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The Comprehensive Electricity Competition Act: A Comparison of Model Results

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Preface

The model comparison analysis described in this report was produced by the Energy Information Administration (EIA), applying the National Energy Modeling System (NEMS) to assumptions specified by the U.S. Department of Energy (DOE), Office of Policy, in its May 1999 publication, *Supporting Analysis for the Comprehensive Electricity Act*, or provided subsequently by the Office of Policy. This report was prepared in response to a request from Secretary of Energy Bill Richardson for EIA to "use the NEMS to evaluate the effects of the Administration's restructuring proposal using the parameter settings and assumptions from the POEMS (Policy Office Electricity Modeling System) analysis."

NEMS is an integrated energy-economy modeling system for U.S. energy markets, developed by the EIA as a policy analysis tool to provide an integrated framework for policymakers to understand the implications of proposed policies and alternative assumptions concerning energy markets. NEMS is used by EIA's Office of Integrated Analysis and Forecasting (OIAF) to produce a reference case and a range of alternative projections for the midterm future, which were published most recently in the *Annual Energy Outlook 1999* (*AEO99*).

The Comprehensive Electricity Competition Act: A Comparison of Model Results was prepared by OIAF, under the direction of Mary J. Hutzler (mary.hutzler@eia.doe.gov, 202-586-2222), Director, Office of Integrated Analysis and Forecasting, and Scott Sitzer (scott.sitzer@eia.doe.gov, 202-586-2308), Director, Coal and Electric Power Division. General questions may also be addressed to Andy S. Kydes (akydes@eia.doe.gov, 202-586-2222), Senior Technical Advisor. Detailed questions about the analysis may be addressed to the following analysts.

Executive Summary, Chapters 1, 2, and 4
Alan Beamon (joseph.beamon@eia.doe.gov, 202-586-2025)

Chapter 3
Pete Whitman (pete.whitman@eia.doe.gov, 202-586-1940)

General Modeling and Analysis
Laura Church (laura.church@eia.doe.gov, 202-586-1494)
Jeff Jones (jeffrey.jones@eia.doe.gov, 202-586-2038)

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Executive Summary

On April 15, 1999, Secretary of Energy Bill Richardson forwarded the Administration's proposed Comprehensive Electricity Competition Act (CECA) to the U.S. Congress. The purpose of the CECA is to provide a framework for the restructuring of the U.S. electricity industry. After the CECA was forwarded to Congress, the U.S. Department of Energy (DOE), Office of Policy, released its *Supporting Analysis for the Comprehensive Electricity Competition Act*. That report analyzed the impact of CECA using the Policy Office Electricity Modeling System (POEMS), a computer model of the U.S. energy system.[1] The Secretary then asked the Energy Information Administration (EIA) to replicate the analysis reported in the DOE's *Supporting Analysis*, using the National Energy Modeling System (NEMS), and to compare the results with those from POEMS.

This report provides a discussion of the differences between POEMS and NEMS. In the comparative analysis described here, the modeling assumptions documented in DOE's *Supporting Analysis* were used with NEMS to prepare a noncompetitive case (the CECA Reference case) and a competitive case (the CECA Competitive case). The two NEMS cases were intended to parallel the cases prepared by the Office of Policy.

Comparison of Methodology

In many ways NEMS and POEMS are similar tools. POEMS has adopted all the NEMS modules with the exception of electricity. Even in the case of electricity, some of the models' components are the same. The key differences between the electricity modules are in their regionality and the methodologies used to calculate competitive prices and regional capacity reserve margins. The POEMS electricity component operates with regions approximating the electric Power Control Areas in the United States, a total of 114 regions. The NEMS electricity module, on the other hand, operates at regions based on the North American Electricity Reliability Councils, a total of 13 regions.

Both models base their competitive prices for generation services primarily on what economists refer to as the marginal cost of power—the short run operating costs of the last plant dispatched during each time period.[2,3] To this cost POEMS adds a charge if needed to ensure that new plants recover their investment costs. NEMS adds a reliability price adjustment to reflect the value of reserve capacity.[4] In both models, it is assumed that power from Federal and State facilities will continue be to priced at the average cost of service. Reserve margins are input assumptions to POEMS, while NEMS solves for reserve margins internally by balancing the cost and additional reliability that comes with adding a new plant against the value that consumers place on reliability.

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[1]U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

[2]POEMS actually uses the short-run operating costs of the first plant not dispatched. This approach is what is referred to as a second price auction.

[3]In both NEMS and POEMS it is assumed that over typical operating ranges the heatrates (thermal efficiencies) of plants are constant. In addition, it is assumed that at any given point in time plants are dispatched in merit order (from least cost to highest cost) until the demand for electricity is met. With these assumptions, marginal costs can be defined as the change in total cost associated with the last plant utilized at any point in time.

[4]The competitive pricing algorithms used by POEMS and NEMS are explained in more detail in Chapter 3.

Comparison of Key Results

The key result of this analysis is that, despite model differences, NEMS and POEMS produce similar results when using the same assumptions (Table ES1). The NEMS and POEMS results for electricity sales, carbon emissions from the electricity sector, and electricity prices are similar. The difference in the CECA Reference cases produced by NEMS and POEMS in 2010 are about 0.5 percent for electricity sales and 1.1 and 0.5 percent for carbon emissions and electricity prices, respectively. In the CECA Competitive cases NEMS and POEMS produce electricity sales and electricity prices which differ by 0.2 percent and 0.7 percent, respectively, in 2010. While the electricity sales figures are closest they are not identical; although NEMS and POEMS use the same demand models, the difference in regional detail between the models can result in small differences. The NEMS CECA Competitive case prices are slightly higher than the comparable values from POEMS because NEMS includes sales taxes for generation services in the competitive price, but POEMS does not.

Table ES1. Comparison of NEMS and POEMS Electricity Sector Results for Two Cases, 2000-2015

Estimate	1997	2000		2005		2010		2015	
		POEMS	NEMS	POEMS	NEMS	POEMS	NEMS	POEMS	NEMS
		CECA Reference Case Results for Electricity							
Sales (Billion Kilowatthours)	3,129	3,261	3,274	3,512	3,508	3,794	3,776	4,065	4,057
Carbon Emissions (Million Metric Tons)	532	566	595	608	623	648	655	710	711
Electricity Price (Mills per Kilowatthour)	69.1	66.5	65.6	65.8	65.6	63.3	63.6	60.0	59.1
		CECA Competitive Case Results for Electricity							
Sales (Billion Kilowatthours)	3,129	3,330	3,312	3,515	3,514	3,706	3,714	3,954	3,956
Carbon Emissions (Million Metric Tons)	532	575	600	575	597	587	602	646	662
Electricity Price (Mills per Kilowatthour)	69.1	56.5	59.9	57.8	58.2	54.7	55.1	52.2	52.5
		Differences Between Competitive and Reference Cases							
Sales (Billion Kilowatthours)	NA	69	38	3	6	-88	-62	-111	-101
Carbon Emissions (Million Metric Tons)	NA	9	5	-33	-26	-61	-53	-64	-49
Electricity Price (Mills per Kilowatthour)	NA	-10.0	-5.7	-8.0	-7.4	-8.6	-8.5	-7.8	-6.6

NA = not applicable.
Sources: **1997:** Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1999). **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999). **NEMS:** National Energy Modeling System runs CECABAS1.D082799A (CECA Reference) and CECACMP2.D082899A (CECA Competitive).

The CECA Competitive case results for carbon emissions in 2010 differ by approximately 2.5 percent (15 million metric tons) between NEMS and POEMS. However, the 2010 differences in carbon emissions between the CECA Reference and Competitive cases are similar—61 million metric tons lower in POEMS and 53 million metric tons lower in NEMS. The difference in carbon emissions appears to result partially from the difference in electricity losses in the two electricity models. NEMS, using transmission and distribution loss factors calibrated to 1997 data, uses slightly more electricity generation than POEMS to meet a similar level of demand.[5] The loss factors used in POEMS appear to be about 1.0 to 1.5 percentage points lower by 2010 than those used in NEMS.

Comparison of Renewable Portfolio Standard Results

The similarity in the model results extends to their response to the renewable incentives included in CECA Competitive case in the *Supporting Analysis*. The *Supporting Analysis* assumed that new wind and biomass plants built between 2000 and 2015 would receive a 1.5-cent tax credit for each kilowatthour produced over the first 10 years of their operation. A 1.0 cent per kilowatthour incentive was assumed for coal plants co-firing biomass. In addition, the 7.5-percent renewable portfolio standard (RPS) for nonhydroelectric renewables in CECA is included in the CECA Competitive cases. In both NEMS and POEMS, the construction of new wind plants and the increased use of biomass in coal plants provide most of the increase in renewable generation stimulated by these incentives. In NEMS, however, the renewable credit price reaches the 1.5 cent per kilowatthour cap set by CECA before the 7.5-percent share is reached. In 2010, both the NEMS and POEMS competitive cases reach a nonhydroelectric renewable share of 7.0 percent, but in 2015 the shares are 7.1 percent in the NEMS case and 7.7 percent in the POEMS case.[6]

Regional Comparison of Results

At the NEMS electricity region level, the results are generally similar. The largest differences occur in the western regions, where NEMS and POEMS show different electricity trade patterns. NEMS shows more electricity generation in the Northwest (16 percent) than does POEMS (and ships the power to California). As in the *Supporting Analysis*, at the NEMS region level, nearly all regions show lower prices in the NEMS CECA Competitive case than in the NEMS CECA Reference case in 2010. The only region where this does not occur in NEMS is the Northwest, where the competitive price is 1.4 percent higher than the reference price in 2010.

Summary

The overall similarity of the NEMS and POEMS projections under a common set of assumptions demonstrates that DOE's *Supporting Analysis* results are not dependent on model features. This study did not evaluate the assumptions used in developing the *Supporting Analysis*. The results using either of the models would be different if other assumptions regarding the impacts of competition on the operation and performance of the electricity supply sector were used.

The differences between results for the CECA Reference and CECA Competitive cases are nearly the same in the two models. Using NEMS, in 2010, CECA Competitive case electricity prices are 13 percent lower, renewable generation

[5]The loss factors used in *AEO99*, based on earlier data, were slightly higher.
[6]The POEMS results in 2015 exceed the required 7.5-percent share because the *Supporting Analysis* assumed that green power programs would stimulate renewable development (0.3 percent of sales) independent of the RPS requirement. NEMS does not include this assumption.

is 35 percent higher, and carbon emissions from the electricity sector are 7 percent lower than in the CECA Reference case. Using POEMS, the corresponding differences between the two cases in 2010 are 14 percent lower electricity prices, 38 percent higher renewable generation, and 9 percent lower carbon emissions from the electricity sector.

1. Introduction

On April 15, 1999, Secretary of Energy Bill Richardson forwarded the Administration's proposed Comprehensive Electricity Competition Act (CECA) to the U.S. Congress. The purpose of the CECA is to provide a framework for the restructuring of the U.S. electricity industry. Although electricity restructuring has proceeded steadily over the past 5 years, legislative and regulatory activities have occurred mainly at the State level and at the Federal Energy Regulatory Commission (FERC), which has taken steps to open access to transmission lines that are owned primarily by large electric utilities. The U.S. Department of Energy (DOE) believes that national legislation is necessary because electricity regularly flows across State lines and is vital to the overall health of the U.S. economy. The major provisions of the CECA are intended to:

- Clarify that States have the authority to order retail competition; that FERC has the authority to require public utilities to provide open access transmission services and permit recovery of stranded costs; that FERC's jurisdiction over transmission services is extended to include municipal and other publicly owned utilities and cooperatives, and that Federal Power Authorities and Administrations have the right to recover stranded costs where necessary.

- Give FERC the authority to require the establishment and operation of independent regional system operators to resolve market power problems.

- Establish a Federal Public Benefits Fund that supports low-income customer programs, energy conservation and energy efficiency programs, consumer education, and the development of emerging electricity generation technologies.

- Create a grant program available to rural and remote customers.

- Establish a Federal Renewable Portfolio Standard (RPS) to guarantee that a minimum level of renewable generation is developed in the United States.

- Allow "net metering" (the sale of electricity by a consumer to a supplier) by consumers having small, on-site renewable energy generating facilities.

- Provide a tax credit for certain high-efficiency combined heat and power systems placed in service between 2000 and 2002. In addition, the tax depreciation period for these facilities is shortened, and nationwide interconnection standards for them are to be developed.

- Provide consumers with the information they need to choose an electricity supplier and allow them to join together (aggregate) when bargaining for power.

Following CECA's transmittal to Congress, DOE issued its *Supporting Analysis for the Comprehensive Electricity Competition Act* (hereafter referred to as the *Supporting Analysis*) in May 1999.[1] That document analyzed the proposed legislation in terms of its impact on electricity prices, demand, capacity, generation, and the environment. It also addressed the issues of stranded costs and the impacts of restructuring on rural America. In preparing the report, DOE's Office of Policy used POEMS (the Policy Office Electricity Modeling System) to project the impacts of the CECA on electricity markets through 2015 in comparison with a case in which electricity was assumed to be fully regulated.

On June 24, 1999, Secretary Richardson requested that the Energy Information Administration (EIA) incorporate the parameters and assumptions from DOE's analysis into the National Energy Modeling System (NEMS) and compare its results with those produced by POEMS.[2] POEMS and NEMS are similar modeling systems. Both represent the supply and demand for energy in the United States. The models have different electricity sector modules, but in other respects they are the same. The request was made by the Secretary "to provide further evidence regarding the benefits of competition under the Administration's plan." The Secretary also requested that the resulting report include a comparison of the POEMS and NEMS electricity modules.

As requested by the Secretary, this report compares the results of NEMS and POEMS using the assumptions from the *Supporting Analysis* together with more detailed assumptions provided by DOE's Office of Policy.[3] The report also provides a discussion of the differences between NEMS and POEMS. This report is a comparison of projected market results in NEMS and POEMS when both use the same assumptions. It does not evaluate the assumptions used in developing the *Supporting Analysis*. As discussed in the *Supporting Analysis*, many of the activities being undertaken by the States and FERC would continue with or without CECA. Therefore, this analysis does not address the impacts of CECA alone.

The structure of the report is as follows: Chapter 2 discusses the assumptions from DOE's *Supporting Analysis* that were incorporated into NEMS; Chapter 3 compares NEMS and POEMS; and Chapter 4 compares the results from NEMS with those from POEMS. The appendixes provide regional tables, more detailed assumption information, discussion of the algorithmic changes made to the NEMS electricity module since it was used to prepare the projections reported in EIA's *Annual Energy Outlook 1999*, and copies of the letters requesting the study and providing supplemental assumption information.[4]

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[1]U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

[2]Memorandum to Jay Hakes from Secretary Richardson. See Appendix E for full text.

[3]Memorandum to Mary Hutzler from Howard Gruenspecht. See Appendix E for full text.

[4]The *Supporting Analysis* provided the major changes to the *AEO99* assumptions to incorporate competition. However, during the preparation of comparison runs in this analysis, other assumptions were noted that affected the results and these were documented in the memorandum of August 18, 1999, in Appendix E.

2. Modeling Assumptions

The purpose of this study is to compare NEMS results to those produced by POEMS when both modeling systems use the assumptions outlined in the *Supporting Analysis*. As in the *Supporting Analysis*, two cases have been prepared. The first, referred to as the CECA Reference case, represents an electricity market that is fully regulated. The second, referred to as the CECA Competitive case, represents an electricity market in which the generation service sector of the industry is fully competitive.

This analysis used the version of NEMS used for EIA's *Annual Energy Outlook 1999* (*AEO99*),[5] with the exception of modeling changes and minor data updates in portions of the electricity module. Enhancements to the NEMS electricity module that have been made since *AEO99* are discussed in Appendix D. All of the assumption and modeling changes (other than the new dispatching algorithm described in Appendix D) to the *AEO99* were made to incorporate the assumptions for the CECA Reference and CECA Competitive cases documented in the *Supporting Analysis*, or provided to EIA by the DOE Office of Policy (see Appendix E). Where the structure of the NEMS and POEMS electricity modules differ, assumptions were incorporated to obtain a similar impact within the NEMS framework.[6] The key changes from the assumptions used in the *AEO99* fall into the following areas.[7]

Pricing of Electricity Generation Services

In the CECA Reference case it is assumed that all electricity services will continue to be provided as a single commodity—i.e., bundled service that includes transmission, distribution, and generation services. Consumers will continue to purchase electricity from their current electric utilities, and electricity prices will continue to be based on the average cost of service. Because some States have already moved to competitive electricity pricing, this case does not represent the current situation in all parts of the country. It more closely represents the pricing of electricity up to the mid-1990s.

In the CECA Competitive case it is assumed that the major electricity services—transmission, distribution, and generation—will be unbundled and priced separately. Transmission and distribution service prices will continue to be based on the average cost of service, including the recovery of investments in new equipment to serve customers. Prices for generation services are assumed to be set competitively, based on marginal costs. In other words, the price of power is assumed to be based on the variable operating costs (what economists refer to as marginal costs) of the last plant used to meet demand during a given time period. This means that consumers will pay their local utilities to deliver the power to them, but they will be able shop around for a power supplier of their choice. Competitive generation pricing is assumed to begin in 2000 in the CECA Competitive case with a transition period to allow for

[5]Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998). More detailed information on the National Energy Modeling System and the assumptions used in the *AEO* can be found online at http://www.eia.doe.gov/oiaf/aeo.html.

[6]For discussion of the major modeling differences between NEMS and POEMS see Chapter 3.

[7]Specific values for the assumptions discussed in this section are given in Appendix C.

the recovery of stranded costs. The differences in the algorithms used by NEMS and POEMS for estimating competitive prices are discussed in the following chapter.

One exception to competitive pricing of generation in the CECA Competitive case is power from Federal and State utilities. The *Supporting Analysis* assumed that without changes in current rules and regulations this power would continue to be priced on the basis of average cost of service. To simulate this in regions with a significant amount of Federal and State electricity generation, the price is calculated as the weighted average of the average cost-of-service price and the competitive price. The weights are the percentage of regional generation from State and Federal facilities.

Recovery of Stranded Costs

In the CECA Reference case, which assumes full cost-of-service regulation, electricity suppliers are assumed to recover all the costs associated with the production and delivery of electricity to their customers. The movement to competitive generation markets in the CECA Competitive case could reduce prices such that some investments that were previously made to serve customers' demand for electricity would no longer be recoverable under the conditions of a competitive market. When this occurs, these costs, referred to as stranded costs, are assumed to be recovered, as they were in the *Supporting Analysis*, through a nonbypassable "wires charge" (a surcharge on transmission and distribution services) over a 10-year period.[8] In other words, a fee is added to each kilowatthour of power sold to recover these costs over 10 years. This fee is similar to the competitive transition fee now included in Pennsylvania electricity prices.

The treatment of negative stranded costs (which occur for utilities whose average costs are below the competitive power prices) varies by utility type. Essentially it is assumed that utilities and their customers will negotiate the allocation of negative stranded costs between ratepayers and shareholders. In the case of municipal and cooperative utilities, negative stranded costs are assumed to be returned to the customers who own those utilities. For investor-owned utilities it is assumed that 25 percent of the surplus is returned to customers. Because NEMS treats each region as a single utility, it does not have sufficient accounting detail to break out utilities which might have negative stranded costs, nor is it able to identify stranded costs associated with regulatory assets and nuclear decommissioning costs. In the *Supporting Analysis*, regulatory asset and nuclear decommissioning costs are assumed to continue to be recovered as they have been in a regulated environment. As a result, the values for stranded costs from the POEMS *Supporting Analysis* were input to NEMS in the CECA Competitive case.

Renewable Power Incentives

In the CECA Competitive case, new renewable power plants (excluding hydroelectric plants and fossil-derived municipal solid waste facilities[9]) are eligible to receive two types of incentives. All new wind and biomass plants brought on between 2000 and 2015 receive a 1.5 cent per kilowatthour production tax credit for all the power they

[8]The stranded costs incorporated in this analysis were provided by DOE's Office of Policy, which prepared the analysis of CECA. Aggregate estimates of net stranded costs calculated in NEMS are similar to those calculated in POEMS. As specified in the *Supporting Analysis*, the recovery of additional stranded costs, including regulatory assets and nuclear decommissioning costs, extends beyond 10 years.

[9]Sixty-one percent of the generation from municipal solid waste facilities is estimated to come from biomass sources.

produce during the first 10 years of their operation.[10] In addition, a 1.0 cent per kilowatthour production tax credit is provided for electricity produced from coal plants using biomass between 2000 and 2015. In the case of co-firing, it is assumed that coal plants can use up to 5 percent biomass fuel without investments to upgrade the plant.

The 5-percent maximum share is phased in between 2000 and 2005 to allow time for the industry to adjust to meet the increased demand for biomass co-firing. It could take several years for the biomass residue supply industry to meet the growing demand. The 5-percent maximum share is higher than the 2.66-percent maximum share used in EIA's analysis of the Climate Change Technology Initiative (CCTI).[11] The share used in the CCTI analysis was limited because the high costs of biomass transportation made it unreasonable to expect it to be transported across State lines or to attempt to collect crop residues for co-firing in coal plants. However, the renewable incentives included in CECA are considered likely to extend the economic range for transporting biomass.

In addition, the CECA Competitive case includes a renewable portfolio standard (RPS) requiring that 7.5 percent of total electricity sales be generated by renewable power plants by 2010. Under this provision, retail electricity sellers would have to hold 7.5 credits for each 100 kilowatthours of electricity sold. Credits would be issued to the facilities generating qualifying renewable power. The credits could be held for future use or sold to retail electricity sellers so that they can meet the RPS requirement. The maximum premium for renewable credits is limited under CECA to 1.5 cents per kilowatthour. To limit the cost of the RPS, the government will sell credits at the 1.5-cent price if they are not available in the market for less. If this occurs the required 7.5-percent nonhydroelectric renewable share will not be achieved.

To parallel the assumptions used in the *Supporting Analysis*, 0.3 cents per kilowatthour was added to the cap to represent the success of green power programs anticipated in that analysis.[12] In addition, the supply curves for wind were modified to reduce the cost impact of a rapid buildup in manufacturing of wind capacity (reduction in short-term supply elasticities), which would no longer be reasonable in a case that assumes an RPS.[13] In the *AEO99*, it was assumed that the cost of new wind plants would increase if the amount of capacity built in any year exceeded 20 percent of existing capacity. Costs were assumed to increase by 1 percent for each percent built beyond the 20-percent threshold in a single year. In the CECA Competitive case the threshold was raised to 25 percent, and the rate of increase in price for each percent increase in capacity over 25 percent was lowered to 0.5 percent.

Power Plant Operating Cost and Performance Improvements

In the CECA Reference case, it is assumed that the operating costs and heatrates (thermal efficiencies) of existing plants remain unchanged throughout the projections. Average operating costs and heatrates improve as new, more efficient plants are added to the mix. The heatrates and the operations and maintenance (O&M) costs for existing plants, however, do not change.

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[10]The Administration's Climate Change Technology Initiative, proposed as part of the fiscal year 2000 budget, implements these credits only for plants built between July 1999 and 2004. In this analysis, as they were in the *Supporting Analysis*, these programs are assumed to be extended through 2015. The same extension is also applied to the biomass co-firing credit.

[11]Energy Information Administration, *Analysis of the Climate Change Technology Initiative*, SR / OIAF / 99-01 (Washington, DC, April 1999).

[12]The CECA limits the value of a credit to 1.5 cents per kilowatthour. However, the *Supporting Analysis* prepared by DOE estimated that a certain amount of new renewable generation would be stimulated by green power programs, which allow consumers to purchase electricity from renewable sources for a slightly higher price. To simulate the presumed success of these programs, the *Supporting Analysis* added 0.3 cents per kilowatthour to the 1.5-cent cap used in POEMS, and the RPS was raised to 7.8 percent.

[13]The constraint that limited new wind development to 1 gigawatt per year per region in the *AEO99* was also removed, because the renewable incentives presumably would bring more developers into the market.

In the CECA Competitive case, market competition is assumed to lower nonfuel O&M costs for existing plants over the 1998 to 2010 period. Each existing plant's nonfuel O&M costs are assumed to approach the costs of the best quartile of similar plants over time. Using the *Supporting Analysis* assumptions, the level of improvement varies from 50 to 75 percent (depending on the technology type[14]) of the difference between a plant's current costs and the costs of the top quartile of comparable plants. The *Supporting Analysis* estimated that these assumptions result in 17 percent lower nonfuel O&M costs per kilowatthour generated in the Competitive case than in the Reference case in 2010. The nonfuel O&M cost assumptions used for new plants are also improved from those used in the *AEO99*. Beginning in 2000, as was done in the *Supporting Analysis*, the nonfuel O&M costs of new plants are assumed to equal the targets for existing plants of similar types.

A similar assumption is made in the CECA Competitive case for the heatrates of existing plants. Again, competitive pressures are assumed to motivate power plant operators to find ways to improve the performance of their facilities. Each plant's heatrate improves by 60 percent of the difference between its current level and the level of the best quartile of similar plants. As with the nonfuel O&M cost improvements, the improvement occurs over the 1998 to 2010 time period. For example, on average, coal plant heatrates are assumed to be 5 percent lower by 2010 in the NEMS Competitive case, with the greatest improvement occurring at units that operate with above average heatrates today. Along with the O&M cost and heatrate improvements, steam plants are also assumed to become more reliable in the CECA Competitive case. The availabilities for fossil steam and nuclear plants are assumed to increase to 89 percent, from their assumed 85 percent levels in the CECA Reference case, beginning in 1999.[15]

Other Cost Improvements

The CECA Competitive case also assumes improvements in transmission and distribution service costs, whereas the CECA Reference case assumes no improvement in those costs. As rates are unbundled in the competitive market, regulators are expected to motivate efficiency improvements in the transmission and distribution sectors through the use of incentive-based rate mechanisms—often referred to as performance-based rates. In addition, some portions of the regulated transmission and distribution sectors, such as billing and metering services and transmission line maintenance, may be competitively outsourced. In the CECA Competitive case the total costs for transmission services are assumed to decline by 0.75 percent annually between 2000 and 2010, while the costs of distribution services decline by 1.5 percent annually over the same period. In the CECA Reference case, overhead costs—often referred to as general and administrative (G&A) costs—are assumed to decline by 1 percent annually in real terms between 2000 and 2010. In the CECA Competitive case, the rate of improvement in G&A costs is assumed to be 5 percent annually.[16]

Energy Efficiency and Distributed Power (Cogeneration)

Two changes were made in the CECA Competitive case to represent CECA provisions designed to encourage energy efficiency and promote the development of distributed generation (generation that is located at or near customer

[14]See Appendix C, Table C6, for specific targets.

[15]In the *AEO99* it was assumed that older plants would maintain their current performance; that is, they would not improve their efficiencies or other operating costs.

[16]The *AEO99* assumed a 25-percent reduction (2.8-percent reduction annually) in G&A costs over 10 years. The *AEO99* assumed no improvement in transmission and distribution costs.

sites). To support the goal of increased energy efficiency, the CECA calls for the collection of $3 billion per year for use in a Federal public benefits fund (PBF). This amounts to a fee of approximately 0.1 cent per kilowatthour or about 1.5 percent of the current average price of electricity. The *Supporting Analysis* estimated that, at the national level, the demand for electricity would be reduced by approximately 150 billion kilowatthours by 2010 (165 billion kilowatthours by 2015) because of energy efficiency investments funded by the Federal PBF and the development of integrated energy service companies. The CECA limits the combination of the PBF and any funds collected from the sale of renewable credits to $3 billion per year.

The need for increased central station generating resources is also reduced because of the increased contribution from distributed generators. The CECA calls for the creation of national interconnection standards for distributed power facilities and provides an 8-percent investment tax credit and shorter tax depreciation schedules for new combined heat and power facilities, also known as cogenerators. In the *Supporting Analysis*, cogenerators are assumed to provide roughly 100 billion kilowatthours for sale to the grid by 2010 (136 billion kilowatthours by 2015) beyond what was provided in the CECA Reference case.

Cost of Capital

The riskiness of investments in new generating assets is expected to increase as the market becomes more competitive. Historically the recovery of funds expended to build new power plants was generally assured once the capacity expansion plan was approved by the appropriate regulatory body. In competitive markets there is no such assurance. Changing conditions can force a company to abandon (or write down) a formerly profitable investment at any time. As a result, investors in new power plants will require a higher rate of return than has historically been required in the electricity business. To represent this, the CECA Competitive case incorporates a higher cost of capital than used in the CECA Reference case. The CECA Reference case incorporates a weighted cost of capital of 10.8 percent, while the CECA Competitive case uses a rate of 12.0 percent.

Retirement of Existing Plants

In both the CECA Reference and Competitive cases, plants are assumed to be retired if they are no longer economical to maintain and operate. In other words, once a plant is no longer profitable it is retired. The only exception to this rule is in the treatment of nuclear plants in the CECA Reference case. In this case, the *Supporting Analysis* assumed that nuclear plants would not be retired unless their operating costs exceed the revenues they receive by 7 percent. This differs slightly from the approach used in the *AEO99*. In the *AEO99*, because it was assumed that power plant operators would not make retirement decisions when losses were very small, a 10-percent loss hurdle was incorporated. This was done to represent utilities' resistance to building new capacity when existing capacity was already available—a motivation that should weaken as competitive pressures grow. In addition, because there is considerable uncertainty about future demand and fuel prices, a plant that is unprofitable in one period could turn out to be very profitable in another.

Wholesale Transmission Pricing

In the *Supporting Analysis*, wholesale transmission rates were assumed to be a percentage of the FERC Order 888 *pro forma* tariffs (80 percent of the rates in the Reference case and 50 percent in the Competitive case). The reduction in rates assumed in the *Supporting Analysis* reflects action by transmission owners to discount rates in order to attract more volume. In addition, the Competitive case assumes that transmission charges are zonal rates within Regional Transmission Groups, in contrast to “pancaked” rates (separate rates for each utility system entered) in the Reference case. In both cases, transmission owners recover their full cost of service through a combination of native load and wholesale revenues. NEMS represents the economics of interregional wholesale transactions very differently from POEMS. As a result, it was not possible to directly represent the assumptions from the *Supporting Analysis.* To simulate this effect in the CECA Competitive case, the hurdle rate used for interregional wholesale trades in NEMS was reduced by 50 percent from the value used in the CECA Reference case.

Reserve Margins

In the *Supporting Analysis*, reserve margins were held constant at 8 percent (4 percent in Florida) in both the CECA Reference and Competitive cases as a surrogate for equivalent reliability. In NEMS, reserve margins under competition are endogenously determined by balancing the cost of new capacity against consumers’ willingness to pay to avoid outages. In each region, NEMS uses the demand profile, the size and operating characteristics of available capacity, and an assumption about the value consumers would be willing to pay to avoid losing power (the value of unserved energy) to determine the appropriate reserve margin. For this analysis, it was assumed that the same level of reliability would be maintained in both cases. However, because the performance of existing plants was assumed to improve in the CECA Competitive case (plants are assumed to be out of service for fewer hours), the amount of reserve capacity needed to maintain the same level of reliability is slightly lower. Nationally, the resultant NEMS reserve margins in the CECA Competitive case average near the 8 percent used in the *Supporting Analysis*, but they vary from region to region.

Generation Sector Taxes

The NEMS CECA Competitive case follows the standard competitive market logic that income taxes are not included in the competitive generation price, since maximization of profits prior to the application of income taxes also maximizes profits net of those taxes. Similarly, property taxes, like other fixed annual expenses, are also not included in the estimation of the competitive generation price, although they do enter into decisions affecting unit retirement. On the other hand, taxes that are proportional to the value of generation—gross receipts or sales taxes—are reflected in competitive market prices. The Competitive case in the *Supporting Analysis* did not include an estimate for this latter category in its bid price. In the NEMS CECA Competitive case, FERC Form 1 data were used to estimate regional sales tax rates, which are included in the price of electricity delivered to customers.

Other Differences From the *Annual Energy Outlook 1999* Assumptions

Several other changes were made in the *AEO99* version of NEMS to make it consistent with the POEMS assumptions used in the *Supporting Analysis.* These changes include: changing the fraction of total electricity generation capacity that can be retired annually from 3 to 5 percent; modifying the construction profiles used for new plants; and eliminating the factors used in *AEO99* to calibrate to near-term results.[17] All these changes have the effect of making the model more responsive to the other assumptions made to represent competitive markets. Table 1 summarizes the assumptions used in NEMS for the CECA Reference and Competitive cases.

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[17]These factors are designed to calibrate the first 2 years of NEMS results to the results of the Short-Term Integrated Forecasting System used to produce EIA’s *Short-Term Energy Outlook.*

Table 1. Summary of Assumptions for NEMS Implementation of the CECA Reference and Competitive Cases

Category	CECA Reference	CECA Competitive
Electricity Pricing	Continued cost-of-service pricing in all sectors and States, including those that have already deregulated.	Continued cost-of-service pricing for transmission and distribution services (with cost improvements). Fully competitive pricing for generation services other than Federal facilities and in States that continue cost-of-service pricing.
Stranded Costs	Not applicable.	Generating asset stranded costs recovered through a 10-year wires charge. Negative stranded costs partially returned to consumers.[a] For IOU customers, 25 percent are returned, while 100 percent are returned to municipal and cooperative utility customers.
Renewable Power Incentives	Energy Policy Act of 1992 incentives only (through 2009 for plants brought on line by 1999).	1.5 cent per kilowatthour tax credit for first 10 years of new wind or biomass plant's life. 1.0 cent per kilowatthour for co-firing biomass in coal plants for all years. Renewable portfolio standard (nonhydroelectric) rising to 7.5 percent by 2010 with credit prices capped at 1.5 cents per kilowatthour. 0.3 cents added to 1.5 cent cap to represent impact of green power programs.
Power Plant Operating Cost and Performance Improvements	Overall performance improves as plant mix changes with the addition of new plants and the retirement of older plants. The performance of existing plants remains unchanged.	Existing plant heatrates and operating costs improve toward targets based on performance of best quartile of similar plants. New plants are assumed to reach targets immediately.
Other Cost Improvements	General and administrative expenditures decline by 1 percent annually.	General and administrative expenditures decline by 5 percent annually. Transmission and distribution costs decline by 0.75 percent and 1.5 percent annually, respectively, through 2010.
End-Use Energy Efficiency and Distributed Power	Efficiency improvements represented in *AEO99* NEMS demand models.	Combination of public benefits fund, distributed power programs, and growth in integrated energy service companies reduces the need for grid power by 250 billion kilowatthours by 2010 (300 billion kilowatthours by 2015).
Cost of Capital	Average weighted cost of capital is 10.8 percent.	Average weighted cost of capital is 12.0 percent.
Plant Retirements	Based on the economics of continuing to operate a plant. For nuclear plants, operators do not retire them until costs exceed revenues by at least 7 percent.	Based on the economics of continuing to operate a plant, including nuclear plants.
Interregional Transmission Pricing	Average interregional trade hurdles of 3 mills per kilowatthour.	Hurdle rate for trades between regions is reduced by 50 percent.
Reserve Margins	Set at historical target levels.	Endogenously determined, based on regional load characteristics, plant size and operating characteristics, and an assumed value consumers are willing to pay to avoid losing power. Reserve margins are slightly lower in CECA Competitive case because plants are assumed to perform at higher utilization rates, implying that less backup capacity is needed.

[a]When competitive market prices rise above a utility's cost-of-service-based prices, that utility is said to have negative stranded costs.

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

3. Comparison of POEMS and NEMS

Overview

This chapter compares the modeling approaches of NEMS and POEMS. It describes the general methodologies and points out the most significant differences between the models. With the exception of their electricity modules, NEMS and POEMS share the same components. In addition, they use many of the same data sources, and both are designed to produce annual forecasts through the year 2020. The primary differences lie in the treatment of electricity trade, dispatching, and pricing. A comparison of the two overall systems is given in Table 2, and a comparison of the electricity modeling differences is given in Table 3.

Table 2. Differences Between NEMS and POEMS

Area	NEMS	POEMS
Non-Electricity Modules		
Integration	NEMS Integrating Module	NEMS Integrating Module
Macroeconomic Behavior	NEMS Macro Activity Module	NEMS Macro Activity Module
International Energy	NEMS International Energy Module	NEMS International Energy Module
Residential Energy Demand . . .	NEMS Residential Demand Module	NEMS Residential Demand Module
Commercial Energy Demand . . .	NEMS Commercial Demand Module	NEMS Commercial Demand Module
Industrial Energy Demand	NEMS Industrial Demand Module	NEMS Industrial Demand Module
Transportation Energy Demand .	NEMS Transportation Demand Module	NEMS Transportation Demand Module
Refinery Operations	NEMS Refinery Module	NEMS Refinery Module
Oil and Gas Supply and Demand	NEMS Oil and Gas Supply Module	NEMS Oil and Gas Supply Module
Renewable Fuels	NEMS Renewable Fuels Module	NEMS Renewable Fuels Module
Electricity Module Components		
Capacity Planning	NEMS Electricity Capacity Planning Module	Similar, but with slightly different load representation
Load	NEMS Load and Demand Side Management Module	Similar, but with slightly different load shape representation built up from more disaggregated regions.
Dispatch and Trade	NEMS Electricity Fuel Dispatch Module	TRADELEC™
Pricing	NEMS Electricity Finance and Pricing Module	TRADELEC™

Sources: **NEMS:** National Energy Modeling System Documentation, http://www.eia.doe.gov/bookshelf/docs/html. **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

NEMS was developed by the EIA in 1991-1992 and was first used to produce the *Annual Energy Outlook* in 1993. NEMS consists of four demand modules (residential, commercial, industrial, and transportation), two conversion modules (petroleum and electricity markets), four supply modules (natural gas, oil, coal, and renewable fuels), a macroeconomic feedback module to represent the effects of the energy markets on the overall economy, and a module to represent the interaction between domestic and international energy markets. It produces a general equilibrium solution for energy supply and demand in the United States.

POEMS was developed with a more detailed representation of wholesale electricity markets than is incorporated in NEMS. A more disaggregated electricity module, TRADELEC™, is used in place of the NEMS Electricity Market Module, to allow the examination of alternative assumptions for wholesale electricity markets (Table 2). Some of the data used in TRADELEC™ are not available publicly, and the model is proprietary.

Electricity Module Comparisons

The Electricity Market Module (EMM) is the electricity component of NEMS. The EMM represents the generation, transmission and distribution, and pricing of electricity. The EMM consists of four submodules. The Load and Demand Side Management Module (LDSM) develops load shapes from the annual demand supplied by the other modules. The annual load is represented by 108 time periods, representing different seasons, days, and times of day. The Electricity Capacity Planning (ECP) submodule determines the mix of generation technologies (fossil, nuclear, or renewable) to meet current and expected future demand. It determines capacity additions and retirements by technology and year, based on demand and fuel price expectations and technology cost and performance characteristics. The Electricity Fuel Dispatch (EFD) submodule determines the utilization of power plants given the available capacity, operational and environmental constraints, fuel and nonfuel O&M costs, and the demand for electricity. It determines fuel usage, total operational costs, and trade patterns necessary to meet the demand for electricity. Finally, the Electricity Finance and Pricing (EFP) submodule develops electricity prices and other financial information.

The overall decision process in TRADELEC™ is similar to that in the EMM. The primary differences are in the regional detail and the methodologies used to estimate competitive electricity generation prices. In addition, the accounting of stranded costs and the estimation of reserve margins are somewhat different. These differences are summarized in Table 3.

Regional Detail

The EMM operates at the North American Electricity Reliability Council (NERC) region and subregion level. In total, the EMM represents 13 electricity supply and demand regions. TRADELEC™ operates at the Power Control Area (PCA) level and represents 114 electricity supply and demand regions. Both models include historical data on more than 6,000 electricity generating plants.

The regional representations in both models have advantages and disadvantages. The more disaggregated nature of TRADELEC™ makes it more suited for locational analysis issues, such as adding a new generating plant or transmission line. It also can be used to examine the impacts of alternative transmission pricing schemes—for example, pancaked pricing versus postage stamp pricing. Also, the additional regional detail allows the end-use service loads to be calibrated to PCA-level load data, which are readily available.

Table 3. Comparison of Major Differences Between EMM and TRADELEC™

Area	NEMS	POEMS
Regional Detail	13 regions	114 regions
Pricing Methodology	Marginal energy, taxes, reliability component	Marginal energy, O&M, ancillary services charge
Stranded Costs	Calculated at the EMM region level as the discounted difference of power plant revenues available to meet fixed costs under regulation and competition	Calculated at the utility level by subcomponent—generating plant stranded costs, regulatory asset costs, and nuclear decommissioning costs
Reserve Margins	Endogenous, based on cost of capacity and value of unserved energy	Exogenous
Trade	Aggregated to NERC region	Disaggregated to the power control area level

Sources: **NEMS:** National Energy Modeling System Documentation, http://www.eia.doe.gov/bookshelf/docs/html. **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Both NEMS and POEMS rely on demand models that provide projections of the demand for electricity at the level of the nine Census divisions. NEMS uses fixed factors to allocate these demands to the 13 electricity regions. Similarly, POEMS uses fixed factors to allocate these demands to the 114 regions used in TRADELEC™. The fixed allocation factor assumption is likely to be more reasonable at the 13 region level used in the NEMS than at the 114 region level used in POEMS. The variation in demand growth rates for the smaller POEMS regions is likely to be larger than the variation among the larger NEMS regions. In addition, gathering the data needed (some of which is proprietary) and solving the POEMS are resource intensive. The more aggregate nature of NEMS reduces the data and processing resources required compared to those needed for POEMS. In addition, NEMS, because it has fewer regions to solve, is able to incorporate a more detailed representation of electricity dispatch decisions (108 slices of time versus 72 in POEMS) and make use of publicly available data.

Competitive Pricing

Both the EMM and TRADELEC™ base competitive generation prices on the marginal costs of producing power. However, the derivation of marginal costs is somewhat different in the two models. In TRADELEC™, the marginal costs for each PCA and time period are based on the bid price of the next most expensive plant in the merit order. In other words, when plants place bids to meet a given demand, the winning plants are paid the bid price of the lowest cost plant that did not win—what is often referred to as a second price auction. The bid price for each plant (or plant group) consist of its fuel costs plus a user-specified fraction of its total O&M costs. In the *Supporting Analysis* CECA Competitive case, the fractions of total O&M costs assumed to be included in the bid price differ by plant type. For turbines the fraction of total O&M that is included is 100 percent; for combined-cycle and fossil steam units it is 50 percent; and for nuclear plants it is zero.

TRADELEC™ uses a network algorithm to solve for the flow of power between PCAs. The trading algorithm accommodates both transfer limits between PCAs and the relative marginal costs (including cost of transmission losses and fees) of power between regions to identify the equilibrium price and flows of power. In addition, POEMS adds a charge to ensure that new turbine plants built by the model recover their costs. This charge is derived by calculating the revenue received by new turbines when they are paid the bid prices as described above. If the revenue is insufficient to cover the total costs of the facilities, a charge is added to increase the revenue they receive. This charge is assumed to be paid to both turbine and combined-cycle units, which have quick start capability.

The EMM uses a similar overall approach for the components of price. Marginal costs are calculated for each unit and used in a linear programming formulation for the operations of each of the 13 NERC regions. The EMM does not use a second price auction approach. Instead, the marginal energy price during each time period is set to the sum of the fuel plus variable O&M costs of the last plant dispatched. Trade between regions is constrained by limits on the transmission system. There are no transmission system constraints within regions. Without the representation of intraregional transmission constraints, the opportunity exists to dispatch plants at higher capacity factors than the transmission constraints may allow, thereby understating the cost of electricity generation. As a surrogate for intraregional constraints, maximum utilization rates for coal plants are imposed and phased in over a 5-year period. The EMM solves for the least-cost use of all available generation equipment to meet the demand for electricity, subject to any operational, environmental, and transmission constraints. Interregional trades are adjusted for losses, and a hurdle rate is used to account for the cost of transmitting power between regions.

The EMM uses a methodology different from TRADELEC™ to calculate competitive generation prices. For each time period, the generation component of price consists of: (1) the marginal operating costs, (2) those taxes determined to be marginal costs, and (3) a reliability price adjustment equal to the marginal cost of unserved energy. The marginal operating costs in NEMS include fuel costs and variable O&M costs. However, in NEMS, variable O&M costs for each plant are derived from historical data. On average the variable O&M costs used in NEMS are lower than those used in POEMS. The reliability component represents the value of capacity during periods when capacity is in short supply. In other words, during periods when the demand for power is approaching the total amount of capacity available, the price of electricity will rise to account for the increased value of capacity when shortages are imminent. It is analogous to the capacity charge used in the deregulated electricity market in the United Kingdom.[18] The theoretical underpinning for this approach comes from the work of Schweppe, Caramanis, Tabors, and Bohn.[19]

In both models, prices for transmission and distribution services are assumed to be regulated and are calculated to recover the total costs of these services. In order to parallel the *Supporting Analysis*, a performance-based rate algorithm was incorporated in EMM to reflect the assumed improvements in costs in the CECA Competitive case.

Estimation of Stranded Costs

Because of the more disaggregated regions represented, the asset accounting used in POEMS is done at the single utility level. This allows a more detailed accounting of stranded costs than is possible in NEMS. POEMS treats potential stranded costs resulting from generating assets, regulatory assets, and nuclear decommissioning differently. For generation assets, the net present value of the expected revenue stream of the plant is compared to the book value of the plant. When the discounted revenue stream is less than the book value of the plant, the difference represents stranded costs. On the other hand, when this value is greater than the book value of the plant, negative stranded costs result. It is assumed that all positive stranded costs are recovered over a 10-year period. When there are negative stranded costs, a portion is assumed to be returned to ratepayers. The portion returned varies by utility type. For private utilities 25 percent is assumed to be returned to customers, and for public utilities 100 percent is

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[18]See Appendix A in 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), p. 89.

[19]F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (New York, NY: Kluwer Academic Publishers, 1988).

assumed to be returned to customers. Total regulatory assets and nuclear decommissioning costs that could be stranded in the absence of a fee for their collection are determined exogenously. The fees needed to recover regulatory assets and nuclear decommissioning costs are applied over 25 and 50 years, respectively.

NEMS does not have the ability to calculate stranded costs in as detailed a fashion as does POEMS. NEMS is able to calculate the aggregate difference in revenue available to meet fixed costs under cost-of-service versus competitive pricing. The discounted value of this revenue difference represents the net stranded costs. (Within each NEMS region positive and negative stranded costs are netted against each other.) In this analysis the more detailed estimates from POEMS were used for the calculation of regional electricity prices. For generating assets, net stranded costs are recovered over a 10-year period through a per-kilowatthour fee for all electricity sold. For regulatory assets and nuclear decommissioning costs, net stranded costs are recovered over 25 years and 50 years, respectively.

Estimation of Reserve Margins

Regional capacity reserve margins are an exogenous input in POEMS. For both cases of the *Supporting Analysis*, they were set to 8 percent in all regions and years, except for Florida where they were set to 4 percent. In the NEMS CECA Competitive case, the optimal amount of capacity to be built is determined as a function of the assumed value that consumers place on reliable electricity service, the marginal cost of capacity (assumed to be the cost of a simple combustion turbine), the demand profile, and the mix and performance of existing capacity in each region. In essence, the reserve margin is set at the point that the cost of the marginal unit of capacity is exactly equal to the amount that consumers would be willing to pay for the added reliability it provides.

Although it is complex and requires data that are not readily available (value of unserved energy), the approach used in NEMS takes account of the many factors that can change the amount of reserve capacity needed. For example, if the performance of existing plants improves, less reserve capacity is needed. On the other hand, if consumers invest in increasing amounts of sensitive electronic equipment (computers, telecommunications equipment, etc.), the value they place on reliability is likely to rise, and the need for reserve capacity to ensure that reliability would also increase. In the CECA Competitive case, the optimal reserve margins are lower than in the CECA Reference case because the assumed improvements in the availability of existing plants mitigate the effect of the lower reserve margin.

In addition, in NEMS, having the optimal amount of capacity plays a critical role in setting the market price of electricity. In competitive markets, if developers build too much capacity, the price of electricity may turn out to be too low to make the investments profitable. If, on the other hand, too little capacity is built, there will be periods when prices are high. This behavior is reflected in the reliability price adjustment discussed previously. While this adjustment is near zero during most time periods, it becomes quite high during peak demand periods (over $1.50 per kilowatthour in 2010 in some regions). As electricity markets become more competitive, the price swings caused by this factor will play the dual role of telling consumers when they can save the most money by reducing their electricity consumption, and telling developers when and where it would be profitable to build new capacity.

4. Comparison of Results

Summary

Despite the differences discussed in Chapter 3, the NEMS and POEMS results for electricity sales, carbon emissions from the electricity sector, and electricity prices are similar (Table 4). In the NEMS and POEMS CECA Reference cases in 2010, sales differ by less than 0.5 percent, while carbon emissions and electricity prices differ by 1.1 percent and 0.5 percent, respectively. In the CECA Competitive cases, the 2010 results differ by 0.2 and 0.7 percent for electricity sales and prices, respectively. The CECA Competitive case results for carbon emissions in 2010 differ by approximately 2.5 percent—apparently as a result (at least partially) of the difference in transmission and distribution system losses in the two models. NEMS projects slightly more electricity generation than POEMS to meet a similar demand level. The loss factors used in NEMS have been calibrated to 1997 data, and they appear to be about 1.0 to 1.5 percentage points higher by 2010 than those used in POEMS.

Table 4. Comparison of NEMS and POEMS Electricity Sector Results for Two Cases, 2000-2015

Estimate	1997	2000		2005		2010		2015	
		POEMS	NEMS	POEMS	NEMS	POEMS	NEMS	POEMS	NEMS
		CECA Reference Case Results for Electricity							
Sales (Billion Kilowatthours)	3,129	3,261	3,274	3,512	3,508	3,794	3,776	4,065	4,057
Carbon Emissions (Million Metric Tons)	532	566	595	608	623	648	655	710	711
Electricity Price (Mills per Kilowatthour)	69.1	66.5	65.6	65.8	65.6	63.3	63.6	60.0	59.1
		CECA Competitive Case Results for Electricity							
Sales (Billion Kilowatthours)	3,129	3,330	3,312	3,515	3,514	3,706	3,714	3,954	3,956
Carbon Emissions (Million Metric Tons)	532	575	600	575	597	587	602	646	662
Electricity Price (Mills per Kilowatthour)	69.1	56.5	59.9	57.8	58.2	54.7	55.1	52.2	52.5
		Differences Between Competitive and Reference Cases							
Sales (Billion Kilowatthours)	NA	69	38	3	6	-88	-62	-111	-101
Carbon Emissions (Million Metric Tons)	NA	9	5	-33	-26	-61	-53	-64	-49
Electricity Price (Mills per Kilowatthour)	NA	-10.0	-5.7	-8.0	-7.4	-8.6	-8.5	-7.8	-6.6

NA = not applicable.
Sources: **1997:** Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1999). **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999). **NEMS:** National Energy Modeling System runs CECABAS1.D082799A (CECA Reference) and CECACMP2.D082899A (CECA Competitive).

The difference in transmission and distribution system loss factors can be seen when comparing the total generation values for the two models (Table 5). As shown in Table 5, NEMS projects slightly more electricity generation than POEMS in comparable runs for all years. The difference declines between 2000 and 2010, probably as a result of the assumption in NEMS, based on historical trends, that the percentage losses will decline by approximately 25 percent—about 1.5 percentage points—over the next 20 years.

Table 5. Comparison of NEMS and POEMS Results for Electricity Generation by Fuel in Two Cases, 2000-2015
(Billion Kilowatthours)

Fuel	2000		2005		2010		2015	
	POEMS	NEMS	POEMS	NEMS	POEMS	NEMS	POEMS	NEMS
	CECA Reference Case Results							
Coal	1,841	1,992	1,960	2,037	2,034	2,056	2,207	2,192
Natural Gas	365	372	604	619	930	963	1,193	1,259
Oil	125	84	62	42	37	25	30	21
Hydropower	310	324	311	325	312	325	312	325
Nuclear	678	664	659	640	580	560	427	413
Geothermal	16	14	16	16	18	18	19	20
Refuse	23	24	24	25	26	27	27	28
Wood Steam	10	9	11	11	11	11	11	11
Solar Thermal	1	1	1	1	1	1	1	1
Wind	6	6	7	7	8	8	8	8
Solar Photovoltaic	0	0	0	0	1	1	1	1
Total	**3,375**	**3,489**	**3,655**	**3,724**	**3,957**	**3,994**	**4,237**	**4,278**
	CECA Competitive Case Results							
Coal	1,932	2,037	1,945	2,047	2,012	2,080	2,153	2,213
Natural Gas	330	349	540	505	671	654	913	904
Oil	85	77	25	30	11	18	13	17
Hydropower	310	324	312	325	319	325	322	325
Nuclear	694	673	661	652	581	574	400	413
Geothermal	16	14	18	17	20	20	21	23
Refuse	23	24	24	25	26	27	27	28
Wood Steam	57	24	104	73	106	78	93	55
Solar Thermal	1	1	1	1	1	1	1	1
Wind	6	6	20	37	66	92	117	129
Solar Photovoltaic	0	0	0	0	1	1	1	1
Total	**3,453**	**3,529**	**3,651**	**3,712**	**3,816**	**3,871**	**4,061**	**4,111**

Sources: **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999). **NEMS:** National Energy Modeling System runs CECABAS1.D082799A (CECA Reference) and CECACMP2.D082899A (CECA Competitive).

The models also produce similar results in terms of the differences between results for their respective CECA Reference and Competitive cases. In 2010, electricity sales are 88 billion kilowatthours less in the CECA Competitive case than in the CECA Reference case using POEMS. This compares to 62 billion fewer kilowatthours in the same comparison using NEMS. For carbon emissions the changes between the CECA Reference and Competitive cases are similarly close: 61 million metric tons less in the Competitive case than in the Reference case for POEMS and 53 million metric tons less in the NEMS comparison. For electricity prices the reductions in 2010 are 8.6 mills and 8.5 mills (tenths of cent) per kilowatthour for POEMS and NEMS, respectively. The NEMS CECA Competitive case prices are actually slightly below the comparable POEMS results after adjusting for taxes. The POEMS CECA Competitive case did not include generation sector taxes in the competitive price. Following a review of data filed with the FERC, EIA determined that a portion of the taxes currently paid by generators are gross receipts (sales) taxes and should be included in the competitive price. These taxes are included in the NEMS calculation of competitive electricity prices, accounting for 1.3 mills of the total price in 2010.

Because of State and FERC actions, some of the price change between the CECA Reference and CECA Competitive cases are already occurring. In the *AEO99*, because of State actions, five regions were assumed to move to competitive pricing of generation services—the New York, California, New England, Mid-Atlantic, and Mid-America (Illinois/Wisconsin) regions. As a result, the price of electricity in the *AEO99* in 2010 falls between the prices estimated in the NEMS CECA Reference and NEMS CECA Competitive cases—61.4 mills per kilowatthour in the *AEO99* versus 63.6 in the NEMS CECA Reference case and 55.1 in the NEMS CECA Competitive case.

Generation by Fuel

In the CECA Reference case, both NEMS and POEMS show similar generation patterns over time: natural-gas-fired facilities account for the lion's share of the growth in generation, followed by coal, while nuclear declines and renewables hold fairly steady. NEMS tends to rely more heavily on coal, especially in the early years. By 2010, the CECA Reference case results are very close.

The story in the CECA Competitive cases is similar. NEMS relies a little more on coal in the early years, but by 2010 the shares for most fuels are quite close. By 2015 the only generating fuel with both a large absolute and percentage difference between the NEMS and POEMS CECA Competitive cases is wood steam (biomass). Most of the biomass generation in both models comes from co-firing in coal plants. Studies have shown that most coal plants can burn a small percentage of biomass commingled with coal without major capital expenditures. As a result, in response to the biomass production tax credit and the available RPS credit it was assumed in the CECA Competitive cases that coal plants could burn up to 5 percent biomass if it was economical. In NEMS, however, the 5-percent maximum share is phased in over 5 years, from 1999 to 2004. This is done to represent the time it would take for the biomass supply industry to adjust to supply the needed biomass to coal plants. Because large, economical coal plants play a major role in meeting the demand for electricity in many regions, their owners are cautious about any changes, such as introducing a new fuel source like biomass, that might affect their operation. Before making such a change they would go through an extensive period of testing and evaluation—lining up reliable biomass suppliers, performing test burns in their plant, and making any needed plant modifications.

The phase-in of biomass co-firing causes at least part of the difference in biomass generation between NEMS and POEMS in 2000 in the CECA Competitive case. In addition, because coal prices are projected to fall over the entire projection period in this analysis, biomass co-firing becomes relatively less attractive over time, and both models begin to reduce its role in generation by 2015. NEMS finds it economical to begin reducing co-firing earlier than POEMS.

NEMS, like POEMS, does not quite reach the 7.5-percent RPS target by 2010, because the renewable credit price exceeds the proposed 1.5 cent per kilowatthour cap. By 2010, qualified renewable generation in both NEMS and POEMS reaches 7.0 percent of sales (Table 6). However, POEMS exceeds the 7.5-percent required share by 2015, while NEMS reaches only 7.1 percent by 2015. The POEMS model goes over the 7.5 percent required because in the *Supporting Analysis* it was assumed that green power programs—independent of the RPS—would succeed in stimulating nonhydroelectric generation equal to 0.3 percent of total sales. The phase-in of the biomass co-firing share in NEMS (the actual share today is near zero) in the early years prevents the renewable share from growing as fast as it does in POEMS. And, in the later years, NEMS finds it more economical to reduce the co-firing of biomass and resume burning coal because of coal's declining price and the 1.5-cent cap on the renewable credit price.

Table 6. Comparison of NEMS and POEMS Results for RPS-Qualifying Renewable Share of Total Electricity Sales in the CECA Competitive Case, 2000-2015
(Percent)

Model	2000	2005	2010	2015
POEMS	4.1	5.4	7.0	7.7
NEMS	3.0	5.3	7.0	7.1

Sources: **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999). **NEMS:** National Energy Modeling System runs CECABAS1.D082799A (CECA Reference) and CECACMP2.D082899A (CECA Competitive).

Generating Capacity by Type

As would be expected because of the similarities in generation by fuel in the two models, the amount of capacity by type in the models is also quite close (Table 7). There are some differences, however. In both the CECA Reference and Competitive cases, NEMS relies more heavily on combustion turbines and existing fossil steam, and less on combined-cycle plants, than does POEMS. The NEMS model also builds slightly more capacity than POEMS in most years. The load shape data sources for the two models—power control area data for POEMS and NERC region data for NEMS—are different, and the load curves used in the models are constructed slightly differently. The more peaked the load curve is, the more likely the model is to build simple combustion turbines, whereas a flatter load curve would favor combined-cycle facilities.

In both NEMS and POEMS, large numbers of existing oil and gas steam plants are retired, along with older nuclear plants. Slightly more are retired in the CECA Competitive cases than in the Reference cases. The NEMS model finds it economical to use existing fossil steam plants together with new turbines rather than build as many new combined-cycle facilities as POEMS does. Other possible factors are differences in the cost and performance data used for existing plants. NEMS and POEMS use much of the same historical data, but POEMS assigns plant-specific values for annual maintenance capital expenditures while NEMS uses an average value for all plants of the same type. The more disaggregated approach used by POEMS may make it appear more economically attractive to retire more existing oil and gas steam plants ("Other Fossil" in Table 7) and replace them with new combined-cycle plants.

Table 7. Comparison of NEMS and POEMS Results for Electricity Generating Capability by Plant Type in Two Cases, 2000-2015
(Gigawatts)

Plant Type	2000		2005		2010		2015	
	POEMS	NEMS	POEMS	NEMS	POEMS	NEMS	POEMS	NEMS
	CECA Reference Case Results							
Combined Cycle	34.47	35.28	70.15	74.34	132.83	122.34	190.18	169.62
Coal	310.27	310.32	300.08	303.10	301.49	297.96	314.50	306.65
Turbines	71.67	86.65	108.20	116.15	146.77	148.98	170.60	188.69
Fuel Cells	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00
Hydroelectric	79.01	79.08	79.34	79.39	79.40	79.44	79.40	79.44
Nuclear	94.64	95.48	88.96	88.93	76.65	75.14	56.37	55.57
Other Fossil	136.83	138.88	98.52	105.64	50.59	94.25	45.65	91.60
Pumped Hydroelectric	21.52	21.52	21.52	21.52	21.52	21.52	21.52	21.52
Geothermal	3.06	3.79	2.81	4.00	2.98	4.24	3.19	4.41
Refuse	3.66	3.06	3.88	3.09	4.13	3.20	4.27	3.27
Wood	2.09	2.09	2.02	2.30	2.00	2.37	2.00	2.37
Solar Thermal	0.37	0.37	0.42	0.42	0.44	0.44	0.48	0.48
Wind	2.80	2.80	3.24	3.24	3.40	3.39	3.49	3.39
Solar Photovoltaic	0.04	0.04	0.14	0.14	0.30	0.30	0.46	0.46
Total	**762.66**	**779.37**	**779.28**	**802.27**	**822.51**	**853.59**	**892.11**	**927.48**
	CECA Competitive Case Results							
Combined Cycle	33.97	35.28	72.93	60.23	117.67	85.24	162.13	119.38
Coal	310.27	310.32	300.83	302.62	302.17	299.21	305.62	302.75
Turbines	68.69	89.78	113.68	123.42	136.48	160.56	169.07	190.52
Fuel Cells	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00
Hydroelectric	79.01	79.08	79.34	79.39	79.40	79.44	79.40	79.44
Nuclear	94.84	94.86	85.49	87.38	73.18	74.21	50.11	53.43
Other Fossil	138.83	138.88	99.30	116.50	71.79	104.40	68.54	91.59
Pumped Hydroelectric	21.52	21.52	21.52	21.52	21.52	21.52	21.52	21.52
Geothermal	3.07	3.06	3.15	3.23	3.42	3.43	3.50	3.64
Refuse	3.68	3.79	3.88	4.00	4.13	4.24	4.27	4.41
Wood	2.09	2.09	2.29	2.30	2.68	2.37	2.70	2.37
Solar Thermal	0.37	0.37	0.42	0.42	0.44	0.44	0.48	0.48
Wind	2.80	2.80	7.80	11.91	26.92	28.51	46.38	39.57
Solar Photovoltaic	0.04	0.04	0.14	0.14	0.30	0.30	0.46	0.46
Total	**759.18**	**781.88**	**790.77**	**813.07**	**840.11**	**863.88**	**914.20**	**909.58**

Sources: **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999). **NEMS:** National Energy Modeling System runs CECABAS1.D082799A (CECA Reference) and CECACMP2.D082899A (CECA Competitive).

Regional Comparison

No effort was made by EIA to replicate POEMS results with NEMS at either the national or regional level. For comparisons at the regional level, the POEMS results were aggregated to the NEMS level of detail. Here again, the two models produce projections that are similar, especially in terms of the direction and magnitude of changes between the CECA Competitive and CECA Reference cases produced by NEMS and POEMS. Detailed regional results are presented in Appendixes A and B.

In most regions, generation by fuel, capacity, and electricity prices in the comparable NEMS and POEMS cases are similar. As in POEMS, by 2010, electricity prices in the NEMS CECA Competitive case are lower than in the NEMS CECA Reference case in nearly all regions when aggregated to the NEMS level of detail. The only region in which prices are slightly higher in the CECA Competitive case produced by NEMS is the Northwest (Table 8). The Northwest has a large number of hydroelectric plants that keep prices low in a regulated average-cost environment. However, in a competitive environment—as in the CECA Competitive case—prices will be based on marginal costs that are higher than the current average costs in that region. The slightly lower price in the Northwest in the POEMS CECA Competitive case relative to the POEMS CECA Reference case may result from the exclusion of generation service sales taxes in the competitive price. NEMS includes approximately 1 mill per kilowatthour of generation sector gross receipts taxes in Northwest competitive prices.

Table 8. Comparison of NEMS and POEMS Results for Regional Electricity Prices in Two Cases, 2010
(1997 Mills per Kilowatthour)

Region	CECA Reference Case		CECA Competitive Case	
	NEMS	POEMS	NEMS	POEMS
ECAR	58.5	53.7	48.8	47.2
ERCOT	58.5	59.3	50.8	51.6
MAAC	75.2	74.5	58.8	63.5
MAIN	63.5	62.3	50.4	53.1
MAPP	51.7	53.8	47.5	46.2
NY	99.7	100.2	83.0	78.5
NE	82.8	90.1	76.5	78.5
FL	66.9	71.1	62.9	62.3
SERC	56.7	54.9	50.8	51.1
SPP	55.5	57.4	47.6	50.6
NWP	44.4	38.8	45.0	38.4
RA	67.1	65.2	63.1	52.6
CNV	88.7	91.6	71.2	69.7
United States	**63.6**	**63.3**	**55.1**	**54.7**

Sources: **POEMS:** U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999). **NEMS:** National Energy Modeling System runs CECABAS1.D082799A (CECA Reference) and CECACMP2.D082899A (CECA Competitive).

The only significant differences between the NEMS and POEMS results are in the Western regions—the Northwest Power Planning Council, Rocky Mountain / Arizona, and California-Southern Nevada. In both the CECA Reference and Competitive cases, NEMS finds it economical for California to continue meeting a significant portion of its power needs by purchasing power from the Northwest. On the other hand, POEMS chooses to reduce purchases from the Northwest while building new combined-cycle plants and retiring older oil and gas steam plants in California. In 2010 in the CECA Competitive cases, electricity generation in California is 39 billion kilowatthours (15 percent) less in the NEMS results than in POEMS.

Appendix A

CECA Reference Case: Detailed National and Regional Results, 2000, 2005, 2010, and 2015

Table A1. National Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Sales, Generation, Consumption, Capability, Emissions, Prices, and Expenditures	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Sales								
Residential	1,135	1,148	1,229	1,236	1,325	1,327	1,434	1,439
Commercial	1,073	1,069	1,150	1,141	1,236	1,223	1,321	1,312
Industrial	1,037	1,039	1,104	1,101	1,189	1,182	1,255	1,251
Transportation	17	18	29	31	43	44	53	55
Total	**3,261**	**3,274**	**3,512**	**3,508**	**3,794**	**3,776**	**4,065**	**4,057**
Generation								
Electric Generator[1]								
Coal	1,841	1,992	1,960	2,037	2,034	2,056	2,207	2,192
Natural Gas	365	372	604	619	930	963	1,193	1,259
Petroleum	125	84	62	42	37	25	30	21
Hydro	310	324	311	325	312	325	312	325
Nuclear	678	664	659	640	580	560	427	413
Geothermal	16	14	16	16	18	18	19	20
Municipal Solid Waste	23	24	24	25	26	27	27	28
Biomass[2]	10	9	11	11	11	11	11	11
Solar Thermal	1	1	1	1	1	1	1	1
Wind	6	6	7	7	8	8	8	8
Solar Photovoltaic	0	0	0	0	1	1	1	1
Total	**3,375**	**3,489**	**3,655**	**3,724**	**3,957**	**3,994**	**4,237**	**4,278**
Renewable Cogenerators[3]	41	48	44	52	49	57	53	60
Electricity Imports (Firm)	56	24	28	20	11	20	3	19
Electric Generator Consumption by Fuel (Quadrillion Btu)								
Coal	18.90	20.83	20.19	21.39	20.89	21.55	22.48	22.74
Natural Gas	3.62	3.71	5.23	5.33	7.12	7.49	8.68	9.27
Petroleum	1.31	0.88	0.64	0.44	0.40	0.26	0.32	0.22
Total	**23.83**	**25.42**	**26.06**	**27.16**	**28.41**	**29.30**	**31.48**	**32.22**
Capability (Gigawatts)[4]								
Combined Cycle	34.47	35.28	70.15	74.34	132.83	122.34	190.18	169.62
Coal	310.27	310.32	300.08	303.10	301.49	297.96	314.50	306.65
Combustion Turbines	71.67	86.65	108.20	116.15	146.77	148.98	170.60	188.69
Fuel Cells	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00
Hydro	79.01	79.08	79.34	79.39	79.40	79.44	79.40	79.44
Nuclear	94.84	95.48	88.96	88.93	76.65	75.14	56.37	55.57
Other Fossil Fuel	138.83	138.88	98.52	105.64	50.59	94.25	45.65	91.60
Pumped Storage	21.52	21.52	21.52	21.52	21.52	21.52	21.52	21.52
Geothermal	3.06	3.06	2.81	3.09	2.98	3.20	3.19	3.27
Municipal Solid Waste	3.68	3.79	3.88	4.00	4.13	4.24	4.27	4.41
Biomass[2]	2.09	2.09	2.02	2.30	2.00	2.37	2.00	2.37
Solar Thermal	0.37	0.37	0.42	0.42	0.44	0.44	0.48	0.48
Wind	2.80	2.80	3.24	3.24	3.40	3.39	3.49	3.39
Solar Photovoltaic	0.04	0.04	0.14	0.14	0.30	0.30	0.46	0.46
Total	**762.66**	**779.37**	**779.28**	**802.27**	**822.51**	**853.59**	**892.11**	**927.48**
Emissions								
Carbon (Million Metric Tons)	566	595	608	623	648	655	710	711
SO_2 (Thousand Short Tons)	10,223	11,380	9,774	10,390	8,997	8,950	9,067	9,090
Average Electricity Price (1997 Mills per Kilowatthour)	**66.5**	**65.6**	**65.8**	**65.6**	**63.3**	**63.6**	**60.0**	**59.1**
Electricity Expenditures (Billion 1997 Dollars)	**216.90**	**214.78**	**231.00**	**230.12**	**240.10**	**240.13**	**243.80**	**239.78**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Only includes renewable generation from traditional cogenerators.
[4]Includes nontraditional cogenerators.
Btu = British thermal unit. SO_2 = sulfur dioxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act,* DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A2. East Central Area Reliability Coordination Agreement (ECAR) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**515**	**507**	**546**	**535**	**583**	**570**	**617**	**606**
Generation[1]								
Coal	471	491	491	504	476	500	506	511
Natural Gas	18	15	31	30	105	92	123	127
Petroleum	4	1	4	1	4	1	4	1
Hydro	3	3	3	3	3	3	3	3
Nuclear	52	50	54	51	29	29	16	16
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	1	1	1	1	1	1	1	1
Biomass[2]	2	2	2	2	2	2	2	2
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**551**	**563**	**585**	**592**	**620**	**628**	**655**	**661**
Capability (Gigawatts)[3]								
Combined Cycle	2.17	2.17	4.29	3.19	13.11	3.19	18.90	3.24
Coal	84.51	84.67	76.63	77.60	73.20	70.48	73.20	69.69
Combustion Turbines	7.76	10.84	17.25	15.86	25.83	32.72	28.92	42.44
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	1.47	1.50	1.47	1.50	1.47	1.50	1.47	1.50
Nuclear	7.59	7.59	7.59	7.59	4.09	4.09	1.99	1.99
Other Fossil Fuel	3.66	3.66	2.33	3.66	2.33	3.66	2.33	3.66
Pumped Storage	3.58	4.75	3.58	4.75	3.58	4.75	3.58	4.75
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.11	0.11	0.12	0.12	0.14	0.14	0.15	0.16
Biomass[2]	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**111.10**	**115.54**	**113.51**	**114.51**	**124.00**	**120.77**	**130.79**	**127.67**
Emissions								
NO_x (Thousand Short Tons)	1,051	1,104	811	859	784	874	831	914
Average Electricity Price (1997 Mills per Kilowatthour)	**57.3**	**60.1**	**57.0**	**61.4**	**53.7**	**58.5**	**49.9**	**52.4**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A3. Electric Reliability Council of Texas (ERCOT) Regional Electricity Results: CECA Reference Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**231**	**242**	**251**	**262**	**274**	**284**	**296**	**308**
Generation[1]								
Coal	114	114	117	115	117	115	118	116
Natural Gas	89	103	106	121	130	145	150	168
Petroleum	3	2	2	1	2	1	2	1
Hydro	1	1	1	1	1	1	1	1
Nuclear	35	34	36	36	36	36	36	36
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	0	0	1	1	1	1	1	1
Biomass[2]	0	0	0	0	0	0	0	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**242**	**254**	**262**	**275**	**286**	**299**	**308**	**323**
Capability (Gigawatts)[3]								
Combined Cycle	3.29	3.41	12.50	9.52	19.50	18.26	22.96	22.40
Coal	15.77	15.58	16.10	15.58	16.10	15.58	16.24	15.66
Combustion Turbines	4.55	7.09	7.05	8.88	8.32	10.07	11.81	13.60
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.52	0.51	0.52	0.51	0.52	0.51	0.52	0.51
Nuclear	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80
Other Fossil Fuel	29.77	29.82	22.52	21.66	14.97	17.29	12.34	15.91
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Municipal Solid Waste	0.06	0.06	0.08	0.08	0.11	0.11	0.13	0.13
Biomass[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.19	0.19	0.19	0.19	0.12	0.19	0.12	0.19
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.01	0.01	0.03	0.03
Total	**58.94**	**61.46**	**63.76**	**61.23**	**64.45**	**66.83**	**68.94**	**73.23**
Emissions								
NO_x (Thousand Short Tons)	310	332	257	314	240	297	239	297
Average Electricity Price (1997 Mills per Kilowatthour)	**60.9**	**61.9**	**61.5**	**60.2**	**59.3**	**58.5**	**55.1**	**53.0**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A4. Mid-Atlantic Area Council (MAAC) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**248**	**246**	**264**	**261**	**281**	**278**	**297**	**296**
Generation[1]								
Coal	127	122	124	120	110	116	117	121
Natural Gas	18	15	44	42	90	78	135	123
Petroleum	10	4	5	2	4	2	4	2
Hydro	4	5	4	5	4	5	4	5
Nuclear	89	91	90	91	82	78	47	44
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	5	5	5	5	5	5	5	5
Biomass[2]	0	0	0	1	0	0	0	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**254**	**242**	**272**	**266**	**295**	**285**	**311**	**300**
Capability (Gigawatts)[3]								
Combined Cycle	3.70	3.93	7.31	7.13	14.53	11.93	22.92	18.08
Coal	20.30	19.40	19.95	19.31	16.97	19.17	16.84	19.19
Combustion Turbines	9.39	9.63	12.05	12.85	14.83	12.89	17.55	15.26
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	1.23	1.20	1.23	1.20	1.23	1.20	1.23	1.20
Nuclear	12.19	12.83	12.19	12.83	9.97	10.00	6.23	6.25
Other Fossil Fuel	8.96	8.96	3.95	5.02	2.37	4.76	2.37	4.76
Pumped Storage	1.67	1.34	1.67	1.34	1.67	1.34	1.67	1.34
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.77	0.81	0.77	0.81	0.77	0.81	0.77	0.81
Biomass[2]	0.07	0.06	0.07	0.06	0.07	0.06	0.07	0.06
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**58.26**	**58.17**	**59.17**	**60.55**	**62.39**	**62.16**	**69.62**	**66.96**
Emissions								
NO_x (Thousand Short Tons)	300	271	201	220	169	223	178	243
Average Electricity Price (1997 Mills per Kilowatthour)	**82.0**	**79.6**	**78.9**	**78.6**	**74.6**	**75.2**	**72.2**	**70.4**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A5. Mid-America Interconnected Network (MAIN) Regional Electricity Results: CECA Reference Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**222**	**235**	**235**	**247**	**250**	**261**	**264**	**277**
Generation[1]								
Coal	149	160	150	166	162	175	172	186
Natural Gas	3	3	6	6	12	13	23	27
Petroleum	1	1	1	1	1	1	1	1
Hydro	3	3	3	3	3	3	3	3
Nuclear	87	83	89	81	85	78	72	71
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	0	0	0	0	0	0	0	0
Biomass[2]	0	0	0	0	0	0	0	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**244**	**250**	**250**	**257**	**264**	**271**	**272**	**289**
Capability (Gigawatts)[3]								
Combined Cycle	0.29	0.29	1.24	0.90	2.77	2.43	4.88	5.55
Coal	27.81	27.66	25.11	26.41	25.11	26.41	25.29	26.57
Combustion Turbines	6.00	11.22	13.73	17.82	17.14	19.72	18.94	21.74
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
Nuclear	13.11	12.72	13.11	11.57	12.34	10.80	9.51	9.51
Other Fossil Fuel	4.76	4.76	2.46	3.18	0.29	3.18	0.29	3.18
Pumped Storage	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09
Biomass[2]	0.04	0.03	0.06	0.06		0.06	0.06	0.06
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00		0.00
Wind	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**53.35**	**58.03**	**57.05**	**61.30**	**59.07**	**63.96**	**60.34**	**67.97**
Emissions								
NO_x (Thousand Short Tons)	320	352	235	285	254	302	267	325
Average Electricity Price (1997 Mills per Kilowatthour)	**65.7**	**65.4**	**66.8**	**66.7**	**62.3**	**63.5**	**56.9**	**57.2**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A6. Mid-Continent Area Power Pool (MAPP) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**141**	**148**	**150**	**157**	**161**	**166**	**171**	**176**
Generation[1]								
Coal	111	133	125	143	131	145	135	147
Natural Gas	2	2	4	4	10	12	25	19
Petroleum	1	0	1	0	1	0	1	0
Hydro	12	17	12	17	12	17	12	17
Nuclear	24	25	12	12	11	11	8	8
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	1	2	1	2	2	2	2	2
Biomass[2]	0	0	1	1	1	1	1	1
Solar Thermal	0	0	0	0	0	0	0	0
Wind	1	1	2	2	2	2	2	2
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**153**	**181**	**158**	**180**	**170**	**190**	**185**	**196**
Capability (Gigawatts)[3]								
Combined Cycle	0.42	0.42	0.75	0.58	1.57	0.92	4.38	0.92
Coal	21.68	20.78	20.29	20.54	20.26	20.51	20.29	20.28
Combustion Turbines	4.97	6.42	5.69	9.70	7.82	11.62	8.87	17.86
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Nuclear	3.35	3.74	1.57	1.57	1.03	1.03	1.03	1.03
Other Fossil Fuel	0.61	0.61		0.60	0.30	0.60	0.30	0.60
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.20	0.20	0.23	0.23	0.27	0.27	0.29	0.29
Biomass[2]	0.11	0.11	0.21	0.23	0.13	0.23	0.13	0.23
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.52	0.52	0.68	0.68	0.68	0.68	0.68	0.68
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**35.27**	**36.21**	**33.13**	**37.54**	**35.46**	**39.26**	**39.37**	**45.29**
Emissions								
NO_x (Thousand Short Tons)	235	302	262	327	277	337	284	347
Average Electricity Price (1997 Mills per Kilowatthour)	**56.1**	**53.7**	**55.1**	**52.4**	**53.8**	**51.7**	**50.2**	**49.7**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A7. Northeast Power Coordinating Council/New England (NE) Regional Electricity Results: CECA Reference Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**115**	**115**	**121**	**122**	**128**	**128**	**135**	**134**
Generation[1]								
Coal	20	20	20	20	19	15	18	14
Natural Gas	24	21	50	48	62	75	82	88
Petroleum	25	17	8	6	8	2	2	1
Hydro	7	9	7	9	7	9	7	9
Nuclear	29	29	26	25	21	21	17	17
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	4	5	4	5	5	5	5	5
Biomass[2]	3	3	4	3	4	4	4	4
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	1	1	1	1
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**114**	**105**	**120**	**117**	**127**	**132**	**136**	**140**
Capability (Gigawatts)[3]								
Combined Cycle	2.13	2.21	5.60	5.91	7.91	9.99	11.10	11.97
Coal	3.05	3.05	2.84	3.05	2.84	3.05	2.84	3.05
Combustion Turbines	1.78	1.84	1.78	2.09	2.08	2.06	2.69	2.22
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Nuclear	4.32	4.32	2.78	3.65	2.78	2.78	2.28	2.28
Other Fossil Fuel	8.14	8.14	7.12	5.73	1.88	3.31	1.11	3.31
Pumped Storage	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.63	0.63	0.65	0.65	0.67	0.67	0.67	0.69
Biomass[2]	0.76	0.75	0.54	0.81	0.60	0.88	0.60	0.88
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.02	0.02	0.12	0.12	0.27	0.27	0.27	0.27
Solar Photovoltaic	0.00	0.00	0.01	0.01	0.05	0.04	0.05	0.04
Total	**24.49**	**24.63**	**25.11**	**25.70**	**22.75**	**26.72**	**25.28**	**28.39**
Emissions								
NO_x (Thousand Short Tons)	76	73	44	62	39	59	29	61
Average Electricity Price (1997 Mills per Kilowatthour)	**99.9**	**89.4**	**97.8**	**84.4**	**90.1**	**82.8**	**82.6**	**78.2**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A8. Northeast Power Coordinating Council/New York (NY) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**140**	**145**	**148**	**152**	**157**	**160**	**164**	**168**
Generation[1]								
Coal	12	34	20	34	25	29	27	33
Natural Gas	44	41	61	59	82	90	95	106
Petroleum	26	18	13	6	2	1	2	1
Hydro	29	20	31	21	32	21	32	21
Nuclear	34	33	27	27	14	14	8	8
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	2	2	2	2	2	2	2	2
Biomass[2]	0	0	0	1	0	0	0	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**147**	**148**	**155**	**150**	**157**	**158**	**166**	**172**
Capability (Gigawatts)[3]								
Combined Cycle	4.62	4.62	5.77	7.34	11.30	12.39	15.20	14.74
Coal	3.98	4.92	3.98	4.92	3.82	4.92	3.68	4.92
Combustion Turbines	4.10	4.10	4.09	4.09	4.09	4.09	4.09	5.27
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	4.63	4.63	4.91	4.91	4.96	4.96	4.96	4.96
Nuclear	4.91	4.91	3.11	3.11	2.03	2.03	1.10	1.09
Other Fossil Fuel	12.39	12.39	8.40	6.18	1.21	3.11	1.21	3.11
Pumped Storage	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Biomass[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**36.28**	**37.23**	**31.92**	**32.21**	**29.06**	**33.16**	**31.90**	**35.77**
Emissions								
NO_x (Thousand Short Tons)	56	99	54	78	42	72	44	84
Average Electricity Price (1997 Mills per Kilowatthour)	**109.7**	**103.1**	**105.8**	**101.9**	**102.8**	**99.7**	**96.8**	**93.2**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A9. Southeastern Electric Reliability Council/Florida (FL) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**176**	**175**	**193**	**191**	**211**	**209**	**230**	**228**
Generation[1]								
Coal	64	73	86	73	107	74	135	79
Natural Gas	44	30	66	54	82	88	84	117
Petroleum	34	22	9	15	4	12	3	9
Hydro	0	0	0	0	0	0	0	0
Nuclear	29	28	29	27	22	21	12	11
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	4	4	4	4	4	4	4	4
Biomass[2]	0	0	0	0	0	0	0	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**175**	**158**	**194**	**175**	**219**	**198**	**239**	**221**
Capability (Gigawatts)[3]								
Combined Cycle	5.59	5.12	11.04	7.82	14.48	12.93	16.65	16.74
Coal	9.94	10.09	13.18	10.09	15.71	10.10	19.57	10.59
Combustion Turbines	5.88	5.54	8.95	6.38	11.66	7.11	12.35	9.78
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Nuclear	3.82	3.82	3.82	3.82	3.01	3.01	1.68	1.68
Other Fossil Fuel	13.32	13.32	8.59	12.35	4.17	11.89	4.17	11.63
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Biomass[2]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**39.38**	**38.73**	**46.42**	**41.31**	**49.87**	**45.87**	**55.26**	**51.26**
Emissions								
NO_x (Thousand Short Tons)	226	222	166	224	148	225	144	232
Average Electricity Price (1997 Mills per Kilowatthour)	**72.0**	**68.4**	**72.5**	**68.0**	**71.1**	**66.9**	**68.5**	**62.9**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A10. Southeastern Electric Reliability Council (SERC) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**581**	**567**	**631**	**612**	**687**	**665**	**741**	**720**
Generation[1]								
Coal	378	419	412	430	426	437	454	482
Natural Gas	10	8	27	41	87	92	178	172
Petroleum	4	3	4	2	5	3	5	2
Hydro	38	38	38	38	38	38	38	38
Nuclear	187	182	183	179	166	161	106	98
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	1	2	2	2	2	3	2	3
Biomass[2]	1	0	1	0	1	0	1	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**618**	**652**	**666**	**693**	**723**	**734**	**783**	**795**
Capability (Gigawatts)[3]								
Combined Cycle	3.01	3.00	5.03	7.88	15.31	14.40	31.82	30.24
Coal	65.78	65.63	62.71	65.63	62.64	65.40	63.24	67.17
Combustion Turbines	13.34	13.16	20.51	19.51	27.69	25.18	31.87	30.47
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	11.87	11.87	11.93	11.93	11.93	11.93	11.93	11.93
Nuclear	25.47	25.58	24.71	24.83	21.34	21.46	14.27	13.56
Other Fossil Fuel	3.15	3.15	2.77	3.09	2.72	2.98	2.57	2.89
Pumped Storage	7.52	6.68	7.52	6.68	7.52	6.68	7.52	6.68
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.29	0.37	0.34	0.41	0.39	0.46	0.42	0.49
Biomass[2]	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**130.59**	**129.61**	**135.67**	**140.12**	**149.70**	**148.65**	**163.79**	**163.61**
Emissions								
NO_x (Thousand Short Tons)	768	881	618	736	639	764	674	838
Average Electricity Price								
(1997 Mills per Kilowatthour)	**57.2**	**56.4**	**55.9**	**58.1**	**54.9**	**56.7**	**53.8**	**54.0**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A11. Southwest Power Pool (SPP) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**280**	**284**	**304**	**305**	**330**	**329**	**354**	**355**
Generation[1]								
Coal	186	202	191	203	196	204	201	207
Natural Gas	40	31	70	70	91	86	106	109
Petroleum	4	4	1	0	3	0	3	1
Hydro	8	7	8	7	8	7	8	7
Nuclear	46	44	46	44	46	44	37	35
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	0	0	0	1	0	1	0	1
Biomass[2]	0	0	0	0	0	0	0	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**283**	**288**	**318**	**324**	**344**	**342**	**357**	**360**
Capability (Gigawatts)[3]								
Combined Cycle	2.07	2.07	4.67	8.16	9.99	11.45	13.85	15.54
Coal	27.80	27.98	28.36	28.60	28.31	28.61	28.84	28.96
Combustion Turbines	5.22	5.15	7.81	7.29	15.33	8.90	19.31	11.86
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	2.81	2.84	2.81	2.84	2.81	2.84	2.81	2.84
Nuclear	6.05	5.93	6.05	5.93	6.05	5.93	4.27	4.16
Other Fossil Fuel	30.27	30.27	21.87	22.92	11.06	22.81	11.06	22.56
Pumped Storage	0.51	0.50	0.51	0.50	0.51	0.50	0.51	0.50
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.07	0.07	0.10	0.10	0.13	0.13	0.15	0.15
Biomass[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.00	0.01	0.01	0.02	0.02	0.05	0.05
Total	**74.78**	**74.82**	**72.16**	**76.35**	**74.20**	**81.19**	**80.85**	**86.62**
Emissions								
NO_x (Thousand Short Tons)	426	463	426	441	412	445	403	443
Average Electricity Price (1997 Mills per Kilowatthour)	**58.8**	**54.1**	**58.0**	**55.3**	**57.4**	**55.5**	**54.2**	**51.3**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A12. Southwest Systems Coordinating Council/Rocky Mountain Power Area and Arizona (RA) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**133**	**116**	**151**	**131**	**167**	**145**	**184**	**161**
Generation[1]								
Coal	102	98	103	99	109	107	118	118
Natural Gas	7	27	13	48	28	58	35	48
Petroleum	0	1	1	0	1	0	1	0
Hydro	12	13	12	13	12	13	12	13
Nuclear	28	21	28	22	28	22	28	22
Geothermal	3	3	3	3	3	3	3	3
Municipal Solid Waste	0	0	0	0	0	1	0	1
Biomass[2]	0	0	0	0	0	0	0	0
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**153**	**163**	**162**	**185**	**181**	**204**	**199**	**205**
Capability (Gigawatts)[3]								
Combined Cycle	1.36	1.93	1.51	5.92	3.91	8.51	5.25	8.99
Coal	14.15	13.25	14.10	13.40	14.78	14.47	16.23	16.00
Combustion Turbines	2.58	3.67	3.78	3.87	5.85	4.13	6.94	4.41
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	3.98	3.98	3.98	3.98	3.98	3.98	3.98	3.98
Nuclear	3.81	2.99	3.81	2.99	3.81	2.99	3.81	2.99
Other Fossil Fuel	2.59	2.59	2.25	2.22	2.25	2.22	2.25	2.22
Pumped Storage	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
Geothermal	0.35	0.31	0.35	0.32	0.36	0.32	0.37	0.34
Municipal Solid Waste	0.04	0.04	0.06	0.06	0.08	0.08	0.09	0.09
Biomass[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.02	0.02	0.06	0.06	0.06	0.06	0.07	0.07
Wind	0.08	0.06	0.08	0.06	0.08	0.06	0.08	0.06
Solar Photovoltaic	0.01	0.01	0.04	0.04	0.06	0.06	0.09	0.08
Total	**29.69**	**29.57**	**30.72**	**33.64**	**35.93**	**37.60**	**39.86**	**39.95**
Emissions								
NO_x (Thousand Short Tons)	223	230	230	231	228	233	227	229
Average Electricity Price (1997 Mills per Kilowatthour)	**66.2**	**68.0**	**64.3**	**67.7**	**65.2**	**67.1**	**63.3**	**63.1**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A13. Western Systems Coordinating Council/Northwest Power Pool (NWP) Regional Electricity Results: CECA Reference Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**233**	**230**	**254**	**252**	**277**	**276**	**300**	**300**
Generation[1]								
Coal	77	83	81	85	82	89	88	98
Natural Gas	11	18	14	49	24	64	45	87
Petroleum	1	0	1	0	1	0	1	0
Hydro	153	164	152	163	152	163	152	163
Nuclear	7	6	7	7	8	8	8	8
Geothermal	1	1	1	3	3	5	4	8
Municipal Solid Waste	0	1	1	1	1	1	1	1
Biomass[2]	1	1	1	1	1	1	1	1
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**251**	**274**	**258**	**310**	**271**	**332**	**301**	**367**
Capability (Gigawatts)[3]								
Combined Cycle	1.88	2.21	1.13	5.77	2.74	8.39	5.87	11.98
Coal	11.37	11.58	11.37	11.88	11.57	12.38	12.40	13.55
Combustion Turbines	1.29	3.17	0.90	3.18	0.91	3.18	0.73	2.95
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	35.03	35.05	35.03	35.03	35.03	35.03	35.03	35.03
Nuclear	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11
Other Fossil Fuel	0.72	0.72	0.42	0.72	0.42	0.23	0.42	0.23
Pumped Storage	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	0.21	0.21	0.21	0.45	0.45	0.71	0.74	0.97
Municipal Solid Waste	0.11	0.11	0.13	0.13	0.17	0.17	0.19	0.19
Biomass[2]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Solar Thermal	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02
Wind	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Solar Photovoltaic	0.00	0.00	0.01	0.03	0.05	0.09	0.10	0.14
Total	**52.20**	**54.66**	**50.80**	**58.81**	**52.94**	**61.78**	**57.10**	**66.65**
Emissions								
NO_x (Thousand Short Tons)	157	171	167	184	164	187	164	194
Average Electricity Price (1997 Mills per Kilowatthour)	**41.5**	**43.5**	**39.6**	**45.0**	**38.8**	**44.4**	**37.3**	**42.4**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table A14. Western Systems Coordinating Council/California-Southern Nevada Power (CNV) Regional Electricity Results: CECA Reference Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**247**	**241**	**267**	**262**	**290**	**284**	**313**	**307**
Generation[1]								
Coal	30	42	40	45	75	51	117	81
Natural Gas	55	58	111	48	128	71	111	68
Petroleum	10	11	11	6	3	1	2	0
Hydro	40	45	40	45	40	45	40	45
Nuclear	32	38	32	38	32	38	32	38
Geothermal	12	10	12	10	12	10	12	9
Municipal Solid Waste	2	2	2	2	2	2	2	2
Biomass[2]	2	2	2	2	2	2	2	2
Solar Thermal	1	1	1	1	1	1	1	1
Wind	4	4	4	5	5	5	5	5
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**189**	**213**	**256**	**201**	**300**	**225**	**324**	**252**
Capability (Gigawatts)[3]								
Combined Cycle	3.96	3.91	9.32	4.20	15.71	7.56	16.39	9.21
Coal	4.16	5.73	5.47	6.10	10.19	6.89	15.84	11.03
Combustion Turbines	4.82	4.83	4.63	4.61	5.22	7.33	6.53	10.83
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	11.33	11.33	11.33	11.33	11.33	11.33	11.33	11.33
Nuclear	4.31	5.13	4.31	5.13	4.31	5.13	4.31	5.13
Other Fossil Fuel	20.48	20.48	15.54	18.31	6.62	18.21	5.23	17.53
Pumped Storage	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73
Geothermal	2.51	2.54	2.25	2.32	2.17	2.17	2.08	1.97
Municipal Solid Waste	0.36	0.36	0.37	0.36	0.37	0.36	0.37	0.36
Biomass[2]	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
Solar Thermal	0.35	0.35	0.36	0.36	0.37	0.37	0.39	0.38
Wind	1.95	1.96	2.11	2.13	2.20	2.13	2.28	2.13
Solar Photovoltaic	0.02	0.02	0.07	0.04	0.11	0.07	0.16	0.12
Total	**58.34**	**60.72**	**59.85**	**58.99**	**62.70**	**65.64**	**69.01**	**74.12**
Emissions								
NO_x (Thousand Short Tons)	78	99	77	95	61	103	57	104
Average Electricity Price (1997 Mills per Kilowatthour)	**92.6**	**97.3**	**96.4**	**93.4**	**91.6**	**88.7**	**86.4**	**82.6**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Appendix B

CECA Competitive Case: Detailed National and Regional Results, 2000, 2005, 2010, and 2015

Table B1. National Electricity Results: CECA Competitive Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Sales, Generation, Consumption, Capability, Emissions, Prices, and Expenditures	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Sales								
Residential	1,174	1,171	1,263	1,254	1,352	1,341	1,466	1,452
Commercial	1,103	1,096	1,160	1,159	1,219	1,217	1,299	1,297
Industrial	1,037	1,027	1,063	1,071	1,092	1,112	1,135	1,151
Transportation	17	18	29	31	43	44	53	55
Total	**3,330**	**3,312**	**3,515**	**3,514**	**3,706**	**3,714**	**3,954**	**3,956**
Generation								
Electric Generator[1]								
Coal	1,932	2,037	1,945	2,047	2,012	2,080	2,153	2,213
Natural Gas	330	349	540	505	671	654	913	904
Petroleum	85	77	25	30	11	18	13	17
Hydro	310	324	312	325	319	325	322	325
Nuclear	694	673	661	652	581	574	400	413
Geothermal	16	14	18	17	20	20	21	23
Municipal Solid Waste	23	24	24	25	26	27	27	28
Biomass[2]	57	24	104	73	106	78	93	55
Solar Thermal	1	1	1	1	1	1	1	1
Wind	6	6	20	37	66	92	117	129
Solar Photovoltaic	0	0	0	0	1	1	1	1
Total	**3,453**	**3,529**	**3,651**	**3,712**	**3,816**	**3,871**	**4,061**	**4,111**
Renewable Cogenerators[3]	41	48	45	52	51	59	54	64
Electricity Imports (Firm)	54	24	28	20	51	20	54	19
Electric Generator Consumption by Fuel (Quadrillion Btu)								
Coal	19.76	21.21	19.60	20.95	19.86	20.73	21.25	21.99
Natural Gas	3.27	3.46	4.52	4.47	5.10	5.34	6.64	6.89
Petroleum	0.90	0.81	0.25	0.31	0.12	0.19	0.14	0.18
Total	**23.93**	**25.47**	**24.37**	**25.73**	**25.08**	**26.26**	**28.03**	**29.06**
Capability (Gigawatts)[4]								
Combined Cycle	33.97	35.28	72.93	60.23	117.67	85.24	162.13	119.38
Coal	310.27	310.32	300.83	302.62	302.17	299.21	305.62	302.75
Combustion Turbines	68.69	89.78	113.68	123.42	136.48	160.56	169.07	190.52
Fuel Cells	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00
Hydro	79.01	79.08	79.34	79.39	79.40	79.44	79.40	79.44
Nuclear	94.84	94.86	85.49	87.38	73.18	74.21	50.11	53.43
Other Fossil Fuel	138.83	138.88	99.30	116.50	71.79	104.40	68.54	91.59
Pumped Storage	21.52	21.52	21.52	21.52	21.52	21.52	21.52	21.52
Geothermal	3.07	3.06	3.15	3.23	3.42	3.43	3.50	3.64
Municipal Solid Waste	3.68	3.79	3.88	4.00	4.13	4.24	4.27	4.41
Biomass[2]	2.09	2.09	2.29	2.30	2.68	2.37	2.70	2.37
Solar Thermal	0.37	0.37	0.42	0.42	0.44	0.44	0.48	0.48
Wind	2.80	2.80	7.80	11.91	26.92	28.51	46.38	39.57
Solar Photovoltaic	0.04	0.04	0.14	0.14	0.30	0.30	0.46	0.46
Total	**759.18**	**781.88**	**790.77**	**813.07**	**840.11**	**863.88**	**914.20**	**909.58**
Emissions								
Carbon (Million Metric Tons)	575	600	575	597	587	602	646	662
SO_2 (Thousand Short Tons)	10,320	11,380	9,746	10,450	9,024	9,140	9,053	8,950
Average Electricity Price (1997 Mills per Kilowatthour)	**56.5**	**59.9**	**57.8**	**58.2**	**54.7**	**55.1**	**52.2**	**52.5**
Electricity Expenditures (Billion 1997 Dollars)	**188.15**	**198.41**	**203.17**	**204.52**	**202.72**	**204.66**	**206.40**	**207.66**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Only includes renewable generation from traditional cogenerators.
[4]Includes nontraditional cogenerators.
Btu = British thermal unit. SO_2 = sulfur dioxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act,* DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECABAS1.D082799A.

Table B2. East Central Area Reliability Coordination Agreement (ECAR) Regional Electricity Results: CECA Competitive Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**525**	**517**	**546**	**542**	**569**	**566**	**601**	**596**
Generation[1]								
Coal	490	501	491	493	482	508	508	537
Natural Gas	14	13	26	16	62	34	77	73
Petroleum	2	0	0	0	0	0	0	0
Hydro	3	3	3	3	3	3	3	3
Nuclear	53	51	48	53	24	30	17	17
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	1	1	1	1	1	1	1	1
Biomass[2]	13	6	25	25	24	24	26	16
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	1	2	3
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**575**	**575**	**593**	**591**	**597**	**602**	**635**	**650**
Capability (Gigawatts)[3]								
Combined Cycle	2.17	2.17	3.88	2.52	8.67	3.37	11.60	6.22
Coal	84.51	84.67	76.78	78.68	75.97	75.44	75.97	75.44
Combustion Turbines	7.40	10.25	19.29	15.09	25.64	24.54	30.90	28.98
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	1.47	1.50	1.47	1.50	1.47	1.50	1.47	1.50
Nuclear	7.59	7.59	6.59	7.59	3.09	4.09	1.99	1.99
Other Fossil Fuel	3.66	3.66	3.52	3.66	3.52	3.66	3.52	3.66
Pumped Storage	3.58	4.75	3.58	4.75	3.58	4.75	3.58	4.75
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.11	0.11	0.12	0.12	0.14	0.14	0.15	0.16
Biomass[2]	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.02	0.00	0.18	0.34	0.83	0.80
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**110.74**	**114.95**	**115.50**	**114.17**	**122.50**	**118.08**	**130.26**	**123.74**
Emissions								
NO_x (Thousand Short Tons)	1,098	1,126	816	846	790	865	836	911
Average Electricity Price (1997 Mills per Kilowatthour)	**47.6**	**49.2**	**49.7**	**49.8**	**47.2**	**48.8**	**43.5**	**46.3**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B3. Electric Reliability Council of Texas (ERCOT) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**237**	**244**	**252**	**260**	**266**	**278**	**287**	**297**
Generation[1]								
Coal	118	118	117	118	118	117	118	119
Natural Gas	88	97	99	109	104	109	121	123
Petroleum	2	2	1	1	1	1	1	1
Hydro	1	1	1	1	1	1	1	1
Nuclear	36	35	37	37	37	37	37	37
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	0	0	1	1	1	1	1	1
Biomass[2]	3	1	6	3	6	4	6	2
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	1	0	5	6	7	10
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**248**	**254**	**263**	**270**	**273**	**276**	**293**	**294**
Capability (Gigawatts)[3]								
Combined Cycle	3.28	3.36	11.08	7.88	17.39	10.28	20.93	13.24
Coal	15.77	15.58	15.93	15.58	15.93	15.58	15.93	15.58
Combustion Turbines	3.59	5.88	6.17	8.45	7.96	13.46	10.67	18.20
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.52	0.51	0.52	0.51	0.52	0.51	0.52	0.51
Nuclear	4.80	4.80	4.80	4.80	4.80	4.80	4.80	4.80
Other Fossil Fuel	29.77	29.82	22.88	23.19	17.56	18.84	17.20	13.89
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.06	0.06	0.08	0.08	0.11	0.11	0.13	0.13
Biomass[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.19	0.19	0.55	0.19	2.23	2.15	2.87	3.39
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.01	0.01	0.03	0.03
Total	**57.97**	**60.20**	**62.02**	**60.69**	**66.52**	**65.75**	**73.07**	**69.78**
Emissions								
NO_x (Thousand Short Tons)	319	334	261	314	235	281	234	276
Average Electricity Price (1997 Mills per Kilowatthour)	**54.7**	**57.1**	**53.1**	**54.7**	**51.6**	**50.8**	**46.0**	**45.8**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B4. Mid-Atlantic Area Council (MAAC) Regional Electricity Results: CECA Competitive Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**254**	**251**	**264**	**264**	**275**	**276**	**290**	**291**
Generation[1]								
Coal	130	125	123	125	124	126	132	130
Natural Gas	16	14	50	40	63	59	106	94
Petroleum	5	3	2	2	3	1	4	1
Hydro	4	5	4	5	4	5	4	5
Nuclear	91	89	93	89	84	80	31	46
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	5	5	5	5	5	5	5	5
Biomass[2]	3	2	6	4	6	4	6	4
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	3	8	9	10
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**253**	**244**	**282**	**270**	**291**	**289**	**296**	**295**
Capability (Gigawatts)[3]								
Combined Cycle	3.70	3.90	8.09	6.92	10.85	9.66	16.63	13.61
Coal	20.30	19.40	19.95	19.31	19.79	19.17	19.79	19.17
Combustion Turbines	9.39	9.46	13.05	12.91	14.31	13.07	16.45	14.63
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	1.23	1.20	1.23	1.20	1.23	1.20	1.23	1.20
Nuclear	12.19	12.21	12.19	12.21	9.97	10.00	4.04	6.25
Other Fossil Fuel	8.96	8.96	5.26	6.25	5.26	6.25	5.26	6.07
Pumped Storage	1.67	1.34	1.67	1.34	1.67	1.34	1.67	1.34
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.77	0.81	0.77	0.81	0.77	0.81	0.77	0.81
Biomass[2]	0.07	0.06	0.07	0.06	0.07	0.06	0.07	0.06
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.02	0.00	1.20	2.71	3.57	3.43
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**58.26**	**57.34**	**62.27**	**61.02**	**65.10**	**64.27**	**69.45**	**66.59**
Emissions								
NO_x (Thousand Short Tons)	293	279	197	220	193	222	211	245
Average Electricity Price (1997 Mills per Kilowatthour)	**66.8**	**67.6**	**69.0**	**63.8**	**63.5**	**58.8**	**61.8**	**58.4**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B5. Mid-America Interconnected Network (MAIN) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**228**	**240**	**237**	**251**	**247**	**260**	**261**	**273**
Generation[1]								
Coal	148	159	153	161	161	167	178	183
Natural Gas	2	3	3	5	4	8	7	18
Petroleum	1	1	0	0	0	0	0	1
Hydro	3	3	3	3	3	3	3	3
Nuclear	88	85	85	84	82	81	75	74
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	0	0	0	0	0	0	0	0
Biomass[2]	5	1	8	9	9	8	9	3
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**248**	**251**	**254**	**262**	**259**	**268**	**274**	**282**
Capability (Gigawatts)[3]								
Combined Cycle	0.29	0.29	0.60	1.23	1.61	2.20	2.78	3.72
Coal	27.81	27.66	27.02	25.42	26.88	25.42	26.88	25.45
Combustion Turbines	4.87	11.53	15.22	18.10	18.27	19.58	20.87	21.35
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
Nuclear	13.11	12.72	11.57	11.57	10.80	10.80	9.51	9.51
Other Fossil Fuel	4.76	4.76	1.93	4.66	1.40	4.66	1.40	4.66
Pumped Storage	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.09
Biomass[2]	0.04	0.03	0.06	0.06	0.06	0.06	0.06	0.06
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**52.22**	**58.34**	**57.76**	**62.40**	**60.37**	**64.07**	**62.85**	**66.11**
Emissions								
NO_x (Thousand Short Tons)	319	347	236	279	241	279	277	305
Average Electricity Price								
(1997 Mills per Kilowatthour)	**53.2**	**56.3**	**56.2**	**53.6**	**53.1**	**50.4**	**49.0**	**47.2**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B6. Mid-Continent Area Power Pool (MAPP) Regional Electricity Results: CECA Competitive Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**145**	**149**	**152**	**157**	**160**	**164**	**169**	**172**
Generation[1]								
Coal	117	137	132	149	139	150	152	154
Natural Gas	2	2	2	3	4	4	9	6
Petroleum	1	0	0	0	0	0	0	0
Hydro	12	17	12	17	12	17	12	17
Nuclear	24	25	12	12	11	11	0	0
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	1	2	1	2	2	2	2	2
Biomass[2]	3	1	8	1	8	2	4	1
Solar Thermal	0	0	0	0	0	0	0	0
Wind	1	1	2	2	2	4	12	13
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**161**	**186**	**169**	**185**	**178**	**189**	**190**	**193**
Capability (Gigawatts)[3]								
Combined Cycle	0.42	0.42	0.57	0.46	1.86	0.53	2.65	0.55
Coal	21.68	20.78	20.94	20.71	20.92	20.18	20.92	20.18
Combustion Turbines	4.97	6.35	5.72	9.67	7.41	12.30	9.39	13.50
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
Nuclear	3.35	3.74	1.57	1.57	1.03	1.03	0.00	0.00
Other Fossil Fuel	0.61	0.61	0.56	0.60	0.56	0.60	0.56	0.60
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.20	0.20	0.23	0.23	0.27	0.27	0.29	0.29
Biomass[2]	0.11	0.11	0.23	0.23	0.23	0.23	0.23	0.23
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.52	0.52	0.68	0.68	0.69	1.27	4.28	3.93
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**35.27**	**36.13**	**33.90**	**37.56**	**36.37**	**39.81**	**41.70**	**42.68**
Emissions								
NO_x (Thousand Short Tons)	247	309	288	326	294	318	315	326
Average Electricity Price (1997 Mills per Kilowatthour)	**44.7**	**51.0**	**47.2**	**51.6**	**46.2**	**47.5**	**45.3**	**47.6**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B7. Northeast Power Coordinating Council/New England (NE) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**117**	**116**	**121**	**120**	**125**	**124**	**133**	**131**
Generation[1]								
Coal	22	21	22	20	20	20	16	19
Natural Gas	22	21	43	47	60	67	79	83
Petroleum	24	17	7	5	1	2	1	1
Hydro	7	9	7	9	7	9	7	9
Nuclear	30	29	27	26	22	21	13	18
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	4	5	4	5	5	5	5	6
Biomass[2]	3	3	5	3	5	4	4	4
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	1	0	1	1	5	1
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**114**	**105**	**115**	**117**	**121**	**130**	**131**	**140**
Capability (Gigawatts)[3]								
Combined Cycle	2.13	2.18	4.93	5.79	7.89	7.31	10.84	9.66
Coal	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05
Combustion Turbines	1.78	1.78	1.78	1.98	1.83	4.02	2.91	5.72
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02
Nuclear	4.32	4.32	2.78	3.65	2.78	2.78	1.16	2.28
Other Fossil Fuel	8.14	8.14	5.45	5.70	1.84	2.96	0.87	0.81
Pumped Storage	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.63	0.63	0.65	0.65	0.67	0.67	0.67	0.69
Biomass[2]	0.76	0.75	0.81	0.81	0.67	0.88	0.67	0.88
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.02	0.02	0.19	0.12	0.45	0.34	1.83	0.40
Solar Photovoltaic	0.00	0.00	0.01	0.01	0.05	0.04	0.05	0.04
Total	**24.49**	**24.53**	**23.33**	**25.43**	**22.90**	**25.73**	**25.72**	**27.21**
Emissions								
NO_x (Thousand Short Tons)	78	73	48	60	34	67	25	70
Average Electricity Price (1997 Mills per Kilowatthour)	**82.6**	**86.1**	**82.0**	**80.8**	**78.5**	**76.5**	**68.1**	**67.7**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B8. Northeast Power Coordinating Council/New York (NY) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**143**	**150**	**149**	**156**	**155**	**161**	**163**	**168**
Generation[1]								
Coal	27	35	28	36	27	36	27	36
Natural Gas	34	41	43	57	72	65	82	82
Petroleum	13	17	2	6	1	2	1	1
Hydro	29	20	31	21	32	21	32	21
Nuclear	35	34	22	21	9	9	9	9
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	2	2	2	2	2	2	2	2
Biomass[2]	1	1	1	2	1	2	1	2
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	1	2	1
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**141**	**150**	**130**	**145**	**144**	**138**	**156**	**154**
Capability (Gigawatts)[3]								
Combined Cycle	4.62	4.62	5.75	6.28	10.03	7.94	11.69	10.97
Coal	3.98	4.92	3.76	4.92	3.73	4.92	3.73	4.92
Combustion Turbines	4.10	4.10	4.09	4.09	4.09	6.48	4.09	8.53
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	4.63	4.63	4.91	4.91	4.96	4.96	4.96	4.96
Nuclear	4.91	4.91	2.18	2.18	1.10	1.09	1.10	1.09
Other Fossil Fuel	12.39	12.39	8.73	8.17	3.15	5.24	3.15	1.80
Pumped Storage	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Biomass[2]	0.04	0.04	0.04	0.04	0.07	0.04	0.07	0.04
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.02	0.01	0.18	0.18	0.57	0.31
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**36.28**	**37.23**	**31.09**	**32.21**	**28.91**	**32.47**	**30.95**	**34.25**
Emissions								
NO_x (Thousand Short Tons)	67	102	43	85	36	82	38	84
Average Electricity Price (1997 Mills per Kilowatthour)	**92.4**	**84.0**	**88.2**	**83.1**	**81.2**	**83.0**	**72.4**	**75.1**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B9. Southeastern Electric Reliability Council/Florida (FL) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**180**	**177**	**193**	**192**	**208**	**207**	**225**	**225**
Generation[1]								
Coal	73	76	85	76	97	77	107	101
Natural Gas	36	29	65	52	83	75	103	87
Petroleum	22	21	5	13	2	10	2	10
Hydro	0	0	0	0	0	0	0	0
Nuclear	29	28	29	27	23	21	13	11
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	4	4	4	4	4	4	4	4
Biomass[2]	2	1	3	1	4	2	2	2
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**167**	**159**	**193**	**174**	**213**	**189**	**233**	**214**
Capability (Gigawatts)[3]								
Combined Cycle	5.15	5.12	10.23	6.82	16.13	9.53	21.13	11.97
Coal	9.94	10.09	12.27	10.09	13.21	10.09	14.22	13.08
Combustion Turbines	5.59	5.54	9.82	6.55	10.86	7.38	11.26	8.71
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Nuclear	3.82	3.82	3.82	3.82	3.01	3.01	1.68	1.68
Other Fossil Fuel	13.32	13.32	8.75	13.09	5.29	13.09	5.29	12.10
Pumped Storage	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Biomass[2]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**38.65**	**38.73**	**45.73**	**41.21**	**49.33**	**43.94**	**54.41**	**48.38**
Emissions								
NO_x (Thousand Short Tons)	219	226	174	226	166	229	169	230
Average Electricity Price (1997 Mills per Kilowatthour)	**63.7**	**61.8**	**65.7**	**62.4**	**62.3**	**62.9**	**60.3**	**58.4**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B10. Southeastern Electric Reliability Council (SERC) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**588**	**568**	**621**	**607**	**653**	**644**	**697**	**689**
Generation[1]								
Coal	391	422	378	435	416	437	449	478
Natural Gas	10	7	46	25	44	64	110	120
Petroleum	2	2	1	1	2	1	2	1
Hydro	38	38	38	38	38	38	38	38
Nuclear	192	186	189	185	171	167	103	101
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	1	2	2	2	2	3	2	3
Biomass[2]	11	5	17	10	15	16	17	15
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	1	1	2	2	2
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**645**	**661**	**670**	**697**	**688**	**726**	**722**	**757**
Capability (Gigawatts)[3]								
Combined Cycle	3.01	3.00	9.33	5.98	12.78	13.00	26.32	21.30
Coal	65.78	65.63	62.64	65.63	62.53	65.52	62.04	65.03
Combustion Turbines	13.15	13.14	21.07	21.01	25.22	28.56	33.83	35.43
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	11.87	11.87	11.93	11.93	11.93	11.93	11.93	11.93
Nuclear	25.47	25.58	24.71	24.83	21.34	21.46	13.44	13.56
Other Fossil Fuel	3.15	3.15	3.07	3.09	2.98	2.98	2.89	2.89
Pumped Storage	7.52	6.68	7.52	6.68	7.52	6.68	7.52	6.68
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.29	0.37	0.34	0.41	0.39	0.46	0.42	0.49
Biomass[2]	0.17	0.17	0.16	0.17	0.16	0.17	0.16	0.17
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.09	0.25	0.31	0.48	0.62	0.53
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**130.40**	**129.59**	**140.85**	**139.99**	**145.15**	**151.23**	**159.16**	**158.01**
Emissions								
NO_x (Thousand Short Tons)	808	889	585	791	645	802	705	847
Average Electricity Price (1997 Mills per Kilowatthour)	**50.4**	**57.4**	**51.8**	**55.1**	**51.1**	**50.8**	**50.7**	**49.1**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B11. Southwest Power Pool (SPP) Regional Electricity Results: CECA Competitive Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**289**	**285**	**305**	**303**	**321**	**322**	**342**	**342**
Generation[1]								
Coal	197	209	198	205	196	206	202	212
Natural Gas	33	24	47	45	51	46	59	54
Petroleum	1	2	0	0	0	0	0	0
Hydro	8	7	8	7	8	7	8	7
Nuclear	47	45	47	46	47	46	38	37
Geothermal	0	0	0	0	0	0	0	0
Municipal Solid Waste	0	0	0	1	0	1	0	1
Biomass[2]	6	1	11	7	11	6	6	2
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	0	6	14	24	29
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**295**	**290**	**311**	**310**	**321**	**327**	**341**	**342**
Capability (Gigawatts)[3]								
Combined Cycle	2.07	2.07	4.47	4.01	7.91	6.97	9.81	7.44
Coal	27.80	27.98	28.27	28.60	28.21	28.59	28.21	28.52
Combustion Turbines	5.15	5.15	7.82	6.99	10.17	8.86	15.05	10.53
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	2.81	2.84	2.81	2.84	2.81	2.84	2.81	2.84
Nuclear	6.05	5.93	6.05	5.93	6.05	5.93	4.27	4.16
Other Fossil Fuel	30.27	30.27	21.59	26.79	18.96	24.94	17.13	23.94
Pumped Storage	0.51	0.50	0.51	0.50	0.51	0.50	0.51	0.50
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.07	0.07	0.10	0.10	0.13	0.13	0.15	0.15
Biomass[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.01	0.00	2.41	4.77	9.74	9.54
Solar Photovoltaic	0.00	0.00	0.01	0.01	0.02	0.02	0.05	0.05
Total	**74.71**	**74.82**	**71.62**	**75.77**	**77.17**	**83.56**	**87.71**	**87.67**
Emissions								
NO_x (Thousand Short Tons)	446	465	413	439	382	411	384	416
Average Electricity Price (1997 Mills per Kilowatthour)	**51.8**	**53.5**	**52.6**	**51.8**	**50.6**	**47.6**	**49.1**	**48.0**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B12. Southwest Systems Coordinating Council/Rocky Mountain Power Area and Arizona (RA) Regional Electricity Results: CECA Competitive Cases
(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**136**	**115**	**151**	**129**	**167**	**142**	**182**	**156**
Generation[1]								
Coal	103	103	105	101	105	102	107	103
Natural Gas	7	25	11	32	9	31	21	29
Petroleum	0	0	0	0	0	0	0	0
Hydro	12	13	12	13	12	13	12	13
Nuclear	28	21	30	23	30	23	30	23
Geothermal	3	3	3	3	3	3	3	3
Municipal Solid Waste	0	0	0	0	0	1	0	1
Biomass[2]	2	0	6	2	6	1	3	1
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	5	6	19	13	20	16
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**157**	**165**	**171**	**181**	**183**	**188**	**196**	**189**
Capability (Gigawatts)[3]								
Combined Cycle	1.36	2.00	1.85	4.26	3.11	4.44	5.06	4.69
Coal	14.15	13.25	14.15	13.27	14.16	13.34	14.18	13.41
Combustion Turbines	2.58	4.31	3.70	4.61	4.44	6.87	6.23	7.05
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	3.98	3.98	3.98	3.98	3.98	3.98	3.98	3.98
Nuclear	3.81	2.99	3.81	2.99	3.81	2.99	3.81	2.99
Other Fossil Fuel	2.59	2.59	2.58	2.59	2.58	2.52	2.58	2.52
Pumped Storage	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72
Geothermal	0.35	0.31	0.35	0.32	0.36	0.34	0.40	0.38
Municipal Solid Waste	0.04	0.04	0.06	0.06	0.08	0.08	0.09	0.09
Biomass[2]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Thermal	0.02	0.02	0.06	0.06	0.06	0.06	0.07	0.07
Wind	0.08	0.06	1.95	1.86	6.42	3.62	7.06	4.27
Solar Photovoltaic	0.01	0.01	0.04	0.04	0.06	0.06	0.09	0.08
Total	**29.69**	**30.28**	**33.24**	**34.77**	**39.78**	**39.02**	**44.26**	**40.26**
Emissions								
NO_x (Thousand Short Tons)	226	236	230	227	219	218	219	215
Average Electricity Price (1997 Mills per Kilowatthour)	**52.2**	**75.9**	**58.7**	**70.5**	**52.8**	**63.1**	**53.1**	**59.3**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B13. Western Systems Coordinating Council/Northwest Power Pool (NWP) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**237**	**232**	**254**	**251**	**273**	**270**	**294**	**291**
Generation[1]								
Coal	84	87	81	86	81	87	84	89
Natural Gas	11	16	12	25	11	32	23	51
Petroleum	0	0	0	0	0	0	0	0
Hydro	153	164	152	163	159	163	162	163
Nuclear	7	7	8	8	9	8	0	0
Geothermal	1	1	2	4	3	7	5	10
Municipal Solid Waste	1	1	1	1	1	1	1	1
Biomass[2]	3	1	5	2	5	2	3	2
Solar Thermal	0	0	0	0	0	0	0	0
Wind	0	0	0	20	17	27	21	28
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**259**	**276**	**261**	**310**	**287**	**328**	**298**	**345**
Capability (Gigawatts)[3]								
Combined Cycle	1.88	2.26	1.88	3.69	1.94	4.41	3.56	6.99
Coal	11.37	11.58	11.37	11.60	11.37	11.67	11.37	11.88
Combustion Turbines	1.29	7.47	1.29	8.44	1.30	8.45	1.45	8.45
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	35.03	35.05	35.03	35.03	35.03	35.03	35.03	35.03
Nuclear	1.11	1.11	1.11	1.11	1.11	1.11	0.00	0.00
Other Fossil Fuel	0.72	0.72	0.47	0.72	0.42	0.72	0.42	0.72
Pumped Storage	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31
Geothermal	0.21	0.21	0.35	0.52	0.61	0.89	0.82	1.28
Municipal Solid Waste	0.11	0.11	0.13	0.13	0.17	0.17	0.19	0.19
Biomass[2]	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Solar Thermal	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02
Wind	0.03	0.03	0.03	5.83	7.98	7.68	10.17	7.98
Solar Photovoltaic	0.00	0.00	0.01	0.03	0.05	0.09	0.10	0.14
Total	**52.20**	**59.00**	**52.14**	**67.57**	**60.45**	**70.70**	**63.59**	**73.15**
Emissions								
NO_x (Thousand Short Tons)	172	176	167	174	160	171	161	178
Average Electricity Price (1997 Mills per Kilowatthour)	**39.2**	**49.1**	**40.5**	**48.1**	**38.4**	**45.0**	**38.9**	**43.2**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Table B14. Western Systems Coordinating Council/California-Southern Nevada Power (CNV) Regional Electricity Results: CECA Competitive Cases

(Billion Kilowatthours, Unless Otherwise Noted)

Demand, Generation, Capability, Emissions, and Prices	Projections							
	2000		2005		2010		2015	
	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS	DOE/ POEMS	EIA/ NEMS
Electricity Demand	**252**	**246**	**268**	**263**	**288**	**280**	**309**	**300**
Generation[1]								
Coal	32	44	35	43	48	47	72	54
Natural Gas	54	57	93	48	103	60	115	87
Petroleum	10	10	6	1	1	0	1	0
Hydro	40	45	40	45	40	45	40	45
Nuclear	34	39	34	40	34	40	34	40
Geothermal	12	10	13	10	14	10	13	9
Municipal Solid Waste	2	2	2	2	2	2	2	2
Biomass[2]	2	2	4	3	8	4	6	2
Solar Thermal	1	1	1	1	1	1	1	1
Wind	4	4	10	7	12	15	12	15
Solar Photovoltaic	0	0	0	0	0	0	0	0
Total	**191**	**214**	**237**	**201**	**262**	**223**	**296**	**256**
Capability (Gigawatts)[3]								
Combined Cycle	3.91	3.91	10.27	4.40	17.51	5.60	19.13	9.00
Coal	4.16	5.73	4.69	5.76	6.43	6.24	9.35	7.04
Combustion Turbines	4.82	4.83	4.68	5.52	4.96	6.97	5.98	9.43
Fuel Cells	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydro	11.33	11.33	11.33	11.33	11.33	11.33	11.33	11.33
Nuclear	4.31	5.13	4.31	5.13	4.31	5.13	4.31	5.13
Other Fossil Fuel	20.48	20.48	14.52	17.96	8.29	17.92	8.29	17.92
Pumped Storage	3.73	3.73	3.73	3.73	3.73	3.73	3.73	3.73
Geothermal	2.51	2.54	2.44	2.38	2.44	2.19	2.29	1.97
Municipal Solid Waste	0.36	0.36	0.37	0.36	0.37	0.36	0.37	0.36
Biomass[2]	0.37	0.37	0.37	0.37	0.88	0.37	0.90	0.37
Solar Thermal	0.35	0.35	0.36	0.36	0.37	0.37	0.39	0.38
Wind	1.95	1.96	4.22	2.94	4.84	4.96	4.84	4.96
Solar Photovoltaic	0.02	0.02	0.07	0.04	0.11	0.07	0.16	0.12
Total	**58.29**	**60.72**	**61.35**	**60.29**	**65.57**	**65.25**	**71.05**	**71.75**
Emissions								
NO_x (Thousand Short Tons)	78	102	69	94	51	97	52	108
Average Electricity Price (1997 Mills per Kilowatthour)	**77.0**	**74.9**	**77.8**	**73.3**	**69.7**	**71.2**	**68.0**	**69.5**

[1]Excludes traditional cogenerators and firm imports.
[2]Includes co-firing as well as direct combustion.
[3]Includes nontraditional cogenerators.
NO_x = Nitrogen oxide.
Sources: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999), and Energy Information Administration, National Energy Modeling System run CECACMP2.D082899A.

Appendix C

Detailed NEMS Assumptions for the CECA Competitive Case

Appendix C

Detailed NEMS Assumptions for the CECA Competitive Case

This appendix contains detailed tables providing the values for the assumptions discussed in Chapter 2. A brief discussion is also provided for each table. For more detailed information on what the values mean and how they are used, please refer to the NEMS electricity model documentation available on EIA's web site at http://www.eia.doe.gov/bookshelf/docs.html.

Cost of Capital

Table C1 gives the cost of capital values used in capacity expansion decisions. The capital costs for all new plants are assumed to be recovered over 20 years.

Table C1. Cost of Capital
(Percent)

Assumption	Utilities	Exempt Wholesale Generators
	CECA Reference Case	
Debt Fraction	0.49-0.661	0.65
Return on Debt	0.10	0.08
Return on Equity	0.10-0.142	0.16
	CECA Competitive Case	
Debt Fraction	0.49-0.661	0.60
Return on Debt	0.10	0.08
Return on Equity	0.10-0.142	0.18

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Annual Renewable Portfolio Share Required

Table C2 gives the annual nonhydroelectric renewable portfolio standard requirement in the CECA Competitive case for the years 2000 to 2020. The shares used are equivalent to those used in the *Supporting Analysis*, which increase more rapidly between 2000 and 2005 than is required in the proposed Comprehensive Electricity Competition Act.

Table C2. Annual Nonhydroelectric Renewable Portfolio Share
(Percent)

Year	Share	Year	Share
2000	2.2	2006	6.1
2001	4.2	2007	6.4
2002	4.7	2008	6.7
2003	5.1	2009	7.1
2004	5.5	2010-2015	7.5
2005	5.8		

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Plant Outage Improvements

Table C3 gives a description of the plant types. Table C4 shows the planned and forced outage rates, capacity credit and maximum capacity factors used for each plant type in the CECA Reference and Competitive cases.

Table C3. Plant Types

Plant Type	Plant Type Name
XL	Unscrubbed Coal Steam: Low Sulfur
XM	Unscrubbed Coal Steam: Medium Sulfur
XH	Unscrubbed Coal Steam: High Sulfur
SE	Existing Scrubbed Coal
SR	Retrofit Scrubbed Coal
PC	New Scrubbed Pulverized Coal
IG	Advanced Coal (IGCC)
IS	Advanced Coal with Sequestration
ST	Oil/Gas Steam
ET	Existing Turbine
CT	New Combustion Turbine
AT	New Advanced Turbine
EC	Existing Oil/Gas Combined Cycle
CC	New Combined Cycle
AC	New Advanced Combined Cycle
CS	New Advanced CC with Sequestration
FC	Fuel Cell
CN	Nuclear
AN	Advanced Nuclear
WD	Biomass / Wood
MS	Municipal Solid Waste

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Table C4. Plant Outage Rates
(Percent)

Plant Type	CECA Reference Case				CECA Competitive Case			
	Forced Outage Rate	Planned Outage Rate	Capacity Credit	Maximum Capacity Factor	Forced Outage Rate	Planned Outage Rate	Capacity Credit	Maximum Capacity Factor
XL	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
XM	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
XH	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
SE	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
SR	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
PC	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
IG	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
IS	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
ST	6.00	10.10	100.00	84.60	3.90	7.60	100.00	88.80
ET	3.60	4.10	100.00	92.40	3.60	4.10	100.00	92.40
CT	3.60	4.10	100.00	92.40	3.60	4.10	100.00	92.40
AT	3.60	4.10	100.00	92.40	3.60	4.10	100.00	92.40
EC	5.50	4.10	100.00	90.60	5.50	4.10	100.00	90.60
CC	5.50	4.10	100.00	90.60	5.50	4.10	100.00	90.60
AC	5.50	4.10	100.00	90.60	5.50	4.10	100.00	90.60
CS	5.50	4.10	100.00	90.60	5.50	4.10	100.00	90.60
FC	7.40	1.90	100.00	87.00	7.40	1.90	100.00	87.00
CN	8.20	11.50	100.00	80.00	8.20	11.50	100.00	80.00
AN	3.80	6.10	100.00	85.00	3.80	6.10	100.00	85.00
WD	0.00	8.20	80.00	80.00	0.00	8.20	80.00	80.00
MS	0.00	0.00	78.00	78.00	0.00	0.00	78.00	78.00

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Plant Heatrate Improvements

Table C5 gives the assumed target heatrates from the *Supporting Analysis* used in the NEMS CECA Competitive case. In the *Supporting Analysis* each existing plant was assumed to improve toward the target for its plant group. The improvement occurs over the period 1998 to 2010. Each plant (or plant group) is assumed to improve by 60 percent of the difference between its current heatrate and its group target. To put these values in context, the current average heatrates for coal plants falling into the Coal Steam Pre-1965 category is 12,128 Btu per kilowatthour. As a result, the 10,300 Btu per kilowatthour target is 15 percent below the current average.

Table C5. Heatrate Targets
(Btu per Kilowatthour)

Plant Type (NEMS Acronym and Name)	Target Heatrate
COU: Coal Steam pre 1965	10,300
CSU: Coal Steam post-1965	9,500
CSC: Coal Steam with Scrubber	9,500
CNC: New Coal Steam	9,600
CAV: New Advanced Coal	9,600
CAS: New Advanced Coal with Sequestration	9,600
STO: Oil Steam	11,000
STG: Gas Steam	11,000
STX: Oil/Gas Steam	11,000
CTO: Oil Turbine	12,500
CTG: Gas Turbine	12,500
CTX: Oil/Gas Turbine	12,500
ACT: Advanced Turbine	12,500
CCO: Oil Combined Cycle	9,000
CCG: Gas Combined Cycle	9,000
CCX: Oil/Gas Combined Cycle	9,000
ACC: Advanced Combined Cycle	9,000
ACS: Advanced Combined Cycle With Sequestration	9,000
FCG: Fuel Cell	9,000

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Plant Operations and Maintenance Cost Improvements

Table C6 gives the targets for fixed operation and maintenance costs from the *Supporting Analysis* that were used in the NEMS CECA Competitive case. The improvement occurs over the period 1998 to 2010. Each plant (or plant group) is assumed to improve by a percentage (given in the “Percent to Target” column below) of the difference between its current heatrate and its group target.

Table C6. Fixed Operations and Maintenance Cost
(1987 Dollars per Kilowatt per Year)

Plant Type (NEMS Acronym and Name)	Fixed O&M Target	Percent to Target
COU: Coal Steam pre 1965	12	75
CSU: Coal Steam post-1965	12	75
CSC: Coal Steam with Scrubber	12	75
CNC: New Coal Steam	12	75
CAV: New Advanced Coal	12	75
CAS: New Advanced Coal with Sequestration	12	75
STO: Oil Steam	6	50
STG: Gas Steam	6	50
STX: Oil/Gas Steam	6	50
CTO: Oil Turbine	2	50
CTG: Gas Turbine	2	50
CTX: Oil/Gas Turbine	2	50
ACT: Advanced Turbine	2	50
CCO: Oil Combined Cycle	4	90
CCG: Gas Combined Cycle	4	90
CCX: Oil/Gas Combined Cycle	4	90
ACC: Advanced Combined Cycle	4	90
ACS: Advanced Combined Cycle With Sequestration	4	90
FCG: Fuel Cell	4	90
CNU: Conventional Nuclear	50	75
ANC: Advanced Nuclear	50	75

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Transmission and Distribution Service Cost Improvements

Table C7 provides the factors used to adjust transmission and distribution services to match the cost improvements assumed in the *Supporting Analysis.* These factors were incorporated in the NEMS CECA Competitive case.

Table C7. Transmission and Distribution Service Cost Adjustment Factors

Year	Transmission	Distribution
2000	1.000	1.000
2001	0.993	0.985
2002	0.985	0.971
2003	0.978	0.956
2004	0.971	0.942
2005	0.963	0.928
2006	0.956	0.914
2007	0.949	0.901
2008	0.942	0.888
2009	0.935	0.875
2010-2015	0.928	0.862

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Demand Reductions From Energy Efficiency Investments

Table C8 provides the electricity demand reductions assumed in the *Supporting Analysis* and incorporated in the NEMS CECA Competitive case. These result from investments in energy efficiency using the CECA Federal Public Benefits Fund.

Table C8. Energy Efficiency Demand Savings
(Billion Kilowatthours)

Year	Residential Sector	Commercial Sector	Industrial Sector	Total
2000	2.9	4.5	3.2	**10.7**
2001	6.1	9.4	6.7	**22.2**
2002	9.4	14.3	10.1	**33.7**
2003	12.6	19.1	13.6	**45.2**
2004	15.8	24.0	17.0	**56.8**
2005	19.0	28.9	20.5	**68.3**
2006	23.0	35.8	25.3	**84.1**
2007	27.1	42.7	30.1	**99.8**
2008	31.2	49.6	34.9	**115.6**
2009	35.2	56.5	39.7	**131.4**
2010	39.3	63.4	44.5	**147.2**
2011	39.9	64.3	45.0	**149.2**
2012	40.6	65.1	45.5	**151.1**
2013	41.2	66.0	46.0	**153.1**
2014	41.8	66.8	46.5	**155.1**
2015	42.4	67.7	47.0	**157.1**

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Cogeneration

Tables C9 and C10 provide the incremental cogeneration assumed in the *Supporting Analysis* and incorporated in the NEMS CECA Competitive case.

Table C9. Incremental Commercial Sector Cogeneration
(Billion Kilowatthours)

Fuel	2000	2005	2010	2015
Natural Gas	0.4	4.1	24.1	27.9
Distillate	0.1	0.7	3.9	4.5
Residual Oil	0.0	0.0	0.0	0.0
LPG	0.0	0.0	0.0	0.0
Coal	0.2	1.6	9.3	10.8
MSW	0.1	0.5	2.9	3.4
Total	**0.7**	**6.8**	**40.2**	**46.6**

Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Table C10. Incremental Industrial Sector Cogeneration
(Billion Kilowatthours)

Type	2000	2005	2010	2015
Sales to Grid	0.6	4.8	11.7	14.9
Own Use	3.1	23.9	58.0	74.6
Total	**3.7**	**28.8**	**69.7**	**89.5**

Note: All incremental industrial sector cogeneration is assumed to be gas fired.
Source: U.S. Department of Energy, *Supporting Analysis for the Comprehensive Electricity Competition Act*, DOE/PO-0059 (Washington, DC, May 1999).

Appendix D

NEMS/EMM Model Changes From *AEO99*

Appendix D
NEMS/EMM Model Changes From *AEO99*

This appendix discusses enhancements to the Electricity Market Module (EMM) of NEMS that were used in this study but made after completion of the *Annual Energy Outlook 1999* in 1998. The key changes involve revisions to the electricity dispatching algorithm, the methodology used to estimate sales growth for capacity planning decisions (demand foresight), and the representation of biomass co-firing. Two of these changes, those for demand foresight and biomass co-firing, were made to represent the assumptions of CECA. The revised dispatching algorithm is an enhancement to the model unrelated to CECA. Testing during its development produced results similar to those for the previous algorithm, with slightly higher interregional trades.

Electricity Dispatch

The Electricity Fuel Dispatch (EFD) submodule determines how to utilize (dispatch) existing generating capacity to meet the demand for electricity at the lowest cost. In the *AEO99* version of the EMM, this task was accomplished using a heuristic algorithm which started by ordering plants from lowest to highest cost (typically referred to as merit order) in each region. From the merit order the algorithm chose the capacity needed to meet each region's needs for each season and time of day. After this initial dispatch, the model then compared the costs of unused capacity in contiguous regions to evaluate whether it would be economical to trade power between the regions. If so, the initial dispatch was revised to take advantage of the interregional trade opportunity, subject to transmission constraints. This process has been replaced by an integrated linear programming algorithm that makes dispatch and trading decisions simultaneously.

The linear program provides a least-cost solution for all regions simultaneously, given fuel prices, plant availabilities, and interregional transmission constraints. Whereas the previous model solved for each region independently, the linear program provides unique solutions for all NERC regions and each of the 108 time slices. Certain technologies, such as hydroelectric power, solar thermal and photovoltaic power are not merit-order dispatched and are treated outside the linear programming structure by assuming they operate at a fixed capacity factor. The replacement of the heuristic algorithm with a linear program was done to improve the model's representation of competitive electricity markets, allowing multiregion power trades where they are economical.

Demand Foresight

Before making decisions about how much and what type of new capacity to build, the Electricity Capacity Planning (ECP) submodule of the EMM needs an estimate of what consumers' demand for electricity will be in the future. The demand growth projections—often referred to as demand foresight—together with fuel price and generating technology cost and performance information, are critical in capacity planning decisions. In *AEO99*, future demand growth expectations were based on the average growth over the previous 3 years. This algorithm tended to yield somewhat volatile projections, because the use of electricity in any given year—or short period of years—can be dramatically affected by weather and business cycles. For example, a mild weather year followed by 2 years of normal or warmer than normal weather together with strong economic growth could lead to unrealistically high demand growth projections in the ECP. This algorithm has been revised to provide a smoother trajectory in the years immediately following the historical period. The demand foresight algorithm now uses exponential smoothing of the previous period's growth rates to create a growth rate for the planning horizon. An average historical growth rate was chosen, rather than the actual value derived from the year-to-year variation in demand.

Biomass Co-firing

In the *AEO99*, NEMS did not have the ability to allow coal plants to choose to co-fire with biomass fuel if it was economical. Several studies have reported that coal plants can burn a small amount (typically a few percent of their total fuel input) of biomass in place of coal without having to make significant capital expenditures. In addition, several bills in the Congress include incentives to encourage biomass co-firing in coal plants. As a result, the capability to represent biomass co-firing has been added to both the ECP and EFD submodules. Co-firing coal plants with biomass is now an additional option available in the ECP. The biomass fuel share chosen by the ECP is communicated to the EFD, and for those units dispatched, the fuel choice is adjusted accordingly.

Appendix E

Service Request Memorandum

The Secretary of Energy
Washington, DC 20585

June 24, 1999

MEMORANDUM FOR JAY HAKES, ADMINISTRATOR
ENERGY INFORMATION ADMINISTRATION

FROM: BILL RICHARDSON

Subject: Request for Electricity Restructuring Study

With increasing attention focused on the issue of electricity restructuring in both the Administration and the Congress, assessments of the projected impacts of competition will play an important role in ongoing discussions. The Department has already provided Congress with its *Supporting Analysis*, which outlines the likely benefits of competition for the economy, consumers, and the environment under the Administration's proposal. This analysis relies on many assumptions found in the Energy Information Administration's (EIA) *Annual Energy Outlook 1999*. It was developed using the Policy Office Electricity Modeling System (POEMS), which combines major sections of the EIA National Energy Modeling System (NEMS) with a more detailed representation of the electricity sector than is included in the standard NEMS model.

Notwithstanding our high level of confidence in the results presented in the *Supporting Analysis* document, a parallel analysis using the standard NEMS could provide further evidence regarding the benefits of competition under the Administration's plan. Accordingly, I am requesting that you use the NEMS to evaluate the effects of the Administration's restructuring proposal using the parameter settings and assumptions from the POEMS analysis. Your report should also include a discussion of major differences between the electricity modules of the POEMS and the NEMS. Please consult directly with Mark Mazur, Acting Director of Policy, regarding the appropriate parameters for the Reference and Competitive scenarios, as well as the types of topics to be addressed in the comparison of the POEMS and NEMS electricity modules.

Given that electricity restructuring is currently under active consideration, I am requesting that your draft report be provided to the Policy Office by the first week of September 1999. A reduction in the scope of your report may be preferable to any significant delay in meeting this timetable This issue should be included in your discussions with the Policy Office if sufficient resources to provide a full and timely response are not available.

Thank you for your prompt attention to this request I am looking forward to receiving your report on this important subject

Department of Energy
Washington, DC 20585

August 18, 1999

TO: Mary Hutzler
Director, Office of Integrated Analysis and Forecasting

FROM: Howard Gruenspecht
Director, Office of Economic, Electricity, and Natural Gas Analysis

SUBJECT: Additional Information on *Supporting Analysis* Assumptions

This memorandum provides additional information regarding the assumptions used in the *Supporting Analysis for the Comprehensive Electricity Competition Act* that was published in May 1999. You had asked for this information to support your efforts to provide an analysis of the impacts of competition requested by Secretary Richardson, who asked that you use the National Energy Modeling System (NEMS) together with the parameter settings and assumptions from the modeling results presented in the *Supporting Analysis*.

Additional Information on Assumptions Used In the *Supporting Analysis*

1. Treatment of Operation and Maintenance (O&M) Costs for new units

The POEMS model results presented in the *Supporting Analysis* use O&M costs for new generating units that are below the levels assumed in the 1999 Annual Energy Outlook. This change, which applies to both the Reference and Competitive scenarios, assures that the O&M cost for new units is not assumed to be higher than the O&M target improvement levels for existing plants established through a benchmarking analysis of existing plants. While these target levels necessarily have wide uncertainty for technologies where the number of existing plants is small (i.e. combined cycle gas plants) we feel that our approach retains a plausible relationship between new and existing plant O&M costs for all technology types. In addition, we used relatively conservative assumptions about bidding strategy, by including 50% of the total annual O&M in the competitive bid price. Finally, we use the same O&M parameters for new units in both the Reference and Competitive scenarios, so that their impact is reflected in both of the cases whose difference is examined.

2. Demand foresight

The POEMS analysis incorporates a revised foresight algorithm which smoothes near term expectations of demand growth. We feel that this approach is appropriate for the purposes of capacity planning in both the Reference and Competitive cases, since capacity decisions involve long-lived capital.

3. Ancillary payments for capacity

As of yet, there are not clear indications how deregulated markets will value capacity, as distinct from energy. Various states have taken different approaches. The *Supporting Analysis* assumes an institutional structure in the Competitive scenario that provides payments to build capacity necessary to meet specified reserve margins in those regions where energy markets alone would not provide a sufficient incentive. In part because of the POEMS modeling structure, capacity for reserve purposes may not compensated sufficiently through high prices that might occur when random events cause extremely high peaks and short capacity. The payments included in the Competitive scenario are designed to insure that new necessary capacity is made whole and that customers are charged appropriately for this function. The payments are targeted to turbine and combined-cycle plants to preclude a windfall to existing baseload plants.

4. Existing powerplant O&M and post-operational capital expenditures.

We have compared the average fixed plus variable O&M costs by plant type in POEMS and NEMS and found them to be very similar. There are some differences in the post-operational capital expenditures, because they are represented at a more disaggregated level in the POEMS than those used in the AEO99. The use of plant-specific capital addition costs should lead to better identification of economic plant retirements, but would affect the Reference and Competitive scenarios in the same manner. Because the two models represent the same underlying cost structure for each plant type, analysis using the existing NEMS data should provide a sufficient degree of parallelism to meet the Secretary's request.

5. Biomass (cofiring and production tax credit) and wind incentives.

The *Supporting Analysis* references inclusion of the co-firing and production tax credits that are outlined in the Administration FY2000 budget proposal. These proposals extend and expand a credit regime established in the 1992 Energy Policy Act. The Supporting Analysis assumes that these credits, which are proposed for extension through 2004 in the FY2000 budget proposal, would be further extended through 2015 through subsequent action.

6. Retirement cost hurdle for nuclear plants

A retirement hurdle rate was incorporated in POEMS for nuclear plants in the Reference scenario to represent the hesitancy of utilities in retiring plants before the end of their licenses because of risks associated with the costs of decommissioning and cost recovery. We think it is appropriate to draw a distinction between the strength of the economic factors in driving retirement decisions for this technology between the Reference and Competitive scenarios.

7. Firm Sales Between Regions

Available information on firm sales does not extend through the forecast horizon. Because agreements for firm sales will likely be negotiated or renegotiated on an economic basis as existing contracts expire, the POEMS analysis does not "force" firm sales to be maintained indefinitely beyond the last data point. However, an assumption that all pre-specified firm sales contracts were to lapse simultaneously at the point where our data runs out would also be unrealistic and distort decisions in the capacity planning module of the model by creating a large discontinuity at a single point in time. The POEMS analysis assumed a gradual phase-out of pre-specified firm sales.

8. Renewable Energy

Under the Administration's restructuring proposal, the level of the renewable portfolio standard (RPS) target expressed as a percentage of sales for years prior to 2010 is to be set through a rulemaking process. The Administration proposal also explicitly allows for banking of renewable energy credits, so that excess credits from renewable generation in one year can be carried forward to satisfy the RPS requirement in a future year. For these reasons, the POEMS analysis does not impose a "cap" on renewable electricity production along a straight-line path between its projected level in 2000 and the 2010 target level of 7.5 percent of retail sales.

The *Supporting Analysis* also notes that some consumers in Competitive markets will choose to purchase "green power" at a cost exceeding the 1.5 cent per kilowatt-hour cost cap applied in the RPS program. We allow for this demand, which in our results equals 0.3 percent of retail electric sales in 2010, by relaxing the cost cap in the capacity planning module.

Further Observations

We recognize that even when the assumptions documented in the *Supporting Analysis*, as clarified by the points listed above, are reflected in the NEMS model, there will still be a number of differences in assumptions between NEMS and POEMS. Indeed, because of differences in model structure and level of detail, there can never be exact comparability across models. For example, POEMS and NEMS handle intra-regional transmission constraints and opportunities for economic interchanges in a different manner. Also, POEMS does not calibrate to the Short-term Energy Outlook while EIA uses such a calibration in its default implementation of NEMS. In addition, POEMS as implemented in the Supporting Analysis, did not impose a retirement hurdle rate for fossil power plants, while NEMS has traditionally used such a rate, together with limits on "overbuilding," to significantly limit displacement of existing generating assets for economic reasons.

Notwithstanding the lack of complete congruence, we feel that incorporation of the assumptions documented in the *Supporting Analysis*, as supplemented by our previous communications and the numbered points outlined above, would provide an appropriate basis for carrying out the parallel analysis. It is not necessary or feasible to turn NEMS into POEMS.

Of course, the ultimate decision regarding changes in NEMS assumptions to be made in response to the Secretary's request rests with EIA. However, whatever your decision in this regard, we would strongly suggest that any changes that EIA makes in NEMS assumptions and/or model structure from those used in the 1999 Annual Energy Outlook (AEO99) be thoroughly documented in your report. As noted in the memorandum from the Secretary requesting that EIA undertake this project, the *Supporting Analysis* relies heavily on AEO99. The results of your parallel analysis will necessarily reflect changes in NEMS since AEO99 as well as the assumptions and parameters that are documented in the *Supporting Analysis* and this memorandum. For this reason, documentation of all changes since AEO99, many of which may be completely independent of the *Supporting Analysis*, will be essential to users of your analysis in understanding your results.