincing environmental rationale for delaying progress toward greater competition in electricity markets while we await that outcome.

Costs of the Kyoto Agreement

W. David Montgomery,
Charles River Associates

The targets for greenhouse gas emissions set for the United States in the Kyoto agreement will be difficult and costly to achieve. Economic impacts on the United States from any policies sufficient to achieve the limits will be severe and lasting. A different approach could achieve the same climate goals at much lower cost.

The Kyoto agreement calls for the United States to limit its greenhouse gas emissions to 7 percent below 1990 levels by 2010. Based on the EIA forecast of emissions without additional policies, emissions will be 44 percent above the target by 2010. Reducing these emissions will require policies with the force of a carbon tax of $200 per ton or higher. Some Administration analyses estimate lower costs by assuming that new technologies will appear in the market in the next few years and that a global emissions trading system will be put in place. Unfortunately, the serious obstacles to an effective emissions trading system within the Annex I countries and the exclusion of developing countries from carbon emissions limits imply that while energy costs and costs of production will increase dramatically in the United States, they will fall in developing countries. There will be a significant shift of investment in energy-intensive sectors toward developing countries, causing carbon emissions from the developing countries to rise and frustrating the efforts of the industrial countries to lower global emissions.

A sensible long-term strategy for addressing climate change would focus on concentrations in the long term, not near-term emissions targets. It is possible to choose a long-term trajectory with less severe near-term emissions limits that would achieve the same concentration goals at far lower cost than the Kyoto agreement. By delaying emissions reductions until technology is ready and a mechanism for developing country participation is created, it is possible to reduce costs by 90 percent while achieving the same long-term results for the global climate. A more gradual approach would also make it possible to bring developing countries into an international emissions trading system after technologies are available to reduce emissions at low cost.

Kyoto Ratification: A Money-Making Agreement for the United States

Florentin Krause, International Project for Sustainable Energy Paths

Energy models today are seriously flawed in their ability to forecast revolutionary changes in consumer behavior, manufacturer behavior, and technological breakthroughs and costs. Consequently, all such models are likely to overestimate the costs and underestimate the benefits of adhering to the Kyoto protocol. Energy intensity changes in the United States as high as 5 percent per year have been experienced, and there is no good reason why intensity improvements of 3 to 4 percent per year could not be sustained over the long term when all revolutionary changes are fostered.

On the specific point of adjustment costs arising from standards, such costs can be small or large, depending on the manner in which standards are adopted, that is, voluntary versus mandated, timing, and performance versus prescriptive. In any event, adjustment costs are transient and may be dwarfed by net present value benefits in the later years. Adjustment costs may also trigger accelerated innovation that would not have occurred under status quo market structures with high transaction costs, where efficient technologies remain stuck in niche markets and may channel accelerated change into a new, nonincremental direction that otherwise might have been missed. The most efficient set of policies for the United States is a complementary mix of targeted regulatory, incentive, and crosscutting instruments.

Unlocking Caspian Energy Reserves

Moderator: Arthur T. Andersen,
Energy Information Administration

The Caspian region has emerged as one of the most highly prospective regions for oil and gas production in the world. Over the past several years, multinational oil companies have entered into joint venture arrangements to exploit this potential, pledging more than $60 billion in capital investment as of early 1998. Production from the region is currently limited, totaling less than 500,000 barrels a day; however, some people project production in excess of 2 million barrels a day within a decade and two to three times that level by 2020. This conference session undertook to review development issues for the region from three perspectives: What is known about the resource base? What are key elements of enterprise development strategies? What geopolitical issues affect levels of risk to regional development?

Exploration Potential of the Caspian Region

Greg Ulmishek, U.S. Geological Survey

The Caspian regions can be described as a small ocean filled with sediment associated with the delta of three major rivers. In various areas surrounding the Caspian, oil and gas production has a long history; however, although the geology has favored offshore production, little has been accomplished so far. Moreover, only limited drilling and seismic study of the offshore areas have been completed thus far, and only a limited amount of onshore deep drilling has been completed. The drilling that has occurred has revealed several super giant oil and gas fields. Tengiz is the most famous, with reserves currently estimated to range between 6 and 15 billion barrels of oil in place. Three distinct geologic basins underlie the Caspian, which have the following conservative estimates for discoverable reserves: 25 billion barrels of oil and 150 trillion cubic feet of natural gas for the South Caspian basin; 4 to 5 billion barrels of oil for the Mid Caspian basin; and 75 billion barrels of oil for the Northern basin. The U.S. Geological Survey is expected to publish a new report on the region in about 12 to 18 months.

Business Development in the Oil and Gas Industry in the Caspian Region

Joel Busby, Mobil Oil Kazakhstan, Inc.

Discovered reserves in the Caspian regions already total approximately 60 billion barrels of oil, 150 trillion cubic feet of natural gas, and several billion barrels of gas condensate. Reserves identified in Kazakhstan alone rival those for all of Western Europe. However, risks abound in attempting to deliver these reserves into world energy markets. The most formidable risk is transportation, since the Caspian is a landlocked region. Mobil is directly involved with one transportation initiative, a 900-mile pipeline through Russia to the Black Sea. At least three other pipeline systems are under consideration, but each poses economic and political difficulties. The shortest route, through Iran, is currently not viable because of U.S. sanctions policy. The U.S. Government currently supports the construction of a new pipeline with a terminus at Ceyhan, Turkey, an already established oil transshipment port; however, the pipeline would be two times longer than the Iranian route and would involve crossing borders of four countries that currently share varying degrees of mutual antagonism. From a political standpoint, the easiest route is one that would pipe Kazakh oil to China; however, if such a route were developed, it would require a pipeline 3,700 miles long—1,200 miles longer than the longest ever built.

The Great Gamble: Strategic Politics in the Caspian Basin

Geoffrey Kemp, Nixon Center for Peace and Freedom

Because of political uncertainties and risks, current development initiatives in the Caspian region can be likened to a "great gamble." Countries surrounding the Caspian are politically unstable and are subject to a range of internal and external conflicts. New chapters are yet to be written regarding struggles between Armenia and Azerbaijan, Russia and Chechnya, secessionists in Georgia, and Kurds in Turkey. Moreover, Iran's role in the region and its relationship with the United States can have profound effects on profit opportunities associated with Caspian development. Recent signs of thawing in U.S.-Iranian relations could reduce Caspian regional development risks. In addition, it should be recognized that one of the great wild cards in future developments in the Caspian and, more generally, in the Middle East regions is the manner in which China and perhaps India may view their national interests in gaining access to those regions' rich resource potential.

Electricity Restructuring: The States of Play

Moderator: Scott B. Sitzer, Energy Information Administration

The restructuring of the U.S. electricity industry continues to be a widely debated energy issue at both the Federal and State levels. California, New York, and Massachusetts have been leaders in the move to competition; other States—especially those with relatively low electricity prices or access to low-cost resources such as hydropower—have hesitated to open their electricity markets to competition without greater assurance that there will be a measurable consumer benefit. The objective of this session was to provide an overview of the status of State activities with respect to electricity restructuring, from both general and specific points of view. By design, speakers were invited from States with high, average, and low prices of electricity, in order to frame the issues with which each group of States is grappling.

Writing the Rules for Tomorrow's Future

Michael Oldak, Edison Electric Institute

U.S. electricity prices to industrial consumers, in contrast to those of Europe, Japan, and Canada, were essentially flat between 1984 and 1995, while those of our trading partners were rising. Our overall prices have fallen every year since 1982, the peak year for U.S. electricity prices. Increased competition in wholesale power markets has also helped prices to fall, with nearly 600 new marketers and exempt wholesale generators entering the market since passage of the Energy Policy Act of 1992. Nevertheless, the movement toward restructuring has continued strongly, especially from those States with prices higher than the national average. Between now and July 1, 2002, at least 16 States will have begun full competition for generation services at the retail level. The new competitors include representatives from a widely diverse set of industries, including current electricity and gas providers, energy producers, computer companies, and even such seemingly unrelated industries as health and legal services.

There are three important trends in the movement to competition: the structure of the industry, codes of conduct, and tax implications. Structural changes are widely divergent. Some, but not all, States are requiring full or functional unbundling of electricity services and diversity of generation assets. Independent service operators are being required by California, Illinois, New Jersey, and Vermont, while others are recommending or studying the issue. Separate power exchanges are being required by California and New Jersey. A number of States are establishing public benefits programs in the areas of energy efficiency, the environment, and minimum renewable generation—as high as 30 percent in California and Maine. Most States are allowing "prudent, legitimate, verifiable, and unmitigable" stranded costs, under certain conditions and with definite time and rate limits. Examples of stranded costs include power contracts and regulatory assets or commitments such as deferred expenses, some employee benefits, and nuclear decommissioning costs. Most stranded costs must be recovered over a period of 4 to 10 years.

Under competition, each participant has certain roles to play, collectively establishing a code of conduct. The role of the incumbent is to put maximum pressure on prices, to bring all of its efficiencies and economies to bear on the market, and to set the competitive market. The role of the government is to adopt policies that lead to benefits to consumers, not protection from competition for certain competitors. Policymakers must distinguish competitive advantage from market power: the former arises from the ability to produce lower-cost goods and services through efficiency and innovation, while the latter is the ability to restrict output and raise prices above competitive levels, generally from a monopolistic franchise.

The tax implications of restructuring could have negative impacts on city, State, and Federal revenues. New competitors may not pay the same taxes to governments that the former monopolists paid, because of issues related to location or ownership (such as municipal utilities that pay no taxes moving into new territory formerly restricted to investor-owned utilities). In addition, lower prices mean lower tax collections in those jurisdictions. Finding ways to mitigate this potential tax loss is a possible barrier to continued movement toward competition.

Restructuring in California—We're on Our Way

Karen L. Griffin,
California Energy Commission

Restructuring in California begins on April 1, 1998. California has traditionally been a high-cost State for electricity, so it was a prime candidate to become one of the leaders in moving to competition. There was a perception that the regulatory process was not working well in the State, and large customers expressed a strong desire to have direct retail access to electricity services. California's competitive processes include both an independent system operator (ISO), which performs transmission and system dispatch, and a power exchange, which matches customers with suppliers. All investor-owned utilities (IOUs) in the State are required to participate in the restructured system, including Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric; but the public utilities, which comprise 25 percent of the market, are not required to participate. Nevertheless, Los Angeles Water and Power, the largest public utility in the State, is participating in the new competitive structure.

IOUs have been required to divest themselves of their generating facilities, which will now be owned and operated by independent investors within a fully competitive framework. Transmission will be the responsibility of the ISO, and distribution will continue to be performed by utility distribution companies, regulated by the California Public Utility Commission. The new structure has created a number of surprises, including the challenge of retail unbundling, the creation of new businesses that have no direct involvement in physical electricity flow, and the need to coordinate information that was once internal to utilities across many diverse entities.

The transition period for restructuring runs through March 31, 2002, during which time rates for customers of IOUs are frozen at their June 1996 levels. Following this period, rates will go to competitive market levels. Also during this period, customers are required to pay a competitive transition charge to alleviate stranded costs for the affected utilities. As of this time, only about 39,000 customer accounts, or 0.5 percent, out of 10 million total have requested to switch electricity providers.

Early lessons learned from the California experience include: stranded costs must be dealt with; there must be sufficient time to create the competitive infrastructure, consumer expectations must be made realistic; and enormous legal and contractual upheaval must be expected.

Is It Broke?: Restructuring Encounters Resistance in a Low-Cost, Public Power State

K. C. Golden, Washington State Department of Community Trade and Economic Development

The State of Washington has not yet formally restructured its electricity industry, in part because of fears that retail prices could rise in the Northwest under a competitive environment. An important question in the region is the purpose of restructuring, given its already low prices. Much of the State's electricity is delivered by public utilities, which have a generally good reputation for price and service. There is fear that more choice in the marketplace for electricity would be confusing and harmful, rather than beneficial to consumers. Consumers are wary of sorting out choices in a deregulated environment, as they already have been forced to do with telecommunications, airlines, and even traditionally free-market products such as sneakers.

Washington started to think about restructuring as early as 1995, in large part because of the importance of the Bonneville Power Administration (BPA), which wholesales much of the electricity in the State, in addition to direct retailing to large customers. BPA found itself undercut in the wholesale marketplace by the competitive impacts of the Energy Policy Act of 1992 and reacted in a number of ways, including curtailing some residential benefits programs and signing long-term contracts with its direct customers that immunized those customers against paying for stranded costs for the Washington Public Power System's nuclear units. Because of these actions, the region's State governments undertook a "review" of BPA, looking toward what its role would be in the eventually competitive market. This review recommended a subscription system for BPA's power output, separation of generation and transmission services, open retail competition by July 1998, a minimum standard for public benefits, use of renewable generation, and funding of conservation programs under full competition. To date, these recommendations have not yet been implemented.

As noted previously, much of Washington's electricity is provided by public utilities, which are not subject to the State's public utilities commission. Also, there has always been a certain amount of competition between public and private utilities, because there are no specific territory franchises in the State. One of the unique aspects of restructuring in Washington is that stranded costs essentially do not exist and that in fact there are benefits to be derived as prices move to market levels. One of the proposals is to allow large customers to move to market rates, while keeping small customers at the "regulated" level of prices. Because of the perceived risks of changing the current system, the legislature has not yet passed an enabling bill to restructure. Even without enabling legislation, however, competition "without rules" has already begun at the wholesale and large industrial consumer level, and there need to be rules to channel that competition as efficiently as possible.

Electricity Restructuring in Michigan

Jeffrey Pillon, Michigan Public Service Commission

Electricity expenditures in Michigan are more than $6 billion annually, with the State consisting of two separate markets, one each for the Upper Peninsula and the Lower Peninsula. Market power issues have surfaced in Michigan, with its participation in a regional independent service operator being one of the major questions in the debate, particularly because of the need to serve the sparsely populated Upper Peninsula. The current restructuring plan is based on authority granted to the Michigan Public Service Commission and does not require legislation for the basics; however, additional legislative proposals remain under discussion and will be needed for securitization.

Michigan's plan basically splits the generation market into two parts, one for full-service customers and one for direct-access customers. Competitive markets will be phased in over a 4-year period. There will be a rate freeze for full-service customers and no responsibility for "new" transition costs, but stranded costs will be collected through rates. Direct-access customers will be subject to a 0.5-cent-per-kilowatthour charge for transition and stranded costs. By 2002, all customers will have a choice of suppliers.

The main incumbent utilities in Michigan are Detroit Edison and Consumers Energy. Initial estimates of stranded costs are $2.5 billion for Detroit Edison and $1.8 billion for Consumers Energy, based on a market price estimate for generation of 2.9 cents per kilowatthour. The estimated unit cost for stranded cost recovery is about 1.2 cents per kilowatthour. Divestiture is not currently proposed in Michigan. Future challenges include resolution of court challenges, uncertainty about legislation, and the evolution of market processes.

Stimulating Renewables in a Competitive Environment

Moderator: Thomas W. Petersik, Energy Information Administration

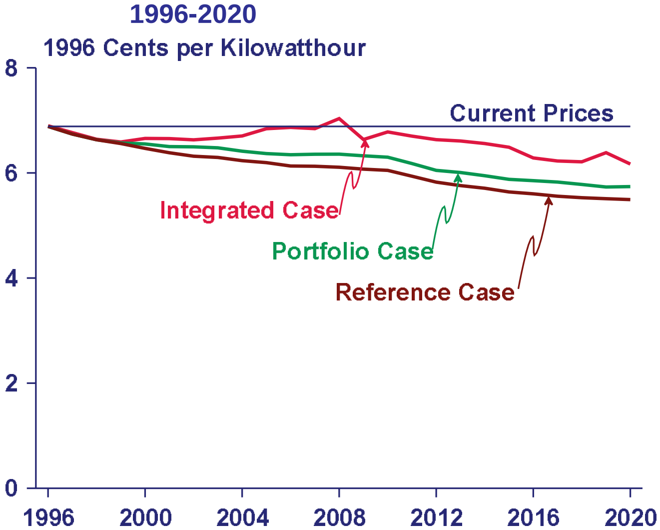
Few energy markets are more uncertain or simultaneously both more hopeful and discouraging than markets for U.S. renewable energy technologies. Costs for some renewable energy technologies have fallen substantially since the 1980s, greatly narrowing the gap with fossil-fueled generation. Growing environmental concerns further heighten public attraction to clean renewable energy sources. At the same time, however, competing fossil-energy technologies, including those using coal and natural gas, have remained highly *competitive by aggressively cutting costs. In addition, the whole technology map is overlaid with changing electricity markets, which are replacing regulated monopolies with freer electricity markets and, thereby, likely reducing protected opportunities for utility investments to advance renewables. This conference session identified and discussed factors and market forces affecting opportunities for renewables: How much will renewable energy technology costs decline and performances improve? What challenges confront renewables? What market changes might affect opportunities for renewable energy growth?*

Analysis of Renewable Portfolio Standard of S. 687

J. Alan Beamon, Energy Information Administration

At the request of Senator James Jeffords of Vermont, EIA analyzed the provisions of Senate Bill 687, the Electric System Public Benefits Protection Act of 1997, calling for the creation of a renewable portfolio standard (RPS) and emissions caps for sulfur dioxide, nitrogen oxide, and carbon dioxide from electricity generation, among other provisions. The RPS set minimum increasing shares of total electricity generation required from qualifying renewables, including biomass and landfill gas, geothermal, solar, and wind, but excluding hydroelectric and incinerated municipal solid waste. Originally targeted at 20 percent by 2020, RPS shares begin at 2.5 percent in 2000 and increase to 10 percent in 2020. EIA also examined integrated cases including the RPS and emissions caps, limiting emissions from electricity generation by 2005 to 3,580,000 tons for sulfur dioxide, 1,914 million tons for carbon dioxide, and 1,660,000 tons for nitrogen oxides.

Figure 1. Electricity Prices in Alternative Cases, 1996-2020



Source: Energy Information Administration (EIA), *Electric Power Annual 1996*, Vol. I, DOE/EIA-0348(96/1) (Washington, DC, August 1997); and EIA, AEO98 National Energy Modeling System, runs RPSBSREG.D120197A, S687RHNU.D120497B, and FLT10REG.D120197B.

Compared to a reference case, the EIA analysis shows imposition of a 10-percent RPS leads to increased electricity generation from biomass and wind and reduced generation from coal and natural gas. Under the RPS, electricity prices by 2020 are 5 percent higher than in the reference case but remain 17 percent below 1996 historical prices in real dollars (Figure 1). Results including both the RPS and emissions caps yield even greater renewables penetration, increasing to 14 percent by 2020, with larger declines in coal and natural gas use and electricity prices 14 percent higher than in the reference case. All RPS conclusions are tempered by uncertainties about the availability of the renewable resources at the required scale and the rate of future cost declines for the renewable energy generating technologies.

Micro-Power: How Electric Industry Restructuring Could Lead to Explosive Growth in Small-Scale Generating Technologies

Christopher Flavin, Worldwatch Institute

Welcome changes in electricity generating technologies offer a dramatically changed U.S. electricity marketplace. Whereas today electricity consumers are generally restricted to purchases from massive, central-station generators operated by large electric utilities transmitting bulk power through transmission and distribution networks, in the near future purchases will increasingly favor small, end-user-located generating units meeting individual building or other consumer electricity needs, due to advances in small-scale generating technologies.

Photovoltaics, wind, and natural-gas-fired microturbines are among the most promising small-scale generating technologies. Technological improvements have significantly lowered costs for all three, in some cases becoming competitive with the delivered price of central-station power. Furthermore, each technology has valuable environmental advantages over traditional coal-fired generating stations. Finally, because these small-scale technologies are still relatively new, further technical advances and economies of scale should continue driving small-scale technology costs further into the competitive range.

Renewable Energy for the Future

Robert T. "Hap" Boyd, Enron Wind Corporation

Markets for renewable energy electricity generating technologies are growing rapidly, both in the United States and in global markets. Markets are increasing and costs are declining. At the same time, all renewables face daunting challenges, not the least of which are their own costs and performance as well as continuing strong competition from traditional fossil-based technologies. In the United States, electricity market deregulation remains a challenge to renewable energy investment.

Each major renewable energy technology enjoys opportunities and faces unique challenges. Generation from biomass and waste, including forest and wood wastes and municipal solid waste, is nearly cost competitive and offers the further substantial benefit of significantly reducing U.S. waste volumes. Its prospects should improve as the values of nonpower benefits increase. Geothermal power, which is growing more rapidly outside the United States, needs substantial cost reductions in order to enjoy expansion at home; however, improvements in drilling and reservoir confirmation should help improve geothermal's competitive position.

Photovoltaics (PV) appear to be offering great promise both domestically and abroad. PV applications are expanding, production continues to increase rapidly, module costs are dropping, and technological improvements are ongoing, both for on-grid applications and for off-grid individual use. PV also enjoys substantial public support. Nevertheless, especially for uses in the United States, PV remains very costly compared with other U.S. central-station generation sources.

Electric power using central station wind energy is also enjoying substantial expansion, especially so outside the United States. International growth, including in Europe and India, remains strong, triggered in part by generally higher electricity prices and also by greater public support for nonfossil alternatives. As wind turbine sizes approach a limit of around 750 kilowatts, additional cost-reducing efficiencies should appear. Wind technologies should succeed where there are concerns about fossil fuels and where electricity prices are higher than in the United States. Deregulation of U.S. electricity markets and stiff competition, however, remain serious concerns to wind-power development.

Fathoming Offshore Oil and Gas
Moderator: James M. Kendell, Energy Information Administration

The deepwater offshore Gulf of Mexico is becoming an increasingly important source of oil and gas supply. During the 1990s the number of deepwater fields with proven reserves has increased by more than 50 percent. In 1996, the deepwater area of the Gulf outer continental shelf contributed 17 percent of total U.S. oil production and 6 percent of total gas production—up from less than 2 percent in 1985. In October 1997 deepwater drilling was at an all-time high, a record 31 rigs. The objectives of this session were to present a new deepwater offshore oil and gas supply submodule for NEMS and to discuss the resources, technology, and costs involved in finding and producing offshore oil and gas.

Improved NEMS Deepwater Gulf of Mexico Oil and Gas Supply Submodule
Michael L. Godec, ICF Kaiser International, Inc.

The previous NEMS offshore submodule was an aggregated econometric representation. The problems with an econometric approach to such a frontier area are the scarcity of historical data and the rapid changes in technology. The new submodule is a disaggregated, field-level representation, based on a set of price/supply curves generated from field size, water depth, gas/oil ratio, economics, drilling technology, and other information. In this submodule deep water is defined as depths greater then 200 meters. Data for 97 deepwater discoveries were collected from the Minerals Management Service (MMS), publications, and private sources. The resulting resource estimates are quite close to those of MMS, although the model is capable of representing alternative views of the size and characteristics of deepwater resources. In addition to price, drilling capacity is a major driver in the new model.

Estimating Undiscovered Hydrocarbon Resources—A Probabilistic Methodology
Pulak K. Ray, Minerals Management Service

MMS estimates undiscovered oil and gas resources with a "play-based" methodology that captures the range of geologic uncertainties. A "play" is a group of pools present in a geologically homogenous unit having similar petrophysical and geochemical characteristics. Prior drilling data, analogous geologic structures, and geophysical data are among the factors considered in established, frontier, and conceptual plays. A standardized discovery process methodology is used in assessing established plays, while a subjective methodology is used to assess the less certain frontier and conceptual plays. The discovery process model is defined by a formal mathematical equation. In the subjective methodology, data on porosity and thickness of the geologic formations are used to create prospect distributions, which are aggregated into pool distributions. These are sampled to create resource estimates. All estimates are inherently subjective, because they are based on a geologist's assumptions.

Offshore Drilling Technology
Rodney W. Eads, Diamond Offshore Drilling, Inc.

Water depths for offshore drilling began to drop rapidly in the 1970s and are expected to reach 8,000 feet later this year. Offshore drilling rigs have evolved from a land-type rig through submersibles, jackups, conventionally moored semisubmersibles, dynamically moored semisubmersibles, and drilling ships.

Utilization and day rates for offshore rigs have increased significantly over the past 10 years, partly because of advanced technology, including three-dimensional seismic, directional drilling, multilateral completion, and subsea completion. Horizontal drilling has allowed producers to extend their drill bits up to 7.5 miles from their rigs. Multilateral completion allows one well bore to tap several reservoirs; this technology is expected to mature within the next 5 years. Subsea completions allow wells to be tied by pipeline to producing platforms up to 20 miles away. The next important technological advance is expected to be multiphase pumping of oil, gas, and water in pipelines on the sea floor.

Electricity Forecasting in a Competitive Market
Moderator: Robert T. Eynon, Energy Information Administration

Restructuring of electricity markets is expected to significantly alter the number and kinds of market participants. This in turn will lead to a variety of new products and services that are not known now. As a result, there are a number of challenging analytic issues that need to be addressed. The purpose of this session was to explore the methods available to assess potential outcomes. The issues to be considered include: How will transmission services be priced? How will ancillary services such as voltage stability be provided? Are services such as reactive power important, and will they affect markets? Will players with market power have an impact on prices? Will investors have incentives to bring on new capacity when it is needed, and how will the reliability of electricity services be affected?

Common Pitfalls and Unresolved Issues in Power Market Price Forecasting
Philip Q Hanser, Brattle/IRI

Issues that determine market outcomes are sensitive to the period of the analysis. For example, weather is an important determinant for short-term considerations, while cost and performance of new generating capacity, economic growth, and environmental regulations become important for longer-term forecasts. There are several pitfalls that analysts need to be aware of when addressing restructuring issues, including the implicit or explicit pricing of generating capacity, the timing and need for new capacity, the mix of capacity, the efficiency of electric generation, and the installed cost of capacity. The price of natural gas is also crucial because it will be the fuel source of the marginal generation unit for many periods of the year.

Policy issues that need to be confronted include determination of whether reserve margins will be set administratively or by the marketplace. Environmental regulations could result in some generating types being no longer economically viable for the marketplace. Changes in cost of production for some generating sources will have no impact on electricity prices if those generation sources are infra-marginal providers. Therefore, competitive markets may have less price variability compared with regulated markets. Available transmission capacity is time sensitive, and, as a result, bidders need to be aware of the premiums necessary to lock in transmission services a month ahead versus an hour ahead. Recovery of capacity costs will occur for all generators whose variable costs of production are below the cost of the marginal source, which is likely to be a gas-fired combustion turbine. When evaluating the value of capacity, it is important not to double count cost recovery associated with capacity payments, ancillary services, etc. Capacity expansion decisions should be based on current market prices. The rapid penetration of natural gas in electricity production suggests that the infrastructure for gas delivery might lag the required need. Because of differences in load shapes, retail price premiums will differ for end users.

Analysts should focus on addressing the correct questions rather than pursuing extreme precision for market determinants. For example, given the wide variation in the projected prices for natural gas, it is better to understand what the impacts of gas prices are than to pursue a precise gas price projection.

A View from the Trenches, Revisited
David J. DeAngelo, PP&L, Inc.

In order to effectively assist in the decisionmaking for strategies to respond to competitive markets, analysts need to rely on economic theory, especially microeconomics. Analysts need to be used and useful in their organizations and should seek out potential users and work interactively with them to meet their needs. Care should be given to problem definition, modeling and forecasting, interpretation of results, and the formulation of strategies. The effects on resource markets need to be addressed in light of restructuring activities. New providers are entering the marketplace and need to be considered. Mergers are also changing the characteristics of electricity markets and will have impacts on other players.

The Impact of the Transmission System on Electricity Markets—A Simulation-Based Approach
Thomas J. Overbye, University of Illinois

Electrical transmission networks will have an impact on electricity markets in a competitive environment. Transmission system operations are complicated by the physical laws of nature, which result in a change in flow everywhere in the system when a change is introduced at a single bus in the network. As a result, it is not possible to control the flow of power directly on the system because electrons do not obey contract paths. Operators need to assure stability of the transmission network in order to prevent blackouts. Transmission operators monitor area control error, which addresses proper loading on tie lines, and provide both real and reactive power in response to customer demands. Real power needs are driven by resistive loads, and reactive power needs are determined by magnetic devices such as motors. Reactive power has losses in delivery that are 10 times greater than those for real power, and generating sources need to be provided close to where the demands are located. Costs for transmission services are invariant for increasing levels of load up to the point where constraints on line limits are reached. Policies for transmission planning in restructured electricity markets are currently ill-defined. The financing of transmission lines is particularly problematic. Issues related to power flows beyond the jurisdiction of a given independent system operator have yet to be addressed.

Transportation Issues: Fuel Economy in a Carbon-Constrained World

Moderator: David Chien, Energy Information Administration

Low fuel prices combined with rising income levels have led to flat or slightly declining new light-duty vehicle (LDV) fuel economy over the past few years. Consumers have shifted their preferences toward larger vehicles with higher performance levels and toward light trucks, especially sport utility vehicles. Consumers are also willing to trade fuel economy for safety, a major marketing point for sport utility vehicles. Foreign competition, in markets with fuel prices three to four times higher than domestic prices, has been cited as a reason for domestic manufacturers to develop advanced technologies. In addition, environmental issues are used to justify policies favorable to alternative-fuel vehicles (AFVs) and advanced technologies; however, conventional vehicles have reduced their vehicle emissions, creating an additional challenge for AFVs. AFVs have been encouraged by a variety of policies; however, it is important to ask whether public policy is the route to higher fuel economy.

Kyoto Dreams vs. Market Realities: Prospect for Big Boost in LDV Fuel Economy

Steve Plotkin, Argonne National Laboratory

We are currently at the brink of a revolutionary technological breakthrough in fuel economy as compared to the past, which had a more incremental approach to fuel efficiency. The most promising technologies are hybrids, fuel cells, lightweight materials, direct injection technology, advanced aerodynamics, and continuously variable transmissions. Even if these technologies were available today at cost-effective prices, significant market penetration would take time because of the slow turnover in the vehicle stock.

The market reality is that fuel economy is not valued, and AFVs must compete against gasoline vehicles with improved emissions. Consumers are currently willing to trade fuel economy for acceleration, structural stiffness, interior space, and luxury equipment such as 4-wheel drive. Safety and emission equipment also tends to work against fuel economy improvements. If consumers were willing to accept 1984 weight and performance levels today, new car fuel economy would be 4 to 5 miles per gallon higher than it now is. The consumer shift from cars toward light trucks is another trend that has reduced fuel economy.

U.S. market conditions will not provide much incentive for higher fuel economy. Although the goals of the Partnership for a New Generation of Vehicles are laudable, achieving vehicle costs similar to gasoline vehicles is not likely. EIA should have scenarios such as technological optimism and technological pessimism in combination with fuel price changes. Although the *Annual Energy Outlook 1998* shows the share of light trucks as nearly 46 percent of light-duty vehicles sales, a share in excess of 50 percent by the turn of the century should be considered.

Forecasting Fuel Economy: Do We Need a New Methodology?

David Greene, Oak Ridge National Laboratory

Prices and economic growth will have less effect on fuel economy, and the status of technology will likely play a greater role in bringing higher fuel economy to the market. Although EIA has included high and low technology cases, the range in fuel economy is only 2 miles per gallon and should be widened. Fuel economy technologies have penetrated the market, but the NEMS fuel economy module is optimistic in assuming that any technology that can improve fuel economy will penetrate.

NEMS was used in the Five-Lab Study by the national laboratories as the best fuel economy model available; however, NEMS optimizes tradeoffs, assuming perfect markets with perfect information and rational decision-making (although a tradeoff between fuel economy and performance is included). The technological potential is huge, but fuel economy markets are not perfect and will not optimize. Consumers look at cost, reliability, and safety then try to satisfy other attributes, including fuel savings. Fuel savings are highly uncertain, due to uncertainties in on-road fuel economy and fuel costs. The value of fuel savings to the consumer is constant over a wide range of fuel economy improvement. Combining that with manufacturer risk, the end result is sluggish fuel economy improvement.

The impetus for improving fuel economy comes from public goods, such as energy security and environmental and sustainability issues, not from market forces. Technology change is the key, but, because technology change is difficult to predict, fuel economy is difficult to forecast. Future policies could have more of an impact on fuel economy than prices and economic factors, but they are uncertain. EIA should include scenarios with different possible future policies.

The Challenge of Restricting Consumption of Low-Cost, Plentiful Energy

Roberta Nichols, Alternative Fuels Consultant

Technology is the easy part; however, making technologies affordable and bringing them to the market are the real challenges. The greenhouse gas issue has inherent problems as an impetus to fuel economy improvements, because it is a long-term issue with no immediate consequences, gradual change is hard to measure, global cooperation is required, and the knowledge level is uncertain. Customers will need incentives to change, because current fuel prices are leading to increased vehicle-miles traveled, larger vehicles, and higher consumption. U.S. safety regulations also lead to heavier cars. Also, there are diminishing returns to fuel economy improvement with higher levels of fuel economy.

Reformulated gasoline and diesel fuel have reduced the incentive to shift to AFVs in order to improve air quality. A lack of infrastructure remains problematic for some AFVs, such as those using natural gas, which could play a major role but are limited to commercial fleets because of the lack of a refueling infrastructure. Global warming issues will increase interest in biomass fuels and other new energy sources. Among the advanced technologies, fuel cells have the greatest potential for fuel economy improvement. Fuel cells currently can use methanol, hydrogen, or gasoline. Methanol is the best hydrogen carrier because of its high fuel density relative to hydrogen storage. Methanol can also be made from any organic material and costs less than ethanol. Hydrogen has a limited range and lacks a refueling infrastructure. The gasoline reformer has many problems that need improvement, such as cost and complexity of design and operation.

The challenge is to overcome customers' risk aversion, compete against low gasoline prices, and address the problems of advanced technology vehicles, such as higher vehicle costs, expensive or nonexistent infrastructures, uncertain resale values, and unproven reliability. Premature introduction of advanced technologies could be deadly. Market incentives are needed, not mandates, because manufacturers can only sell what consumers want. For now we can utilize more fuel-efficient diesel engines, pursue the goals of the Partnership for a New Generation of Vehicles, develop fuel cell technology, continue production of AFVs, and disseminate factual information that will assist consumers in making informed choices.