Chapter 7

THE ELECTRICITY SECTOR[1]

7.1 INTRODUCTION

7.1.1 Overview of the Electric Sector

In 1997, the generation of electricity in the U.S. consumed the equivalent of 34 quads of primary energy, or 36% of all the energy used in the U.S. Of this, 23 quads was provided by fossil fuels, with 18.6 quads from coal, 3.4 from natural gas and 0.9 from petroleum. This fossil fuel use produced 532 million metric tonnes of carbon (MtC), 11.6 million metric tons of sulfur dioxide emissions, and 5.3 million metric tons of nitrogen oxide emissions. These values do not include the contributions from cogeneration, which would raise the values even higher.

There are essentially four mechanisms to reducing the impact of the electric sector in these areas. These include:

- reducing the demand for electricity,
- increasing the efficiency of individual fossil-fired power plants and transmission,
- reducing or sequestering the emissions from these plants, and
- switching to less- or non-carbon intensive sources of generation.

Significant opportunities exist to reduce the demand for electricity. These opportunities are addressed in the end-use chapters of this report. This chapter will focus on the other three mechanisms and the policies that could affect them.

7.1.2 Restructuring of the U.S. Electric Sector

Identification and evaluation of policy pathways to reduce emissions in the electric sector is both facilitated and complicated by the current restructuring of the sector. The U.S. electricity industry is being transformed from a highly-regulated, vertically-integrated, industry to a largely competitive deintegrated industry, at least in the generation sector. Transmission and distribution functions are expected to remain largely cost-of-service regulated. Because this transformation is far from complete, it is difficult to predict the structure the sector will possess in the future, much less the impact that alternative policies could have on these characteristics.

Clearly, the set of players will expand from the historical set of utilities and regulators to include distribution companies, independent system operators, generation companies, power brokers, energy service companies, etc. The decisions made by the profit-maximizing owners of individual generating units are likely to be quite different than the system-wide cost-minimizing decisions made in the past by utility owners of large generation and transmission systems and the respective public utility commissions. In unregulated markets characterized by short-term matching of offers to sell electricity with demand for electricity, and without guaranteed returns, investors in generation will evaluate opportunities on a shorter time scale with risk considered largely through higher costs of capital, and returns based on marginal pricing. Separate ownership or control of generation and transmission systems under different forms of

[1] Authors: Stanton W. Hadley, Oak Ridge National Laboratory (ORNL); Walter Short, National Renewable Energy Laboratory (NREL); David South, Energy Resources International; Lowell Reid and Michael Sale, ORNL.

economic regulation, risk, and reward, may create a different system structure than one where both components have prices regulated.

There already has been a reduction in R&D efforts and demand-side management programs by utilities preparing for the competitive environment. Some utilities are also divesting themselves of generation assets and becoming regulated transmission/distribution companies providing open access to all generators as mandated by the Federal Energy Regulatory Commission (FERC) in response to the 1992 Energy Policy Act. Finally, states are beginning to mandate such restructuring; the Clinton Administration is pushing legislation to facilitate it; and consumers are beginning to express preferences not only for low-cost power, but for environmentally-clean power.

Other factors are also forcing the U.S. electricity industry to change. These factors include low natural gas prices, substantial improvements in the efficiency of gas-fired combustion turbines and combined cycle systems, broad public sentiment favoring deregulation of economic sectors wherever possible, and heightened interest and concern for the environment and its protection.

7.1.3 Technology Opportunities

Policies and market structure do not generate emissions or consume imported oil, technologies do. Thus, policies put forth in the hope of meeting national goals are intended to encourage the use of “clean energy” technologies. Table 7.1 summarizes these technology opportunities for the electric sector along with issues that may stall their development. Because of the age of the current fleet of power plants (2/3 were built before 1970), there is a great opportunity for these new, more efficient technologies to be deployed as existing plants are retired and replaced. Combined heat and power or cogeneration plants are not shown in Table 7.1 since they are treated in the buildings and industry end-use chapters of this report.

Table 7.1 Electric Sector Technology Opportunities

Technology	1997 gen market share	1997 avg. grams carbon / kWh	Possible future improvement	Issues/comments
Coal boilers	56%	260	New plant efficiency could be as high as a third greater than the efficiency of existing plants Existing plant efficiency could be improved but to a lesser extent Carbon sequestration	Few new coal plants are currently planned Existing plants are cheapest source of fossil power Refurbishments are costly Depending on pending environmental constraints, older plants may be retired Seq. in early research stage
Coal IGCC	~0	210	Possible combination with fuel cell yields high efficiency and carbon separation achieving near zero carbon and criteria air pollutant emissions	Close to commercial 3 commercial demonstration plants operating in U.S.
Gas Turbine	<5%	170	New plant efficiency >40% efficiency; current plants ≈32%	Largely peak load (with some intermediate), thus has lower impact on total emissions

Technology	1997 gen market share	1997 avg. grams carbon / kWh	Possible future improvement	Issues/comments
Gas combined cycle	<4%	100	Market share can be substantially increased over time New plant efficiencies could increase to 60% to 70% with a ternary cycle; current models are 43% –57% efficient With carbon separation could achieve near zero carbon	Designed for intermediate and base load; could replace retiring coal plants and inefficient gas plants Large resource base Fuel deliverability and cost may become issue in future
Fuel cells	0%	>=0 depending on fuel source	Can be combined with other cycles With carbon separation could achieve carbon and criteria air pollutant emissions near zero	First cost needs to be reduced further Technology improvements needed
Nuclear	20%	0	Improved efficiency and life extension of current plants possible at low cost New small plants may better meet market needs	Public concern with safety Spent fuel storage and disposal could limit future operations More than 50% of plants require license renewal by 2020
Hydro	10%	0	Increased efficiency and enhanced environmental performance with advanced technology	Large potential (60 GW) Concerns with environ-mental impacts from public and natural resource management agencies
Wind	<1%	0	Costs competitive on kWh basis in near future in some markets	1998 growth rate of 35% worldwide Intermittency may limit role
Biomass cofiring	<1%	~0 for biomass portion	Use can be increased relatively easily to 2 – 4 % of coal generation	Requires biomass collection infrastructure; negligible coal plant retrofits required at low levels of biomass to coal.
Geothermal Hydrothermal	<1%	0	Resource identification	Competitive today at good resource site; resources limited
Photovoltaics	0	0	75% cost reductions possible in long term (EPRI, 1997)	Large 2020 potential in buildings assuming net metering
Solar thermal	<1%	0	Limited cost-reduction potential	Only southwestern U.S.

7.2 POLICY IMPLEMENTATION PATHWAYS

Deployment of these "clean energy technologies" can be accelerated by overcoming market barriers and failures through policy interventions. For the BAU scenario, no policies beyond those currently in place are assumed, consistent with the EIA's assumptions in AEO99. Policies evaluated as part of the Moderate and Advanced scenarios are shown in Table 7.2. A brief description of each follows the table with specific parameter values in Appendix C-4. In addition, other policies that may be useful but could not be accurately modeled quantitatively in CEF-NEMS are discussed in Section 7.2.2. Some sensitivities to the scenarios were run that modified the below policies or added approximations of other policies. These are discussed in Section 7.5.3.

Table 7.2 Electricity Policy Pathways Analyzed

Moderate Scenario	Advanced Scenario
➢ 1.5¢/kWh production tax credit (PTC) for wind and biomass power to 2004. 1.0¢/kWh credit for biomass cofiring.	➢ Same, for all non-hydro renewable electricity options to 2004.
	➢ Renewable Portfolio Standard – represented by 1.5¢/kWh PTC in 2005-2008 to model cap in administration proposal
➢ Wind deployment facilitation	➢ Same
➢ Enhanced R&D – represented by the electric technology cost and performance of the AEO99 high renewables and high fossil cases	➢ Additional technology advances beyond those of the Moderate scenario ➢ Include sequestration option.
➢ Up to 1% net metering.	➢ Up to 5% net metering.
➢ Full national restructuring in 2008.	➢ Same.
	➢ SO_2 ceiling reduced in steps by 50% between 2010 and 2020 to represent tighter PM standards
	➢ Carbon cap with assumed consequent permit price of $50 per metric ton of carbon, starting in 2002 with full value by 2005.

7.2.1 Policy Pathways Quantitatively Analyzed

Production tax credit. In the Advanced scenario, a production tax credit of 1.5¢/kWh (1992$) is assumed for the first 10 years of operation from all non-hydro renewable electric generators installed through 2004. The tax credits lower the cost of production; the additional cost to the Treasury is discussed in section 7.5.4. In the Moderate scenario, only wind and biomass power qualify, consistent with the

President's Climate Change Technology Initiative proposals. In addition, for both scenarios a 1¢/kWh credit is given for cofired biomass during the years 2000-2004.

Renewable Portfolio Standard (RPS). The President's proposed (April 1999) legislation on competition in the electric sector includes a mandate to generate 7.5% of all electricity sales from either wind, biomass, solar, or geothermal for the years 2010 through 2015. However, a 1.5¢/kWh cap on the price premium for the renewable power is established. If the price difference between renewable energy and other alternatives is more than the cap, then it could come into play and lower the portfolio percentage which could end up less than 7.5%. Although CEF-NEMS has the capability to include an RPS, it cannot directly model the 1.5 cents/kWh cap and it has problems combining RPS with marginal-cost-based rates. As a surrogate to the CEF-NEMS method of modeling the RPS, we extended the PTC of 1.5¢/kWh to capacity added between 2005 and 2008. Because the biomass cofiring tax credit only applies in the years specified, as opposed to the following ten years, it was extended to 2014. We calculated the added cost and carbon saved due to the tax credit extension and determined it to be between \$60 and \$70/tC. For this reason, the credit was only applied in the Advanced scenario.

Policies to facilitate wind deployment. There are a number of issues associated with wind deployment and operation within a competitive electric market that could be mitigated through focussed policies. These include policies to facilitate siting on Federal land (for example, reducing the National Environmental Protection Act (NEPA) filing requirements which currently require avian, archeological, and flora/fauna studies), to expedite challenge procedures and limit liabilities for all sites (for example, there is concern that criminal charges could be pressed for the death of any endangered avian species), to design independent system operator protocols to accommodate wind intermittency (for example, the establishment of a trading market to firm up intermittent power sources), etc[2].

Enhanced R&D. Federal R&D budgets for renewable, nuclear, and fossil generation technologies are assumed to increase 50% in the Moderate scenario, and 100% in the Advanced scenario. The Moderate scenario funding increases together with industry learning are assumed to yield technology cost and performance equal to that of the EIA's high renewables and high fossil cases defined in EIA's 1999 Annual Energy Outlook (EIA, 1998a). EIA states in the AEO99 that the values used for the high fossil cases in the AEO99 were chosen "to reflect potential improvements in costs and efficiencies as a result of accelerated research and development." However, in recent comments they have said that these were simple sensitivities only loosely reflective of enhanced R&D. The improved renewable technology values were based on "more optimistic Department of Energy renewable energy assumptions" (EIA, 1998a). These renewable assumptions are consistent with the EPRI/DOE Renewable Energy Technology Characterizations report (EPRI, 1997). In the Advanced scenario, the renewable technology cost and performance assumptions remained the same as those in the Moderate scenario, while the fossil generator data were based on information received from the DOE Office of Fossil Energy, consistent with their Vision 21 performance goals (DOE/FE, 1999; Parsons, 1998; Dye, 1999). Because the amount of improvement due to R&D is not assured, sensitivities were done using less optimistic advances in the fossil and renewable technologies. These are discussed in section 7.5.3.

The capital cost of the advanced gas combined cycle (AGCC) is the same in the Advanced scenario as in the Moderate scenario. The efficiencies are the same for all scenarios in 2000 but gradually improve more rapidly and to a higher value in the Advanced scenario to reflect extra effort on improvements through R&D. One source of improvement is the addition of a fuel cell to the front of the AGCC, creating a

[2] To reflect these policies, changes were made to the model's parameters for all three scenarios, including the BAU. However, the changes did not affect the BAU scenario because the constraints on wind capacity caused by these parameters were not limiting its growth. Consequently, these changes can be thought to apply only to the Moderate and Advanced scenarios.

ternary cycle. This does not begin to penetrate the AGCC market until post-2005. AGCC efficiencies are at 55% in 2005 in the Advanced scenario and improve to 70% by 2015 while in the moderate and BAU scenarios, the AGCC efficiency peaks at approximately 55% in 2010.

The advanced nuclear technology was modified for the Moderate and Advanced scenarios. In the Moderate scenario, the fifth-of-a-kind cost of advanced nuclear technology was kept the same as in the BAU (and AEO99 reference) case, but to reflect a policy that the advanced nuclear plants would be jointly developed with international partners, the cost of the initial plants were not increased as much[3]. In the Advanced scenario, the capital cost of the advanced nuclear was reduced by roughly 10% to represent reductions in construction costs through advanced designs and R&D. Sensitivities were run on the Advanced scenario that further lowered the cost of the initial nuclear plants by subsidizing the capital cost premium of these plants over the fifth-of-a-kind plant cost. These are discussed in section 7.5.3.

Specific correlations between R&D amounts and technology improvements were not used in this study. Rather, recognized technology targets by experts were used to establish the potential improvements with higher improvements assumed with increased funding. More precise technology achievements as a function of research funding over a long time period are difficult if not impossible to attain. The costs and efficiencies of the fossil, nuclear, and renewable plants are listed in Appendix C-4.

Net metering. Consistent with the President’s recently (4/19/99) proposed legislation on competition in the electric sector (DOE, 1999), this policy assumes a minimal level of net metering is allowed by the states. It is applicable only to systems of 20 kW or less in residential and commercial applications. Net metering means that on-site generation exceeding site loads can be fed back to the grid at values equal to the purchase price, i.e. the meter can be run “backwards” when on-site generation exceeds on-site loads. Net metering creates incentives for distributed generation which can have environmental and reliability benefits through higher efficiencies and reduced transmission and distribution requirements. Allowing customers to resell power at the retail price means that distribution costs are not recovered by the distribution company, requiring those costs to be recovered from sales to other customers. For this reason, net metering may face resistance and limits are often placed on the maximum amount of net metering allowed. The current analysis allows net metering of only residential buildings using PV[4].

Restructuring. This policy assumes that all states implement competitive wholesale markets for electric power by 2008 in the Advanced scenario and the Moderate scenario. This translates to pricing based on real-time marginal costs instead of regulated, average-cost-based rates. This is as opposed to the BAU case, in which marginal cost-based pricing is applied in the five regions of California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey, and Maryland), and the Mid-America Interconnected Network (consisting of Illinois and parts of Wisconsin and Missouri). Restructuring can cause other changes to the market, such as higher costs of capital, lower reserve margins, and flatter load shapes. It also allows the non-quantified benefits of choice of supplier and competition. This may create dynamic efficiencies that spur development of lower cost and higher value energy services to customers. A recent study by the Northeast Midwest Institute gives more details on the potential for efficiency improvements in a restructured market (Kaarsberg, 1999). Market forces are already at work in today’s environment changing the generation mix to more efficient and cleaner plants. For example, the top two types of plants built in 1998 were combined cycle gas turbines and wind plants.

---

[3] The Technical Optimism factor was reduced from 1.19 to 1.00. Technical optimism factors are a multiplier of the capital cost of the first few plants that gradually decline to unity by the fifth plant.

[4] In the industrial chapter, it is assumed that a portion of the electricity generated by combined heat and power systems is sold back to the grid at 60% of retail rates in the Moderate scenario and 80% in the Advanced scenario.

Stricter particulate matter (PM) emission standards. This policy assumes that PM standards are tightened in response to increasing concerns of their impact on health and the environment. The CEF-NEMS does not include PM emissions, however, one of the major precursors to the formation of small (< 10 microns) particulates is SO_2, which can be constrained in CEF-NEMS. Following the example of the EPA's analysis of mercury and particulate emissions (EPA, 1999), we restricted SO2 emissions to 50% below the current requirements. However, we delayed the ramping down to between 2010 and 2020, in part to shift policy impacts to the latter part of the study period.

Carbon trading system. In the Advanced scenario a cap is assumed on carbon emissions from all sectors of the economy. The cap is announced in 2002, implemented in 2005, and continued indefinitely. See chapter 1 for more details.

7.2.2 Additional Policy Pathways

There are additional electric-sector policies and opportunities (see Table 7.3) not included in our scenarios that we either modeled in our sensitivity analyses (see section 7.5.3) or which are discussed only qualitatively in this section. These include green power markets, distributed power markets, other market diffusion policies for renewable energy, various nuclear issues, emissions regulation mechanisms, hydroelectric power expansion, transmission and distribution (T&D) technology improvements, fuel switching from coal to gas, and efficient coal technology incentives.

Table 7.3 Additional Electricity Policy Pathways

Policy/Opportunity Areas	Potential Policies
Market Issues	Green Power market formation and standards Distributed power market facilitation
Renewable Market Diffusion	Supply Push policies (see Table 7.5 for details) Demand Pull policies Regulatory policies International Market policies Renewable Portfolio Standard
Hydroelectric Power Expansion	Increased R&D Extend renewable incentives to hydro
Nuclear Issues	Additional relicensing streamlining Spent Fuel Disposal resolution Ownership flexibility Decommissioning fund tax treatment
Emissions Regulation	Output-based allowance distribution Stricter emissions limits
Transmission & Distribution Technology Improvements	Increased funding of high temperature superconducting technologies
Clean Coal and Coal–to–Gas Technology Development	Recovery of sunk costs in a switch from coal to gas Production tax credits for efficient coal Investment tax credit for efficient coal Pool for risk-sharing of technology development

Market Issues. Green power markets represent a growing opportunity for renewables. Evidence to date shows that green products have had some success in markets newly opened to competition (Wiser, 1999). Niche markets clearly exist for green power. Residential demand has been most prominent, though nonresidential demand has been more significant than many expected. Nonetheless, it will clearly take time for the green market to mature, and there remain legitimate concerns about the ability of customer-driven markets to support significant amounts of renewable energy. Unfortunately, there is currently insufficient data with which to predict the long-term prospects for green power sales with any accuracy (Wiser, 1999). This analysis does not presume to explicitly forecast the impetus that green marketing alone can provide, but rather we assume that green marketing together with other programs will spur the development of a renewable energy infrastructure and a consumer awareness and comfort with the technology. A Renewable Portfolio Standard in effect overrides a green power market by mandating a level of renewable resources. Only if green power marketing would provide a higher penetration than the RPS alone would our analysis under-represent the potential of this market.

Distributed power markets also represent an opportunity for dispersed generation. The primary candidate technologies include reciprocating engines, gas-fired turbines, fuel cells, and photovoltaics. To a limited extent we have captured some of this potential in our modeling of photovoltaics in the buildings sector. However, there also exists a large market for non-customer owned generation within the distribution system. Such generation could have a wide range of impacts on carbon emissions and local air pollution. On the positive side, distributed generation technologies may be non-emitters, like photovoltaics, or lower emitters, like fuel cells. Emissions would also be reduced since less generation would be required due to the absence of losses in the transmission of power. On the other hand, more emissions might result from the use of smaller less-efficient combustion turbines, and criteria pollutant emissions would be moved closer to population centers. These opposing impacts, together with the difficulty of modeling this very site-specific opportunity, have kept us from assessing this opportunity or the facilitating policies that could spawn it. However, a range of possible impacts is provided in the integrating chapter 1.

Combined heat and power (cogeneration) has been included in the industrial sector (Section 5.5.4) instead of the electric sector. Yet, it represents a significant contributor to the overall electricity output of the country. Table 7.4 shows the amount of capacity and energy that could be available from this source as determined by the analysis described in Appendix E-5 that was conducted outside of the CEF-NEMS model. Due to difficulties in modeling CHP in CEF-NEMS, these sources are not included in the production numbers in this chapter. If it were possible to include these values in the CEF-NEMS model runs, then our projections of electric sector capacity expansion would be significantly reduced. By 2020, additional cogeneration could reduce non-cogeneration production by another 16% from what is already included in the CEF-NEMS runs.

Table 7.4 Additional Cogeneration Capacity and Electrical Generation (from Table 5.10)

	2010			2020		
	BAU	**Mod.**	**Adv.**	**BAU**	**Mod.**	**Adv.**
Capacity (GW)	4	14	29	9	40	76
Generation (TWh)	31	98	201	62	278	539
% of non-cogeneration production (from Table 7.9)	0.8%	2.7%	5.7%	1.4%	7.3%	15.7%

Renewable Market Diffusion. Another category of options not explicitly considered here focuses on the process by which renewable technologies enter the market place. Since renewable technologies are not widespread in the market, they face a number of barriers common to all emerging technologies. These barriers include lack of information about the technologies, uncertainty about technology performance, and incompatibility with existing infrastructure. These market barriers can be addressed by a wide variety of policies. These include direct policies such as those shown in Tables 7.2 and 7.3 above, as well as more indirect policies like information programs that affect the diffusion process strongly in its early stages.

The range of these diffusion-related policies is illustrated by the results (see Table 7.5) of a recent scenario-based workshop, which focused on policies to encourage the significant penetration of renewable technologies in the U.S. in the next several decades. Many of these policies interact with each other to accelerate the diffusion process. As shown by Table 7.2, in this study we have quantified only the major policies that directly impact the economics of renewable technologies. A related working paper (Kline and Laitner, 1999) examines the issues involved in assessing the impact of the more indirect policies related to market diffusion.

Table 7.5 Renewable Market Diffusion Policies from Scenario Workshop

Supply Push	Demand Pull
• Large scale public/private partnerships in RD&D • Expand Climate Wise and Energy Star programs into renewable energy technologies • Refine and disseminate renewable energy resource data • Standardized procedures for selling and interconnecting intermittent renewables to the electric grid • Demonstrations of hybrids in distributed applications • Other large-scale demonstrations through public/private partnerships	• Green power certification • Power source disclosure requirements • Public/private partnerships for biofuels (and other technologies) • Competition to develop new user-side infrastructure to support renewables • Government purchases of renewables • Popular marketing campaign (e.g. Popular Mechanics)
Regulatory Measures	**International Markets**
• System Benefit Charges and guidance to accelerate renewable energy penetration. • Develop, promote methodology for evaluating distributed generation benefits of renewables • Integrate renewables into emissions enforcement procedures • Outreach/education for state legislatures • Outreach to federal agencies • Push dissemination of atmospheric research results	• International demonstrations by public/private partnerships • Promote (first quantify) environmental benefits of renewable energy technologies to developing countries

Nuclear Issues. A third set of policies that we have not analyzed quantitatively relates to nuclear power. Such policies include a definitive resolution to the spent fuel storage/disposal issue, licensing reform in the area of ownership requirements, and federal mechanisms to ensure full funding of nuclear plant decommissioning without penalties due to corporate restructurings or ownership transfers. These polices can be reflected in the analysis through further lowering of relicensing costs or ongoing O&M costs, but additional analysis is needed to quantify them, if such costs are even included in the BAU costs provided by EIA. Further discussion can be found in Appendix E-3.

Spent fuel storage/disposal policy. Many nuclear plants are faced with a near-term problem of lack of storage space for their spent nuclear fuel. Some state regulations stipulate that a nuclear power plant cannot operate if it does not have sufficient on-site storage capacity. Uncertainty about how and when the federal government will meet its obligation to provide storage and disposal facilities for used nuclear fuel represents one of the most significant business risk factors for nuclear power plants. The Department of Energy has been conducting an exhaustive scientific assessment of a permanent disposal site at Yucca Mountain, NV, but it is more than 12 years behind schedule, and no site has been selected for an interim storage facility. While resolution of this issue is needed for the permanent storage of wastes, lack of a disposal facility will not cause premature shutdowns in and of itself. Alternative technical solutions to avoid shutdowns are available but require acceptance by the stakeholders involved.

Licensing reform regarding foreign ownership requirements. Sections 103d and 104d of the Atomic Energy Act prohibits foreign ownership of commercial nuclear facilities. In the evolving power market such restrictions impact competition. They could be removed, except where they pertain to national security concerns. As a barrier to entry, these restrictions limit the number of potential investors in U.S. nuclear assets, resulting in a downward bias in the value of such assets and a likelihood of premature shutdown. Existing owners that are not willing to continue operating a plant but unable to sell it to those most willing to, may choose to retire the plant instead.

Federal mechanisms to ensure full funding of nuclear plant decommissioning. Because decommissioning of nuclear power plants is a public health and safety issue, a federal mandate and mechanism could be established to ensure recovery of unfunded decommissioning obligations¾via a non-bypassable charge¾when a nuclear asset is sold. In addition, the Internal Revenue Code could be amended to ensure that, with the sale of a nuclear asset, the transfer of decommissioning funds are not taxed as capital gains. Without these mechanisms, nuclear plant economics are negatively affected.

Emissions Regulation Mechanisms. Other possible policies that could support non-emitting generators hinge on the economic recognition of their clean air compliance value. One such policy, an output-based emission standard, would allocate emissions allowances to all producers on the basis of their electricity production output, rather than the fuel input used. This change in the distribution of allowances would force emitters to purchase from non-emitters the required allowances for their production. Non-emitters would benefit both from the sale of their allowances and the higher marginal prices for electricity (since emitters would include the cost of allowances in their variable costs.) The impact would depend on the relative demand and supply of allowances, and consequent market price. The difficulty in modeling the inter-sectoral and cross-sectoral trading needed for such an approach limits our ability to analyze it.

Hydroelectric Power Expansion. Hydropower is often characterized as either a fully developed energy resource that needs no new attention in national energy strategies or as an energy source that should be discouraged because of its adverse environmental effects. Neither of these points of view are completely accurate. While hydropower currently supplies about 98% of the electric generation from renewables, it still can provide significant, additional benefits to control of greenhouse gas (GHG) emissions. There are approximately 60 GW of undeveloped hydropower available in the U.S., distributed across three types of projects: 1) equipment upgrades at existing hydropower facilities, 2) new development of generation facilities at existing dams, and 3) new development at new dams or diversions. With advanced technologies that are becoming available (e.g., fish-friendly turbines), the first two of these types of projects would have net benefits in terms of improved environmental performance and GHG reductions.

The third category of undeveloped resource is more problematic, because of the new construction involved. However, the estimate of those hydropower resources employed an environmental screen by state resource managers to exclude sensitive and protected sites (Rinehart et al., 1997) (i.e., environmentally unsuitable sites are not included in this estimate).

The magnitude of undeveloped hydropower is relatively large, especially with respect to near-term potential. Approximately half of this resource could be developed by 2010 if hydropower is included among the renewables targeted for encouragement. New initiatives for conducting life-cycle analysis and defining low-impact hydropower are being developed by scientific organizations, environmental groups, and energy marketers, for marketing hydropower as “green” energy in the retail power market.

To achieve new, environmentally preferable hydropower, continued federal funding for RD&D projects is needed. DOE’s Advanced Hydropower Turbine Systems Program has been successful in the development of innovative technologies that will enhance the environmental performance of hydropower projects and in attracting both interagency cooperation and industry cost-sharing. On the policy side, environmentally preferable hydropower needs to have full access to the market incentives for other renewables, if hydropower’s GHG contributions are to be realized.

Estimating supply functions for hydropower is inherently difficult because of the highly site-specific nature of development costs (e.g., FERC, 1988). Resource studies to date (e.g., Rinehart et al., 1997; DOE Hydropower Assessment Program 1999) have not included the type of information needed to provide the level of economic analysis possible with other renewables. Additional federal and/or private resources should be invested in an expanded hydropower resource assessment, so that its true potential can be factored into national planning. Any new resource assessment should be done in cooperation with both the industry and environmental groups. Indications are that the hydropower industry is ready and willing to participate.

One example of the unresolved controversies that plague the hydropower industry is the fate of hydroelectric generation during the relicensing process at non-federal projects. Every 30 to 50 years, non-federal hydropower projects must obtain a new operating license from FERC. This relicensing process is an opportunity to add new environmental operating constraints, such as minimum flow requirements or fish ladders or screens. It is also a time when generating equipment can be upgraded or decommissioning can be considered. A basic question is how is contemporary relicensing affecting the total generating capacity of hydropower in the U.S.? Answers range from an average of 8% loss in capacity (Hunt and Hunt, 1997) to less than 1% change. Anecdotal evidence from individual proceedings indicates that many opportunities to upgrade equipment at relicensing are being foregone, probably due to local economic decisions and regulatory uncertainty. The latter has drawn attention from Congress. Pending legislation designed to resolve some of this uncertainty may be enacted, but the cost of relicensing will remain high. Environmental mitigation costs are also quite high in relicensing, but there are no definitive studies that can quantify these costs. Hydropower is a resource that should be tapped to the extent feasible, both environmentally and economically, in order to address GHG controls, especially on the near term.

Other new policy options that could be pursued for hydropower include the following:

- regulatory reform to ensure that environmental mitigation requirements in relicensing are justified,
- incentives for equipment upgrades of existing facilities for both power production and enhancements to environmental performance, and
- development of objective criteria for evaluating the environmental performance of hydropower projects in relation to other regional energy projects.

T&D Technology Development. Electric power T&D systems transfer generated power from central power stations and distributed generators to customers elsewhere on the power grid. Energy losses in the U.S. T&D system were 7.2% of total generation in 1995, representing 2.5 quads of energy and 36.5 MtC of carbon emissions (DOE National Laboratory Directors, 1997). High voltage direct current transmission, high temperature superconducting (HTS) cables and transformers, more efficient line transformers, and real-time control using automated controls could all improve the efficiency of the T&D system. Projections indicate that the most significant impacts of these technologies (20-25 MtC savings per year) will occur beyond 2020, as existing equipment is replaced and new technologies are available for capacity expansion. However, some savings, 3-6 MtC/yr, could occur if currently available technologies become more economical and accepted. Domestic research is aimed at improving HTS cables and transformers through longer cable lengths at lower cost and improved cryogenic refrigeration. Several demonstrations are already underway, including a replacement of distribution lines in a crowded urban location in Detroit, MI (EPRI, 1999).

Coal Technology Development. Carbon emissions at existing coal-fired power plants could be reduced through efficiency improvements (via clean coal technologies) or reliance on carbon capture/ sequestration technology (when it becomes commercially economic). Another option is to convert such plants from coal to natural gas. Some fuel switching is already occurring, where coal-fired power plants are being purchased and converted to natural gas combined cycle (NGCC) facilities (e.g., Detroit Edison converted its 200 MWe Connors Creek plant, which became operational in June 1999). Such conversions reduce not only carbon emissions but also criteria air pollutants, and permit capacity expansion in airsheds that would otherwise prohibit new generating capacity. Electric generating companies compare the projected cost of continued operation (of the coal-fired power plant) with additional compliance equipment against the cost of switching to gas to meet future electric load and environmental requirements.

In general, the economics of switching from a plant designed to use an inexpensive fuel (coal) for a more expensive one (gas), while requiring significant capital expenditures, are not favorable. Also, space restrictions, access to natural gas pipelines, and local permits can preclude such conversions. In addition to these site factors, the sunk cost in the coal-fired power plant (e.g., boiler, coal handling equipment, emissions control equipment) could make such a conversion uneconomic. Such sunk costs may not be recoverable, either in a regulated rate-of-return environment or competitive power market (via a competitive transition or stranded cost charge). In a regulated market the equipment may be declared no longer "used and useful" so it would be withdrawn from the rate base. In a competitive power market, the investment represents a sunk cost that does not enter into future "going forward" costs when compared against the value of switching to gas.

A potential policy pathway is to reimburse generators who switch to gas for the coal-related sunk costs, either through a tax credit or an electricity surcharge, such as a stranded cost or competitive transition charge. A potential problem with such a policy is the possibility of "free riders," – generators who take advantage of the reimbursement but would have switched anyway based solely on economic criteria. Such a policy option would require further examination before it could be recommended (or implemented).

Carbon emissions reduction could also be accomplished through deployment of more efficient coal technologies—that either replace retirement-age pulverized coal-fired boilers, or serve new load growth instead of less efficient technologies. While coal—by its nature—has a high carbon content, clean coal technologies (CCT) have a lower carbon emissions rate than pulverized coal (PC) boilers used today. For example, a 34% efficient pulverized coal boiler has a carbon emission rate of 260 g/kWh, while a 42% efficient integrated coal gasification combined cycle (IGCC) facility has a rate 20% lower, or 210 g/kWh.

So for every Gigawatt-hour (GWh) of electricity generated by IGCC (relative to a PC boiler) 50 metric tons of carbon would be avoided (not emitted). By 2020, advanced coal-fired plants may achieve 60% efficiency through R&D, reducing their carbon emission rate to 150 g/kWh, and saving 110 tons per GWh relative to an average current-day coal plant.

However, most CCTs are not currently considered "commercial" for power generation applications, so their capital and operating costs have a technology risk premium. (In the AEO99 the risk premium —the difference in capital cost between the first-of-a-kind and fifth-of-a-kind plant— is equivalent to $515/kW.) This technology risk premium makes CCTs more expensive than the current technology of choice, natural gas combined cycle (NGCC).

A number of studies have examined alternative incentive mechanisms to accelerate the deployment of CCTs (see Spencer, 1996 for a review). Three studies derived the level of CCT incentives necessary to be cost-competitive with NGCC (South, et al, 1995; Spencer, 1996; and CURC, 1998). The Coal Utilization Research Council (CURC) determined that the following incentives are necessary for the first 1,500 MW of each type of CCT:

- Investment tax credit: tax credit equal to 20% of owner's equity investment, applicable to first 4 years of construction.
- Production tax credit: tax credit based on design average net heat rate, with an incentive (0.70 - 1.30 cents/kWh depending on heat rate) for years 1-5, and a lower incentive (0.45-1.10 cents/kWh depending on heat rate) for years 6-10. The production tax credit would apply to the years 1-10 of operation.
- Financial Risk Pool: the Federal government would establish a financial risk pool applicable in years 1 thru 3 of operations to offset costs arising from technology non-performance (relative to design) during start-up and initial operation. The total amount of recoverable costs is limited to 5% of total project installed cost.

While these financial incentives are needed to make CCTs competitive with NGCC (using a cash flow analysis), the level of incentives exceed the carbon value targets inherent in the Moderate and Advanced scenarios of this study. For example, a production tax credit of 0.25¢/kWh over 10 years is equivalent to $24/tC, and a 0.50¢/kWh production tax credit is equal to $48/tC. Thus, implementation of the full set of incentives proposed by CURC would translate into a carbon value greater than $200/tC. This value could be reduced depending on the amount of additional capacity that these incentives would spur after they have expired.

7.2.3 Barriers Analysis

Barriers to the potential improvements in electricity technology have been broadly classified in Table 7.6 and defined just below the table. Also listed are some of the policies to be analyzed using the CEF-NEMS model. The mark in the cells of the table mark where a potential policy responds to the barrier identified.

Table 7.6 Barriers and Policies

	Production Tax Credit	Wind Facilitation	Enhanced R&D	Net metering	Nation-wide Restructuring	Stricter Air Emission	Carbon Trading
1) Generation costs do not include all costs of emissions						X	X
2) Regulated market structure does not reward innovation well	X		X		X		
3) Regulated market structure limits competition	X			X	X		
4) Public benefits of R&D are not captured by investors			X				
5) System planning and operations do not handle non-dispatchability well	X	X		X			

1) **Emissions costs:** The absence of full costs of emission damages from fossil generators distorts the electricity generation markets towards fossil fuels. Existing control costs are embedded in the cost of electricity. While current EPA regulations enforcing the Clean Air Act and other Federal legislation impose control costs on the marginal emitter of criteria pollutants like SO2 and NOx, these control costs are not the same as the damage costs. And inasmuch as the regulations allow some older fossil generators to continue to emit, not all existing fossil generators incur operating cost penalties. Furthermore, there are several emissions produced by fossil fuel combustion that are not capped today. These include carbon, mercury, and smaller particulates (2.5 micron). No costs are currently included to account for damages from these pollutants.

2) **Innovation rewards:** The traditional, regulated electricity market allows utilities a reasonable return on their investment, as defined by regulators. With a relatively low-risk return based on capital investment, there is little direct monetary incentive to lower costs or improve efficiencies. Guaranteed returns can even provide an incentive to hang on to non-cost-effective plants until they are fully amortized, and to replace cost-effective plants that are fully amortized. The industry has relied on regulatory pressure to keep costs down, and to use regulatory lag to reward innovation. There is a reward for innovations that lead to increased sales of electricity (or reductions through demand side management). These have led to industry-wide improvements over time, but the rewards were shared over all industry rather than garnered by individual innovators.

3) **Competition:** In addition, the regulated electricity market established exclusive franchises that limited the amount of competition. The “regulatory compact” of limited competition for regulated rates worked well to keep prices reasonable and extend the benefits of electrification to all, especially

when economies of scale were large and thus large monopolists could lower prices better than small firms. However, this system lessened the opportunity for innovation through competition.

4) **R&D:** While the traditional regulated utility structure did not strongly drive innovation, it did provide capital for research and development. In today's more competitive electric sector, R&D funding has decreased dramatically. The barrier to increased R&D is the public goods aspect of R&D. Companies will not fund the optimal societal level of basic R&D of new technologies, since many of the benefits of such research will flow to their competitors and to other parts of the economy. This is true of many industries, and is one of the main rationales for government-funded long-term, pre-competitive research in industries that have a vital role in the U.S. economy.

5) **Non-dispatchability:** The electric system requires extensive control over the level of production in order to match demands precisely. Intermittent sources and generation sources outside of the direct control of the system operators are not easily incorporated into system planning and operations. Consequently, there has been a devaluing of their contribution to the system, which has created a barrier to their widespread acceptance.

7.3 METHODOLOGY

7.3.1 Modifications to CEF-NEMS for the BAU Scenario

Besides the policy scenarios to be analyzed, a new Business As Usual (BAU) scenario was established for this CEF study. The BAU scenario was developed through limited modifications to the AEO99 Reference scenario. These modifications to the Electricity Market Module (EMM) of CEF-NEMS were made to represent technologies and markets more realistically. A brief general description of the EMM can be found in Chapter 3. The changes for the electric sector to the BAU scenario are documented below:

Wind. In CEF-NEMS some of the EMM constraints imposed by NEMS on wind market penetration have been altered. These changes were made to more accurately reflect what the authors feel to be the current market for wind. These changes did not deal with the actual operation of a wind plant (e.g., operating cost, capacity factor) but with market-related growth limitations imposed in NEMS. While these changes were made for all three scenarios, i.e., including the BAU scenario, they had no impact on the BAU scenario results because very little wind penetrates in that scenario and therefore the constraints in the EMM linear program are not binding. Thus these modifications could alternatively be considered to reflect a set of policy changes in the Moderate and Advanced scenario that facilitates wind deployment (see Table 7.2) The constraints modified are listed below in Table 7.7 and described in detail in Appendix C-4.

Table 7.7 Modifications to NEMS Constraints on Wind

NEMS EMM	CEF-NEMS EMM
Maximum construction of 1GW in a region in a single year	Deleted
Short-term supply elasticity: 70% increase in capital costs for national growth above 14% per year	Reduced to 5% penalty for annual national growth between 20 and 30% and 15% penalty above 30% growth.
Intermittency: Max wind generation < 10% regional generation	Replaced by capital cost multiplier below
Capital cost increased by a factor of 3 for 90% of all wind resource due to site access, intermittency, & market factors	Capital cost increased by as much as 60% as regional market penetration rises from 10% to 20%

Biomass cofiring. All the scenarios shown here, including the BAU scenario, allow biomass cofiring of coal plants (the AEO99 reference case did not).

Nuclear. For the AEO99, "In the reference case, it is first assumed that a retrofit costing $150 per kilowatt will be required after 30 years of operation to operate the plant for another 10 years." (EIA, 1998b) If its "going forward" cost, including the 10-year $150/kWe incremental capital charge, is less than the minimum cost of new baseload capacity, then the nuclear unit is assumed to continue in operation through its 40-year license period. If not, then the plant is assumed to be retired at the 30-year date. The $150/kWe charge is intended to account for large equipment replacement expenditures, such as, for example, a steam generator in the case of a pressurized water reactor (PWR). If a PWR has had a steam generator replaced in the several years prior to year 30 then the $150 charge is not applied. In addition, in the AEO99 reference case, "A more extensive capital investment ($250 per kilowatt) is assumed to be required to operate a nuclear unit for 20 years past its current license expiration date." (EIA, 1998b) It is assumed that the operating license will be extended from 40 to 60 years if the sum of the going-forward cost and a capitalization of the life extension cost over 20 years is less than the minimum cost of constructing replacement baseload capacity. Otherwise the plant is retired.

The nuclear plant refurbishment and relicensing costs have been modified in the CEF-NEMS to reflect more closely the empirical estimate of $180/kW for these activities. (See Appendix E-3 for the calculation.) This entailed retaining the $150/kW charge at year 30, but reducing the year 40 charge to $50/kW to approximate the total $180/kW charge for life extension and license renewal. Recent comments from EIA state that the $150/kW and $250/kW costs are not capital expenditures but are to represent age-induced increases in operating costs. The evidence of age-induced increases in nuclear facilities is mixed. By lowering the 40 year value, we do not include this extra expense.

Geothermal. Construction of geothermal capacity is modeled on a site-by-site basis within NEMS. If any capacity is added to a site, there is a waiting period constraint before any additional capacity can be added at that site. In the AEO99, this waiting period was set at six years, greatly slowing the speed that any geothermal could be added. In addition, the NEMS model uses a logit function for allocating capacity additions between technologies. This serves to avoid the "knife-edge" problem of one technology receiving all capacity additions even if it is just slightly below the cost of others. However, the function can cause a very small amount of capacity to be added at all geothermal sites. The waiting period then forecloses any additions for another six years, thereby greatly reducing the amount of geothermal capacity that can be built over the study period. For the scenarios in this study, we changed the length of the waiting period to zero so that capacity can be added the next year if it is economical to do so.

7.3.2 Policy Modeling within CEF-NEMS

As discussed in Chapter 3, most of the results developed for the electric sector were modeled almost entirely in the EMM of CEF-NEMS. A brief general description of the EMM can be found in Chapter 3. Table 7.8 shows the analysis approach used for policies specific to the electric sector. The detailed parameter settings that varied between the Moderate and Advanced scenarios can be found in Appendix C-4 along with details on their derivation. Policies were not examined individually, but rather as a set within each of the three scenarios – BAU, Moderate, Advanced.

Table 7.8 Modeling of Policies

Policy	Modeling Approach
Production Tax Credit	For each renewable technology, the present value of the 10 year tax credit is levelized over plant lifetime and inserted as the EMM parameter for tax credits
Renewable Portfolio Standard	The PTC for non-hydro renewables (above) was extended from 2004 to 2008. The biomass cofiring tax credit was extended to 2014.
Expanded R&D	Two steps are involved: 1) To estimate how much expanded R&D will improve a technology's cost and performance, existing, published estimates of future technology improvements were used. 2) These estimates were inserted into the technology parameters of the EMM that characterize each technology.
Net Metering	CEF-NEMS competes fuel cells and PV with retail electricity prices in the residential sector. Limits can be placed on the amount of sales displaced by such on-site generation
Restructuring	Marginal cost pricing is used in EMM for all regions Discount rates are increased in EMM Amortization periods are shortened in EMM Reserve margins are decreased in EMM
Tighter SO_2 Limits	The allowed ceiling for SO_2 was reduced from 895 million tons in 2010 to 448 million tons in 2020 in steps of 45 million tons per year
Carbon Trading System	Within CEF-NEMS, fuel costs are raised based on the expected price of carbon allowances. These costs are used in all sectors' analyses, not just the electric sector.

7.4 SCENARIO RESULTS

7.4.1 Overview

The scenarios as described have been run through the CEF-NEMS model, in conjunction with the scenarios defined in the end-use sectors. The key results of the three scenarios are shown in the following tables and figures.

Table 7.9 Generation by Scenario by Electric Generators (TWh) (no cogeneration)

			2010			2020		
Fuel	**1990**	**1997**	**BAU**	**Mod.**	**Adv.**	**BAU**	**Mod.**	**Adv.**
Total	2850	3190	3920	3680 (-6%)	3520 (-14%)	4420	3800 (-12%)	3440 (-22%)

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv. = Advanced scenario. Numbers in parentheses represent the percentage change compared to the BAU scenario.

Table 7.10 Primary Energy Use by Scenario and Fuel in the Electric Sector (quadrillion Btu) (no cogeneration)

			2010			2020		
Fuel	**1990**	**1997**	**BAU**	**Mod.**	**Adv.**	**BAU**	**Mod.**	**Adv.**
Coal	16.1	18.6	21.2	20.2 (-4%)	14.4 (-32%)	22.4	20.7 (-8%)	10.9 (-51%)
Natural Gas	2.88	3.4	6.6	5.0 (-24%)	6.1 (-9%)	8.8	5.9 (-34%)	7.2 (-18%)
Distillate	0.02	0.1	0.0	0.0 (-0%)	0.0 (-33%)	0.0	0.0 (-33%)	0.0 (-33%)
Residual	1.23	0.8	0.2	0.1 (-26%)	0.1 (-37%)	0.2	0.1 (-20%)	0.1 (-47%)
Nuclear	6.20	6.7	6.2	6.2 (-0%)	6.7 (9%)	5.6	4.9 (-11%)	6.4 (15%)
Hydro[b]	3.6[a]	3.6	3.3	3.3 (-0%)	3.3 (0%)	3.3	3.3 (-0%)	3.3 (0%)
Non-hydro renew energy[b]	a	0.8	1.5	2.3 (55%)	3.8 (161%)	2.3	3.2 (41%)	4.6 (98%)
Electricity Imports	0	0.3	0.3	0.3 (-0%)	0.3 (6%)	0.3	0.3 (-0%)	0.3 (0%)
Total	30.07	34.3	39.3	37.5 (-5%)	34.8 (-11%)	42.9	38.6 (-10%)	32.8 (-24%)

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv. = Advanced scenario. Numbers in parentheses represent the percentage change compared to the BAU scenario.

[a]1990 Hydro includes non-hydro renewable energy.

[b] Hydro, solar, and wind primary energy use assume a fossil-fuel heat rate equivalent of 10,280 Btu/kWh. Nuclear plants assume a value of 10,623 Btu/kWh.

Table 7.11 Generation by Scenario and Fuel in the Electric Sector (TWh) (no cogeneration)

			2010			2020		
Fuel	**1990**	**1997**	**BAU**	**Mod.**	**Adv.**	**BAU**	**Mod.**	**Adv.**
Coal		1800	2020	1940 (-4%)	1400 (-31%)	2170	2000 (-8%)	1060 (-51%)
Petroleum		80	22	17 (-23%)	14 (-36%)	18	15 (-17%)	11 (-39%)
Natural Gas		300	890	680 (-24%)	880 (-1%)	1270	830 (-35%)	1140 (-10%)
Nuclear Power		630	580	580 (0%)	630 (9%)	520	460 (-11%)	600 (15%)
Renewables		390	410	460 (13%)	590 (45%)	440	500 (13%)	630 (42%)
Hydro		350	320	320 (0%)	320 (-0%)	320	320 (0%)	320 (0%)
Wind		3	8	37 (386%)	140 (1760%)	9	51 (495%)	160 (1770%)
Biomass		4	26	37 (43%)	47 (83%)	31	26 (-17%)	48 (55%)
- Dedicated		4	11	15 (35%)	22 (100%)	19	16 (-12%)	32 (69%)
- Cofired		0	15	22 (49%)	25 (70%)	13	10 (-24%)	17 (33%)
Geothermal		16	24	37 (55%)	50 (109%)	47	67 (41%)	67 (41%)
Other		15	28	28 (0%)	28 (0%)	31	31 (0%)	31 (0%)
Other		-3	-1	-1 (0%)	-1 (0%)	-1	-1 (0%)	-1 (0%)
Total		3190	3920	3680 (-6%)	3520 (-10%)	4420	3800 (-14%)	3440 (-22%)
Net Imports		32	30	30 (0%)	32 (7%)	27	28 (4%)	30 (0%)

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv.= Advanced scenario. Numbers in parentheses represent the percentage change compared to the BAU scenario.

Table 7.12 Carbon Emissions by Scenario and Fuel in the Electric Sector (MtC) (no cogeneration)

			2010			2020		
Fuel	**1990**	**1997**	**BAU**	**Mod.**	**Adv.**	**BAU**	**Mod.**	**Adv.**
Petroleum	26.8	17.6	4.6	3.4 (-26%)	2.9 (-37%)	3.7	3.0 (-19%)	2.1 (-43%)
Natural Gas	41.2	44	95	72 (-24%)	87 (-9%)	127	85 (-33%)	98 (-23%)
Coal	409	471	545	521 (-4%)	370 (-32%)	578	531 (-8%)	282 (-51%)
Total	477	532	645	597 (-7%)	460 (-29%)	709	622 (-12%)	382 (-46%)

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv.= Advanced scenario. Numbers in parentheses represent the percentage change compared to the BAU scenario.

Table 7.13 Capacity of Selected Technologies in the Electric Sector (GW) (no cogeneration)

			2010			2020		
	1990	1997	BAU	Mod.	Adv.	BAU	Mod.	Adv.
Coal Steam	300	305	307	303	262	320	305	225
Other Fossil Steam	144	139	81	76	56	77	56	33
Combined Cycle	8	16	126	107	122	199	134	149
Combustion Turbine/Diesel	46	78	149	142	135	184	145	133
Nuclear Power	100	99	78	78	87	72	64	83
Renewable	82	88	93	103	136	98	111	145
Hydro	75	78	79	79	79	79	79	79
Wind	2	2	3	12	43	4	15	47
Biomass	2	2	2	3	4	3	3	5
Geothermal	3	3	4	5	7	7	9	9
Other	1	4	5	5	5	5	5	5
Other	18	20	22	22	22	22	22	22
Total	698	744	855	831	819	971	837	789

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv.= Advanced scenario.

Table 7.14 Other Air Emissions in the Electric Sector (no cogeneration)

			2010			2020		
	1990	1997	BAU	Mod.	Adv.	BAU	Mod.	Adv.
SO_2 Emissions ($MtSO_2$)	15.6	11.6	8.4	8.3	8.5	8.2	8.2	4.3
SO_2Allowance Price ($/ton)	—	77	224	211	98	114	96	161
NO_x Emission ($MtNO_x$)	7.5	5.3	3.7	3.5	2.7	3.8	3.5	2.2

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv.= Advanced scenario.

Table 7.15 Electric Sector Fuel and End-Use Electric Prices ($/MBtu)

		2010				2020			
	1997	BAU	Mod.	Adv.	Adv. w/o C	BAU	Mod.	Adv.	Adv. w/o C
Petroleum Products	2.88	3.79	3.78	5.01	3.94	4.19	4.16	5.56	4.49
Natural Gas	2.70	3.01	2.67	3.40	2.68	3.04	2.53	3.09	2.37
Coal	1.27	1.06	1.05	2.34	1.05	0.93	0.92	2.20	0.91
Electricity (¢/kWh)	6.9	6.1	5.6	6.6	5.9	5.5	5.3	6.1	5.5

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv.= Advanced scenario. Advanced scenario prices include carbon values.

Fig. 7.1 Total Generation Including Cogeneration (TWh) (no cogeneration)

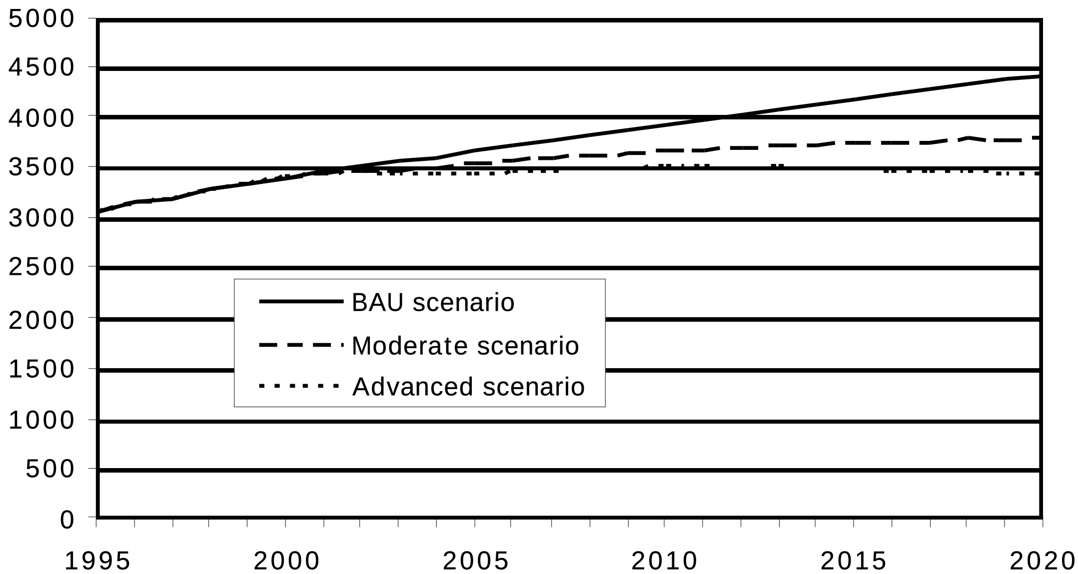


Fig. 7.2 BAU Scenario Total Generation by Fuel (TWh) (no cogeneration)

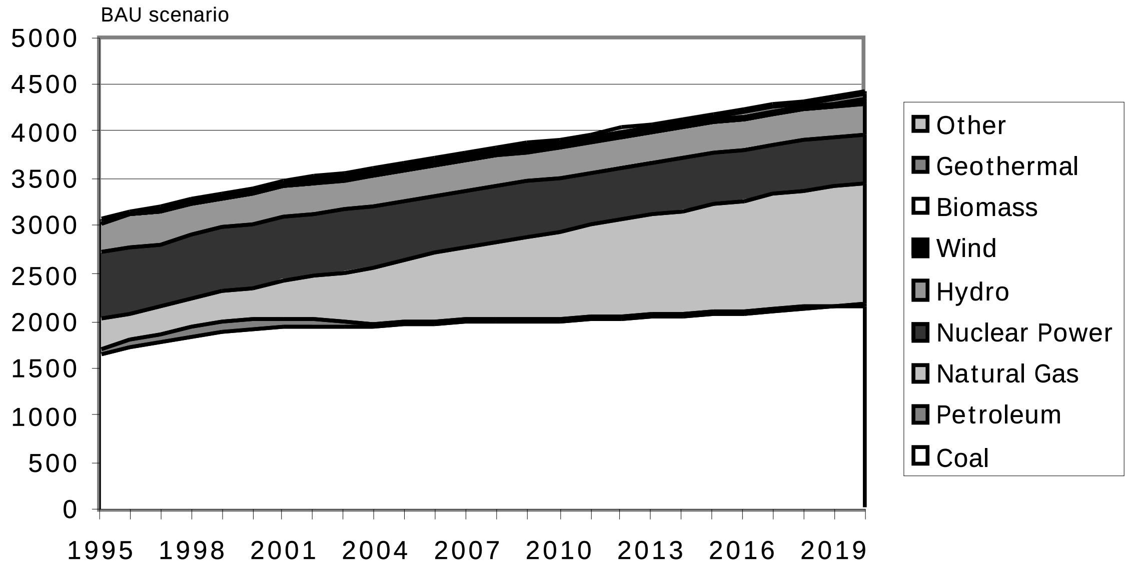


Fig. 7.3 Moderate Scenario Total Generation by Fuel (TWh) (no cogeneration)

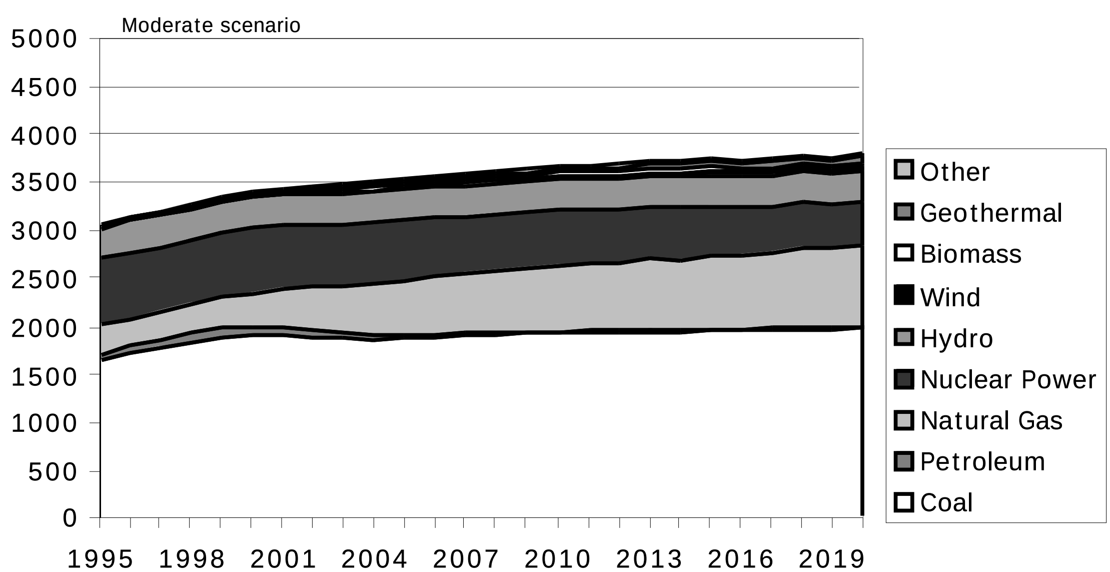


Fig. 7.4 Advanced Scenario Total Generation by Fuel (TWh) (no cogeneration)

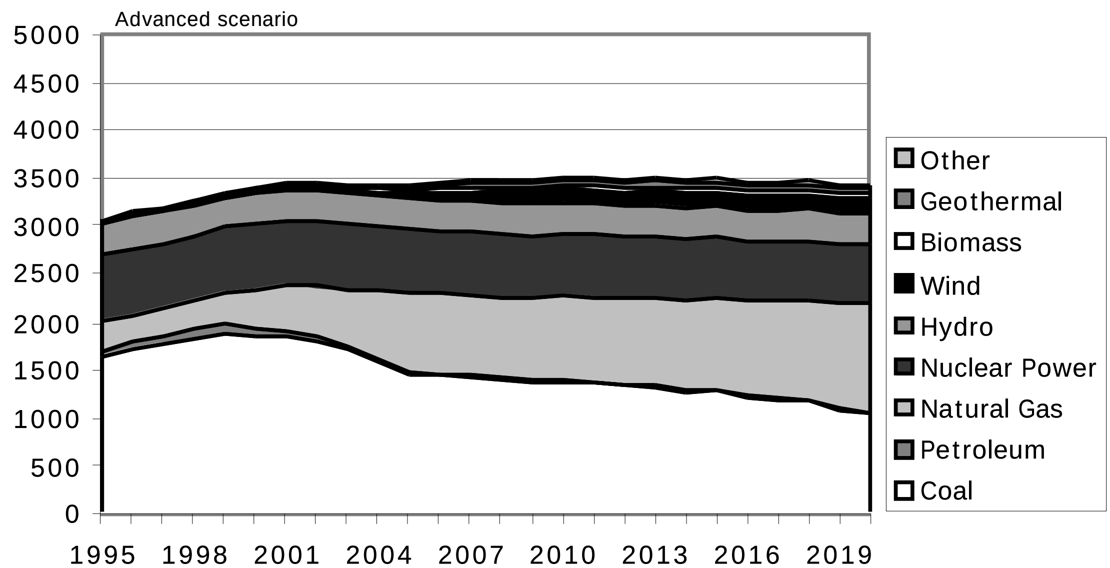


Fig. 7.5 Gas-Fired Generation Weighted Average Heat Rate (Btu/kWh)

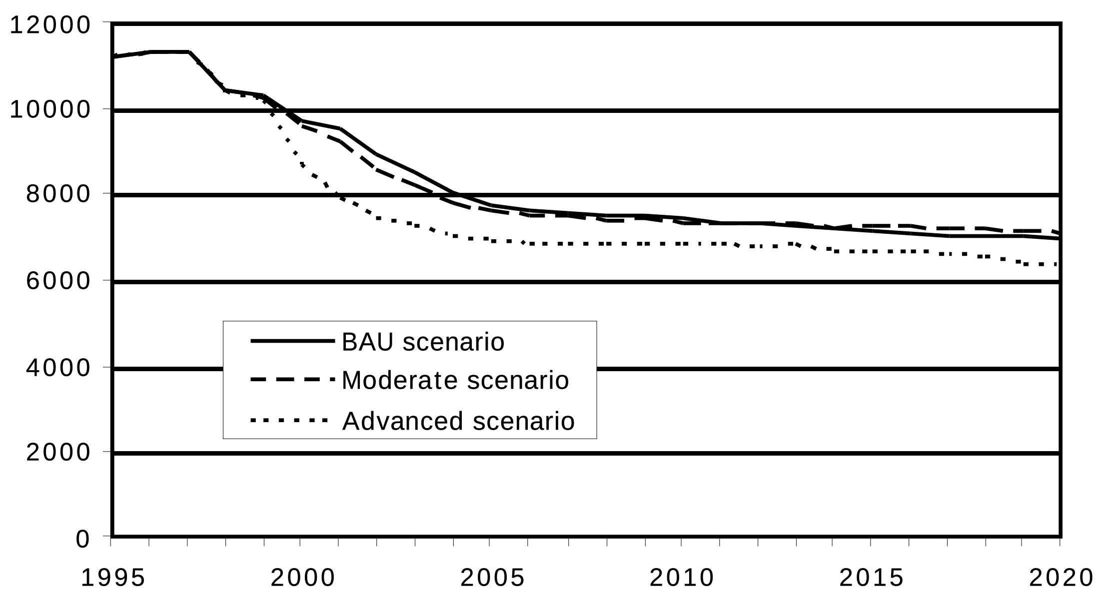


Fig. 7.6 Biomass Cofired Generation (% of Coal Generation)

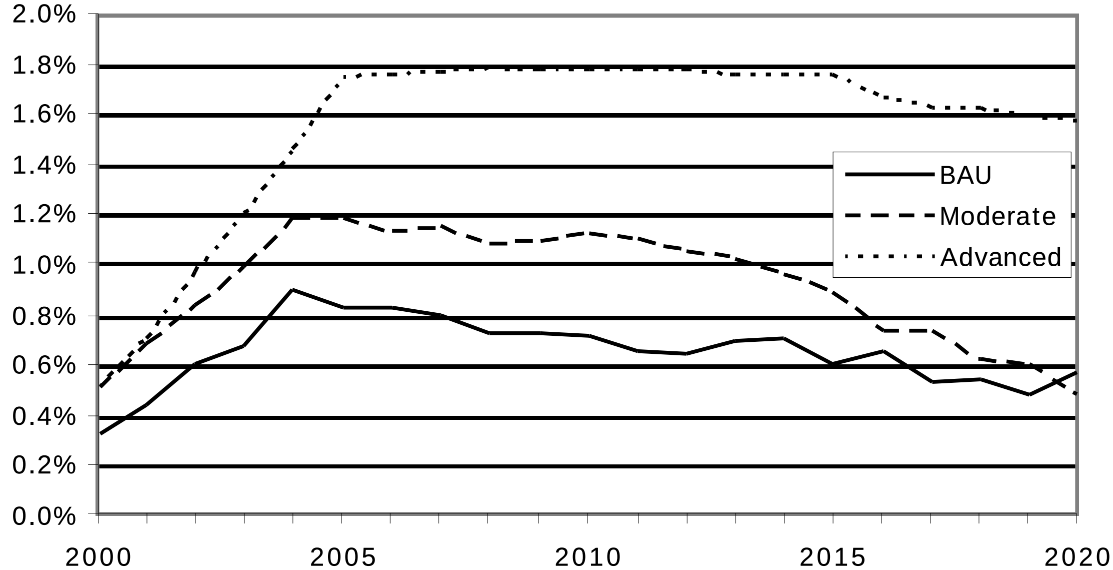


Fig. 7.7 Wind Capacity (GW)

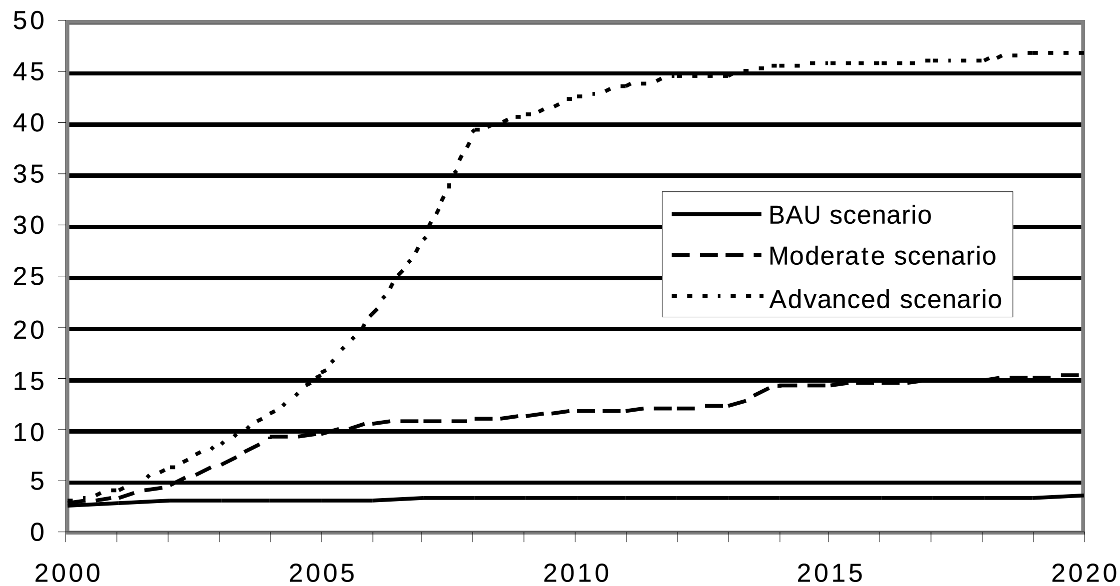


Fig. 7.8 Dedicated Biomass Capacity (GW)

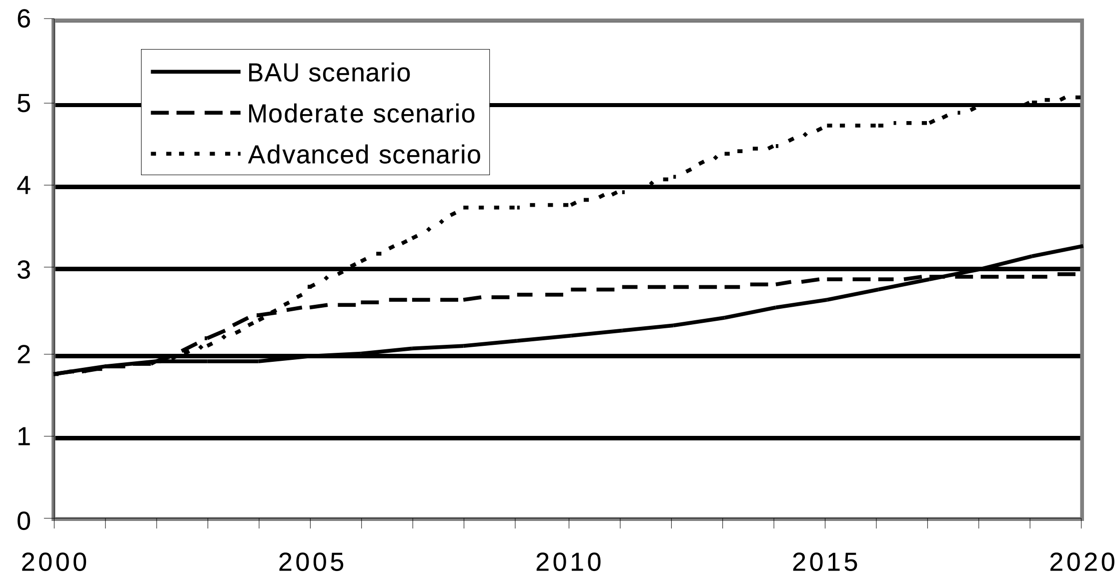
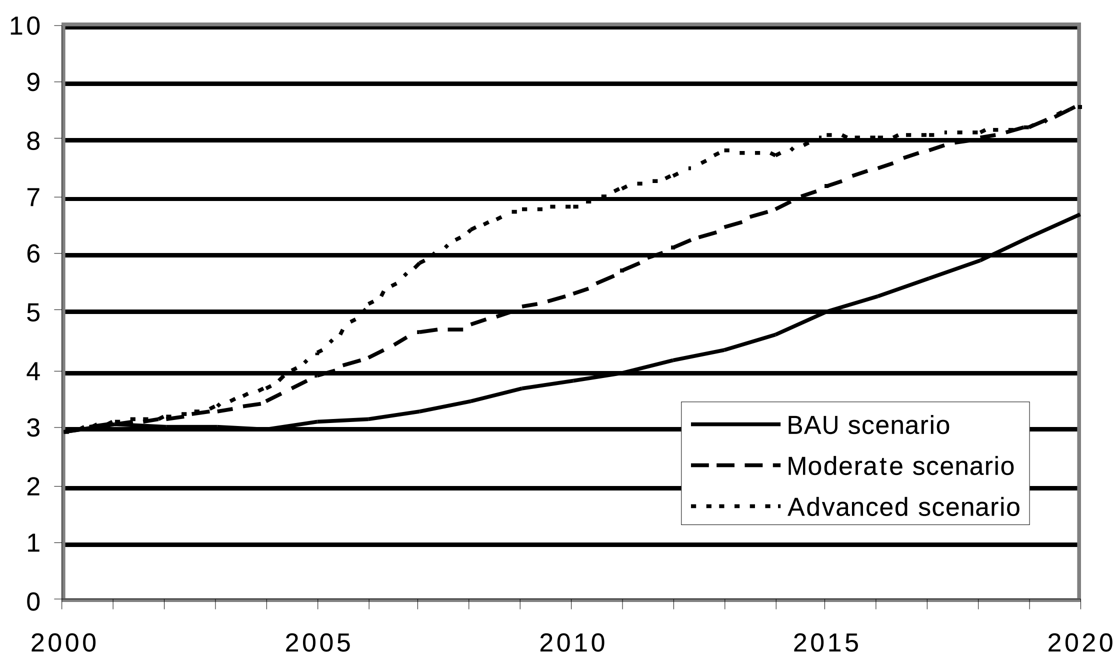


Fig. 7.9 Geothermal Capacity (GW)



7.4.2 BAU Scenario

The BAU scenario, as described above, has similar results to the AEO99 in total generation, but lower carbon emissions. Total generation by 2020 is 26 TWh lower and total generation capacity is 3 GW lower in the BAU scenario. These are less than 0.7% different from the AEO99 results. However, the mix of generation changed because of the change in the nuclear relicensing cost, biomass cofiring, and geothermal expansion described in section 7.3.1. Nuclear capacity in the BAU case in 2020 totaled 72 GW instead of the 49 GW in the AEO99 Reference case. Geothermal capacity increased from 3.5 GW to 6.7 GW. As a result, fossil and biomass capacities were reduced by 29 GW and total carbon emissions dropped 5.1%, from 745 MtC to 709 MtC.

Within the electric sector, no changes were made to the policies implemented within the AEO99. The major policies in AEO99 with regard to the electric sector are the Clean Air Act Amendments of 1990, the Energy Policy Act of 1992, EPA's Ozone Transport Rule for 22 Northeast and Midwest states, and electricity restructuring in five regions. These five regions are California, New York, New England, the Mid-Atlantic Area Council (consisting of Pennsylvania, Delaware, New Jersey, and Maryland), and the Mid-America Interconnected Network (consisting of Illinois and parts of Wisconsin and Missouri).

Besides nuclear relicensing costs, the main changes to the electric sector BAU scenario are in the modeling of wind, biomass cofiring, and geothermal as described above. The changes to wind had very little impact on the BAU scenario, because the changes mainly loosened constraints on the amount wind could grow. These constraints were not the limiting factor for wind in the BAU scenario. Biomass cofiring was not included in the AEO99 reference case, but is allowed in the BAU scenario of this study. While biomass use was higher in the years 1998-2017, by 2020 biomass use was higher in the AEO99 than in the BAU scenario. This is largely due to the increase in generation from nuclear power.

7.4.3 Moderate Scenario

The inputs for the Moderate scenario were altered to model the policies defined in section 7.2. The 1.5¢/kWh Production Tax Credit for wind and biomass through 2004, 1¢/kWh for biomass cofiring through 2004, complete restructuring of the national electricity market by 2008, and enhanced R&D programs were all included.

The Moderate scenario shows a 5% decline in primary fuel consumption by 2010 and 10% by 2020 as compared to the BAU scenario (Table 7.10). These are mainly due to the decrease in demand from the end-use sectors. (In this discussion, declines are relative to what the values are in the BAU scenario, not in absolute terms.) Total end-use demand declined by 6% and 12% in the two years, respectively (Table 7.9). Total carbon emissions declined 7% and 12% compared to the BAU scenario (Table 7.12). Overall capacity declined in response to the lower demand (Table 7.13), but most of the decline was in the combined cycle (down 65 GW in 2020) and combustion turbine (down 39 GW) capacities. Coal capacity only declined 5% or 15 GW, while nuclear capacity declined by 8 GW from the BAU amount. On the other hand, wind increased by 11 GW over the BAU case by 2020, to 15 GW because of the incentives and improved technologies.

SO_2 emissions remain at the cap in the Moderate scenario but the allowance price needed to keep emissions at the cap drops between 6% and 16% (Table 7.14). With lower demands and improved new technologies, it is easier to meet the limits so the market price of allowances declines. NO_x levels decline as well.

Fuel prices decline in the Moderate scenario versus the BAU scenario because of the lower demands (Tables 7.10 and 7.15). Similarly, electricity prices are down by 8% in 2010 and 4% in 2020.

7.4.4 Advanced Scenario

The Advanced scenario's inputs were modified to incorporate the additional changes described in section 7.2. In the Advanced scenario, demand for generation (not including cogeneration) is lower than the BAU scenario by 14% and 22% in 2010 and 2020, respectively (Table 7.9). As a consequence, primary fuel consumption declines 11% and 24% (Table 7.10), while carbon emissions decline 29% and 46% (Table 7.12). (In this discussion, declines are relative to what the values are in the BAU scenario, not in absolute terms.) These declines show the large impact of carbon allowances, improved technologies, and the renewable production tax credits. Coal-fired generation declines 51% by 2020 with capacity declining from 320 GW in the BAU scenario to 225 GW in the Advanced scenario (Tables 7.11 and 7.13). The average capacity factor of coal also drops from 77% (base load) to 54% (intermediate load) as carbon allowances raise the variable cost of coal production. Oil and gas average capacity factors increase from 32% to 42% since they are less affected by the carbon-related costs. This capacity factor would be higher, but with the increase in wind capacity, some of the gas capacity is used to firm the wind power and so might have a lower capacity factor.

The Advanced scenario has a more rapid advance in the average efficiency of gas-fired generation (Fig. 7.5). The average heat rate declines more quickly as 25 GW more combined cycle capacity is brought on in the years 2000-2005 than in the BAU scenario, while 6 GW of less-efficient combustion turbines are not built. An additional 10 GW of inefficient gas and oil-fired steam capacity is retired. Furthermore, the additions are more heavily weighted towards the advanced gas technologies. While in reality, some of the improvements in the advanced technologies would be incorporated into the conventional technologies, in these scenarios only the advanced technologies were improved. If the conventional technologies were changed as well, overall efficiency could be higher or lower than these results. Efficiency could be higher because more technologies would be improved, but lower because the improved conventional technologies may be more economic and displace some of the advanced technology that was added in this scenario.

The heat rate is further improved because of changes in the use of inefficient plants. With the advent of the carbon allowances requirement, inefficient gas and oil steam plants are used more infrequently and 10 GW are retired by 2005. By 2020, 47 GW more of these plants are retired than in the BAU scenario. Heat rates for new gas technologies decline further (approaching 70% efficient, or 4875 Btu/kWh, for combined cycle plants with fuel cells as a ternary cycle), but the average heat rate does not decline as much, reaching only 54% efficient by 2020.

Other air emissions (SO_2 and NO_x) are reduced in the Advanced scenario, compared to the BAU scenario (Table 7.14). SO_2 emissions (as a surrogate for PM emissions) were further restricted over the years 2011-2020, culminating in a 50% reduction from the BAU ceiling in the final year. Because of the lower demands and new technologies, the new ceiling was met with little increase in the permit price. Its highest value was $185/ton in 2016. An Advanced scenario sensitivity without the lowered ceiling had the permit price dropping to zero because emissions were below the existing ceiling by 2020.

Wind capacity grows to 16 GW installed by 2005, due in part to the PTC, carbon limits, and improving economics of wind. To conform with the requirements of the RPS, it continues to grow after the PTC expires, rising to 43 GW in 2010 and 47 GW in 2020. This growth represents over 34% of all new capacity built between 2005 and 2020 and 10% of capacity built post-2010.

Biomass use grows as well, both dedicated capacity and cofiring. Cofiring grows rapidly between 2000 and 2005, displacing approximately 1.8% of coal generation (Fig. 7.6). The 1¢/kWh cofiring production tax credit improves the cost-effectiveness of biomass between 2000 and 2014. Starting around 2005, the carbon allowance provides a similar inducement, especially since biomass directly displaces coal. Dedicated biomass generation grows slowly, but cofiring remains at relatively the same percentage of coal production. Consequently, as coal production declines, so does cofiring. Total non-cogeneration biomass production peaks in 2015 at 52 TWh, then declines to 48 TWh in 2020 (Table 7.11).

As shown by the demand sensitivity analysis of section 7.5.3, the generation from clean sources like renewables can be sensitive to the overall growth in electricity capacity. If the end-use demand policies of the Advanced scenario are not implemented or are not as effective as estimated here, larger electricity demand will spur additional electric capacity growth and more opportunities for clean energy supply technologies. Similarly, if advances in fossil generation technologies are not as much as expected in the two scenarios, wind capacity increases (Table 7.17).

7.5 DISCUSSION OF RESULTS

While electric sector-specific technologies and policies (discussed below) are important to the results, a critical factor is the change in non-cogenerating electricity demands by the buildings and industry sectors under the various scenarios (Fig. 7.1.) (Industrial cogeneration and district energy systems can play a large role in the reduction of electricity demand growth for this sector, providing from 70 to 120 GW of capacity that would otherwise need to be provided by this sector.) The electric sector is only a middleman in that it transforms energy from one form to another for use by others. While it may control the types of primary energy used to make electricity, the growth or lack of growth in demand plays an important role in the amount of primary energy and type of technologies used. Advanced technologies are limited to the relatively fixed amount of capacity expansion needed to meet demand over a given scenario plus any retirements. Incentives to accelerate their deployment have less success if demand growth is low, unless other incentives for accelerated retirement of existing capacity are also used.

Another critical factor that is external to the sector is the price of fuels (Table 7.15.) Coal prices stay relatively the same between the BAU and Moderate scenarios. In the Advanced scenario, the carbon permit value of $50/tC increases the price of coal by $1.30/MBtu. This raises the price by 120% to 145% and is a major cause in the lowering of coal use. Natural gas prices decline by 11% to 16% in the Moderate scenario because of a lowering of demand for gas in all sectors (12% by 2020). Even in the Advanced scenario including carbon allowances, prices rise only 13% in 2010 and by 2% in 2020 over the BAU scenario. Subtracting the carbon permit costs, the raw prices for gas drop significantly from the BAU prices.

7.5.1 Key Technologies

A number of changes were made to each of the production technologies. In the BAU scenario, wind, biomass cofiring, geothermal and nuclear plant modeling fundamentals were changed. In the Moderate scenario the most significant change happened to the renewable technologies. Capital and operating costs, and capacity factors were adjusted based on EIA's estimates of the High Technology scenarios of the AEO99. EIA's High Technology for fossil plants are largely devoted to lowering the cost of the technology rather than improving the efficiency. Capital costs in the Moderate scenario were lower based on EIA estimates of the impact of enhanced R&D. Values for renewables were largely unchanged between the Moderate and Advanced scenarios. Fossil technologies in the Advanced scenario includes more radical advances in fossil technologies such as ternary cycles for coal and gas combined-cycle plants. These raise the efficiency greatly by using a fuel cell as a front-end cycle before the other components. Carbon sequestration was also allowed within the model in conjunction with advanced fossil technologies after 2010 (through a $50/tC increase in operating cost.) However, the parameters for the advanced technologies differ most greatly from the Moderate scenario in the latter part of the study period. With overall demand relatively flat post-2010, there is less call for new capacity and less opportunity for these advances to make a significant impact (Fig. 7.1 and Table 7.13).

The importance of advanced coal technologies such as IGCC are largely dependent on the cost of fuel (including any carbon allowance cost) and overall demand. In the BAU scenario, 15 GW of IGCC is brought on-line by 2020, along with 5 GW of conventional coal. In the Moderate scenario, however, gas prices in 2020 are 13% lower than in the BAU scenario (due to lower gas demands); only 5 GW of IGCC and 1.6 GW of conventional coal are added. In the Advanced scenario demand is lower still and coal prices more than double due to the carbon allowance cost. No IGCC capacity is brought online and just the 1.4 GW of conventional coal that is already planned.

Of the renewable technologies, wind received the most benefit from improvements in technology and other policies. Its capacity in 2020 grows from 4 GW in the BAU scenario to 15 GW in the Moderate scenario to 47 GW in the Advanced scenario (Fig. 7.7). There is a large growth of wind through 2008 because of the PTC and the RPS (to 11 GW in the Moderate and 39 GW in the Advanced scenarios). In the Advanced scenario, economics (and the carbon permit costs) cause wind to continue to grow beyond these levels in later years. In the Moderate scenario additional growth is more modest.

PV also plays a role with penetration in buildings spurred by the Million Solar Roofs (MSR) Program at DOE and the adoption of net metering policies. The MSR has collected commitments for over 900,000 roof-top photovoltaics and active solar hot water units by 2010. These commitments are also a reflection of the public's interest in green power, a range of benefits associated with distributed generation, and the continuing improvement in the economics of solar technologies. In the CEF Advanced scenario, the economics of PV are improved by 2020 to the point that over 2.6 million PV rooftop systems are estimated to generate approximately 17 TWh/year. This trend could became a signficant factor in U.S. carbon reductions after 2020 as the technology continues to improve.

Geothermal capacity showed more rapid growth in the two policy scenarios, with capacity 38% to 77% higher by 2010 for the Moderate and Advanced scenarios, respectively (Fig. 7.9). However, growth in the BAU scenario continues at a steady pace such that the ratios of capacity between the three scenarios narrow.

7.5.2 Key Policies

The key policy driving the changes within the electric sector is the carbon allowance in the Advanced scenario. The carbon allowance plays a role in two ways. First, because of its larger impact on carbon-intensive fuels such as coal and inefficient oil and gas plants, no unplanned coal plants were added and 83 GW of coal capacity was retired by 2020 in the Advanced scenario. In addition, 112 GW of other fossil steam (oil and gas) were retired. (These compare to 20 GW of coal added and 6 GW coal and 68 GW of other fossil steam capacity retired in the BAU scenario.) Second, the carbon allowance directly impacts the variable cost of production, thereby causing the remaining carbon-intensive technologies to lower their capacity factor. Nuclear power better maintained its cost-effectiveness. Even without changes in the relicensing cost of nuclear power beyond that in the BAU scenario, the Advanced scenario had 11 GW more of nuclear power in 2020, with generation up 15%.

Sensitivity cases run for the Advanced scenario without the carbon allowance show 62% more generation from coal in 2020 than in the Advanced scenario, 22% less generation from gas, and 41% less generation from non-hydro renewables. Wind is the renewable energy form most impacted by the carbon cap, with capacity in 2020 lower by 55% (or 26 GW) without the cap.

Restructuring also plays a significant role but with potentially contrary impacts. By removing incentives for regulated utilities to retain capital investments that are no longer cost effective, deregulation creates incentives for inefficient coal or other plants to retire when carbon emissions are constrained and/or gas plants represent a more cost-effective option. (Economic retirements were allowed in all three scenarios.) At the same time, however, real-time pricing becomes a more important factor in the market, and the system load factor increases. This means that less-utilized plants (i.e. peakers and intermediate plants) may be called upon for a higher percentage of time and be more profitable. If coal plants are on the margin for a region, they will be used more. Less new capacity is needed to meet peak demands because of customer shifts in peak load requirements. In the Advanced scenario, while generation dropped 2.3% between 2010 and 2020, generation capacity declined by 3.7% (Table 7.11and Table 7.13).

As mentioned in the section above, the PTC (either as a policy in and of itself or as a surrogate for the RPS) plays an important role in the growth of renewable capacity. By creating growth in wind through 2004 or 2008, a strong base of capacity is developed that leads to further growth but at a slower pace after the PTC and RPS expire. In the Advanced scenario, wind generation grows by over 1700% between 2000 and 2008. Wind capacity represents 23% of all additions in that period, but accounts for a smaller 14% of the new capacity additions between 2008 and 2020. Since all capacity additions decline in this latter period, there is only a 20% growth of wind capacity post 2008 (Fig. 7.7). Geothermal and dedicated biomass capacity also see an impact from the PTC and RPS, but not as pronounced (Fig. 7.8 and 7.9). In the Advanced scenario they both roughly double through 2008 and then grow another 35% through 2020. In the Moderate scenario, where the PTC stops in 2004 and there is no carbon allowance nor RPS, growth is more modest. Wind roughly triples in that time. Biomass grows 40% during the PTC but only 20% from 2005 to2020. Geothermal, on the other hand, shows a more steady growth: 18% through 2004 and 150% more by 2020.

7.5.3 Uncertainties and Sensitivity Analyses

Sensitivity analyses are used to determine the impact of specific policies in connection with the basket of policies that define each scenario. The relative importance of the renewable portfolio standard, technology advances, and carbon allowances have been examined.

RPS Sensitivity. The RPS can have a significant impact. When we removed the surrogate RPS from the Advanced scenario (by not extending the PTC to from 2004 to 2008), generation by non-hydro renewables was only 5.3% of the total in 2010 (versus the prescribed 7.5%) and 6.9% in 2020 (versus 8.9% in the Advanced with RPS). Most of the reduction occurred in wind generation, which fell 39% from 159 TWh in 2020 to 97 TWh. The difference was even more dramatic in 2010 with generation down 54% between the two cases. However, this gives wind a smoother growth trajectory over the study period. Removing the RPS also decreased geothermal generation 9% in 2020 from 67 TWh to 61 TWh, and biomass (both biomass cofiring and biomass gasification) 4% from 48 TWh to 46 TWh. Without the RPS, both gas and coal generation increase, with coal showing a 7% increase in generation in 2020 compared to the Advanced scenario with the RPS. While significant renewables are still present without the RPS, it certainly increases generation from renewables, even beyond the RPS expiration date.

Fossil-fuel Technology Sensitivities. The technology advances used in these scenarios are based on projections by various experts of the potential cost and efficiency improvements. However, they are not necessarily what will occur; other experts have been more or less optimistic. Sensitivity analyses has been conducted to examine a less optimistic future for the cost and performance of IGCC and Gas CC plants. The parameters that were changed are listed in Table 7.16. Further explanation of the values is in Appendix C-4. Renewables were not modified in this sensitivity so are not included in the table. Table 7.17 shows the capacity, generation, and carbon emission changes for 2020 in the Moderate and Advanced scenarios that result when future improvements in these technologies are reduced.

Table 7.16 Fossil Technology Capital Cost and Heat Rate Sensitivities

	5th Plant Capital Cost (1997 $/kW)		Heat Rate (Btu/kWh)		
	Base	Sensitivity	Base	Sensitivity	Year for Heat Rate
IGCC Moderate	942	1000	8333-6968	8400-7500	2000-2010
IGCC Advanced	942	900	6440-5690	7449-6800	2010-2020
Gas CC BAU	405	475	6927-6350	7200-6800	2000-2015
Gas CC Moderate	348	450	6919-6255	6749-6200	2000-2015
Gas CC Advanced	348	425	5539-4874	6199-5700	2010-2020

As expected, gas combined cycle capacity shows the largest decrease in capacity and generation due to lower optimism with respect to the future improvements in gas combined cycle cost and performance improvements. Also as expected, competing technologies such as nuclear and renewables benefit when their competition costs more. Somewhat unexpectedly, carbon emissions are lower in 2020 as more nuclear remains on line and additional renewable capacity is built. Also, end-use demand for generation is reduced due to the slightly higher electricity prices. In the Moderate sensitivity, coal capacity declines slightly as less new capacity is added, while the Advanced sensitivity has higher coal production due to fewer retirements. With higher cost advanced technologies, the market price for SO_2 credits increases from $160/ton in the regular Advanced scenario to $173/ton in the Advanced sensitivity scenario in 2020. Electricity prices also increase over the regular scenarios by about 0.1-0.2¢/kWh in the Moderate and Advanced sensitivities. Because of the availability of advanced technologies for renewables and combustion turbines and the continued availability of relicensed nuclear plants as backstops, less R&D success for combined cycle and IGCC technologies does not have a major impact on the overall results.

Table 7.17 Changes in 2020 Capacity (GW), Generation (TWh), and Carbon Emissions (MtC) with Less Optimistic Projections of Future IGCC and Gas Combined Cycle Cost and Performance

Technology	Moderate Scenario		Advanced Scenario	
	GW	TWh	GW	TWh
Coal Steam	-2 (-1%)	-4 (0%)	+5 (2%)	+41 (0%)
Other Fossil Steam	+4 (7%)	Oil +1 (7%) Gas -90 (-11%)	-7 (-20%)	Oil 0 (0%) Gas -122 (-11%)
Gas Combined Cycle	-26 (-19%)		-36 (-24%)	
Combustion Turbine	+9 (6%)		+7 (5%)	
Nuclear	+8 (12%)	+56 (12%)	+2 (3%)	+16 (3%)
Wind	+3 (20%)	+11 (21%)	+10 (21%)	+29 (18%)
Biomass	+0.4 (15%)	+6 (21%)	+1 (24%)	+9 (18%)
Geothermal	+1 (12%)	+9 (13%)	+1 (11%)	+8 (12%)
End-Use Demand		-12 (0%)		-20 (-1%)
Carbon emissions (MtC)		-6 (-1%)		-3 (-1%)

Numbers in parentheses represent the percentage change compared to the basic Moderate and Advanced scenarios.

Renewable Technology Sensitivities. Another set of sensitivities was performed with higher renewable energy technology costs. Wind capital cost was raised 20% and biomass capital cost was raised 25%, based on the uncertainty range listed in the EPRI study *Renewable Energy Technology Characterizations*

(EPRI, 1997). As a consequence, wind capacity in the Advanced scenario declined 46% from 47 GW to 25 GW in 2020. Dedicated biomass declined 25%, from 5.1 GW to 3.8 GW (not including cogeneration.) Biomass cofiring remains slightly higher over time because of the increased availability of biomass and coal capacity, but overall biomass generation declined 15%, or 7 TWh. Coal-fired generation increased by 6%, or 69 TWh while gas generation increased 9 TWh. Because of the reduction in renewables and concomitant increase in fossil generation, carbon emissions were 20 MtC (5%) higher. Whereas in the fossil technology sensitivity above, non-fossil technologies buffered the carbon impact of less R&D success, the lack of R&D success for non-carbon renewables had a more pronounced impact on carbon emissions.

Carbon Trading Policy Sensitivity. Although the impact of carbon allowances was described in section 7.5.2 above, to further examine their importance we ran the Advanced scenario but without any carbon trading system, still keeping the other supply and demand policies. This makes a large impact on the use of coal; generation is 62% higher than in the Advanced scenario in 2020. Coal capacity is 29% higher, at 291 GW. This is still below the capacity in 1997, with only 3 GW added but 17 GW retired over the time period.

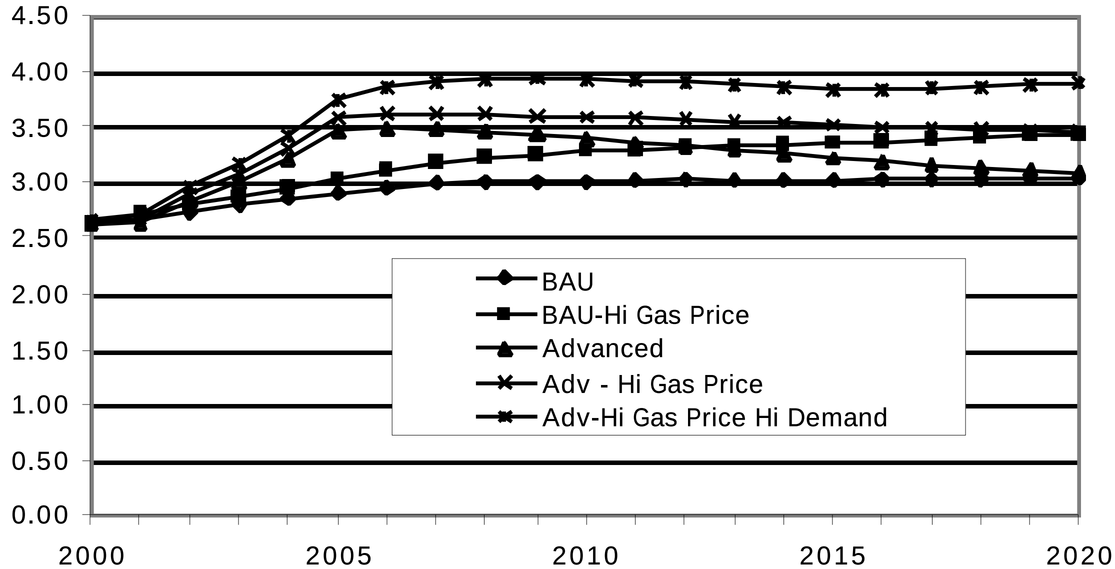
Natural gas, nuclear, and non-hydro renewables all have reductions in their generation by 20% to 30% as they are displaced by coal. Wind is hardest hit, with capacity reduced by 55% down to 21 GW. The 1.5¢/kWh PTC does not have the impact on renewable generation in that total generation by 2010 represents only 5.0% of generation, rather than 7.6%. This means that a RPS of 7.5% with a cap of 1.5¢/kWh would not reach the full portfolio standard level. Carbon emissions from the electric sector increase by 45% to 553 MtC. Overall demand increased by only 4% in 2010 and 3% in 2020 over the Advanced scenario, so the large increase in coal and carbon output are mainly due to the change in the relative price of fuels.

The SO_2 emissions cap policy is still in place so that emissions in 2020 are at 4.6 Mt SO_2, (SO_2 caps have been halved from the Phase II Clean Air Act Amendment requirements to reduce particulate matter emissions) This is 0.4Mt higher than in the Advanced scenario. In addition, the price of an SO_2 emissions allowance almost triples to $445/ton without the carbon trading system. The price of coal is $0.92/MBtu, $1.27/MBtu below the price in the Advanced scenario. However, this price is slightly above the Advanced scenario's price with the $50/tC carbon allowance fee removed. Electricity prices are lower, being only 5.2¢/kWh by 2020. This is lower by 0.9¢/kWh from the Advanced scenario, and is 0.4¢/kWh lower than the Advanced scenario even with the carbon fee removed from the fuel component (Table 7.15). One reason for this is the Advanced scenario had much more new construction, which increased the capital component of the electricity price by 0.3¢/kWh.

Gas Price Sensitivity. Because natural gas plays such an important role for new capacity, a set of sensitivities to modify the gas price were run on the BAU and the Advanced scenarios. CEF-NEMS does not allow the direct input of gas prices, so instead we reduced the technological progress to zero for oil/gas drilling/exploration and reduced technological progress rates by 50% for unconventional gas recovery and enhanced oil recovery. As a result, gas prices increase gradually till by 2020 they are about 12% or 38¢/MBtu higher (Fig. 7.10).

The most dramatic impact is on the amount of gas consumed, as expected. Gas consumption for electric generation is down by 12% to 13% by 2020 in the two sensitivities. In both cases, coal is used to make up most of the reduction in generation, 81% in the BAU and 72% in the Advanced sensitivity. Demand reduction is next and equals 10% of the reduction in gas generation in the BAU and 16% in the Advanced scenario sensitivity. Renewables have a larger impact in the Advanced sensitivity, replacing 12% of the lost gas generation, with 9% of that from added wind capacity (4 GW). In the BAU sensitivity, an additional 1.1 GW of nuclear is relicensed over the BAU scenario (making up 5% of the lost generation), but no new nuclear plants are built. The Advanced sensitivity sees no change in nuclear generation. Apparently, existing coal plants (non-retirement), energy efficiency, and renewable resources are the marginal supplies that are brought on if gas prices rise.

Fig. 7.10 Gas Prices to Electric Generators With and Without Restrictions on Technological Progress ($/MBtu)



An additional sensitivity was run to determine the impact if gas prices were raised as above and the end-use demand reduction policies were not put in place (as in the next sensitivity). These two factors combined raised the price of gas by 81¢/MBtu over the Advanced scenario, as shown in Fig. 7.10. Because of the increased demand, gas generation is 108 TWh higher than in the Advanced scenario, but this is 181 TWh (13%) lower than if gas prices are not adjusted (Table 7.18). As before, coal increases made up most (66%) of the gas reduction compared to the high demand scenario. Wind only increased to make up 4% of the lost gas generation, while biomass and geothermal made up 8% and 5% respectively. Since wind capacity was already very high at 63 GW due to the increase in demand, there was more opportunity for biomass (including cofiring) and geothermal to increase. Demand was higher by 524 TWh from the Advanced scenario but this is 30 TWh less than the scenario without demand reduction policies. Nuclear generation still did not change, since other technologies besides gas have lower costs and new nuclear still has a "lock-out" problem of high first plant costs due to the learning curve.

Demand Sensitivity. With the relatively flat electricity demand growth of the Advanced scenario, there is little demand for new electric capacity. This reduces the opportunities for clean energy supply technologies to enter the generation mix. We examined the impact of removing all the demand-side policies in the Advanced scenario. In this case, electricity demand is 16% greater in 2020 than in the Advanced scenario and, as shown by the percentage changes, non-hydro renewables and natural gas generation are impacted proportionately more than coal. However because the other clean sources, nuclear and hydro, are not impacted, the overall carbon impact is almost directly proportional to the energy impact.

Table 7.18 2020 Demand Reduction and High Gas Impacts in the Advanced Scenario (TWh) (w/o cogeneration)

	Advanced scenario	Advanced minus demand policies	Advanced minus demand policies plus hi gas prices
Electricity Demand	3442	3996 (+16%)[a]	3966 (+15%)[a]
Coal Generation	1065	1213 (+14%)	1333 (+36%)
Gas Combined Cycle Generation	1134	1428 (+25%)	1247 (+9%)
Non-hydro Renewables Generation	306	420 (+37%)	449 (+47%)
Nuclear and Hydro generation	923	924 (0%)	923 (0%)
Electric Sector Carbon (MtC)	382	440 (+15%)	460 (+20%)

[a]Percentage change from the Advanced scenario

Nuclear Sensitivities. One reason for the lack of penetration of new nuclear capacity is the capital cost of new technology. Learning from experience may eventually make plants cost-competitive, but the cost of the first plant precludes their development. This has been called “lock-out” (EIA, 1999). In CEF-NEMS there are two factors that raise the capital cost of the first plants, as compared to the fifth-of-a-kind plant that is entered. One is the Technical Optimism factor, a parameter in CEF-NEMS that raises the cost of the first nuclear plant by 19% above the input fifth-of-a-kind plant cost, decreasing with subsequent plants. For the Moderate and Advanced scenarios we removed this factor, justifying the removal by assuming a policy of joint development with other nations so that plants elsewhere in the world provided the technical knowledge to avoid the increase. The second factor is the Learning Curve factor, which raises the first plant's capital cost by an additional 28% with subsequent plants having a lower factor. The Learning Curve factor continues to lower the cost of plants beyond the fifth as capacity grows. Combined, the two factors in the BAU scenario make the first plant 52% higher in cost than the fifth one built. The Moderate scenario still had a first plant's cost 28% higher than the fifth. Even the Advanced scenario had the first plant 28% higher than the fifth one, but all had a 10% cut in the capital cost compared to the BAU. In none of these scenarios were nuclear plants built.

As a sensitivity to the Advanced scenario, we removed the Learning Curve factor for the first four advanced nuclear plants (in addition to the Advanced scenario's 10% reduction in capital cost and removal of the 19% technical optimism factor.) This removal could be reflective of a policy of subsidizing the construction cost of the first four plants to make them have the same cost as the fifth one. We also slightly modified the construction schedule so that costs are spread more evenly over the plant’s construction period. These changes succeeded in lowering the average capital cost of the first plant from $1822/kW to $1427/kW in 1997$. However, this still did not make nuclear cost-competitive with advanced gas combined cycle plants or wind capacity (with the production credit). The national average levelized cost for nuclear capacity in the 2005-2010 time-frame was $39/MWh, while advanced gas CC plants had a peak cost of around $35/MWh in 2006 that then declined over time. In three regions of the country (California/Nevada, Rocky Mountains, and Florida) nuclear capacity had lower costs than gas CC for one or more years between 2004 and 2008. However, during those years renewable incentives were in place and in these regions wind or geothermal capacity were the lowest cost options. Consequently, the renewable technologies were selected instead of gas or nuclear.

A further sensitivity was run with the same nuclear costs as above but with higher end-use demands and gas prices (as described in the previous two sensitivities.) While gas CC plants did increase in cost, the change was not as high as expected. (Total cost rose 5%-15% by 2020 depending on region, despite a 25% increase in gas price.) Gas capacity expansion was lower than before, but other technologies (wind, biomass, geothermal, and non-retirement of existing coal plants) were still used instead of new nuclear plant construction.

As a further analysis of the cost of new nuclear technologies in comparison to gas-fired combined cycle, the two were compared in a series of cases outside of the CEF-NEMS model by varying their fuel price, capital costs, and efficiencies for the year 2020. A cost model comparing the life-cycle cost was used that has previously been used in analyses of future technology cost comparisons (Delene, et al., 1999). A reference nuclear plant was defined with values similar to those of the CEF-NEMS runs, and a consequent levelized cost of $44.6/MWh. (The levelized costs in 2020 for a fifth-of-a-kind plant from the BAU, Moderate, and Advanced scenarios were around $46, $45, and $41/MWh, respectively.) A reference gas combined cycle plant was defined that had a lower efficiency (50%) and higher capital cost ($615/kW) than that used in the Advanced scenario, resulting in a levelized cost of $36.6/MWh. In addition to calculating the levelized costs for comparison of the two technologies, the cost model was used to estimate a breakeven carbon allowance cost. For the reference cases, a carbon allowance charge of $80.4/tC will equalize the cost of the nuclear and gas combined cycle plants. Table 7.19 shows the results for the various cases.

The reference case uses a gas price of $3.24/MBtu, as in the 1999 AEO. Case 3 uses a gas price of $3.63/MBtu, from the High Economic Growth case in the 1999 AEO. Cases 2 and 4 are similar to Cases 1 and 3 except the price of gas was assumed to escalate at 0.8% and 1.3% above inflation for the subsequent years. Case 5 shows the impact of reducing the capital cost of the nuclear plant by 10%, as in the Advanced scenario. Case 6 represents the gas technology for 2020 as in the Advanced scenario, with a heat rate of 4874Btu/kWh (70% efficient). Gas prices match the Advanced scenario price of $2.36/MBtu (not including the carbon charge.) The final case shows the levelized cost of an advanced pressurized fluidized bed combustor using coal. More details on the parameters and results can be found in Appendix E-8.

Table 7.19 Sensitivity Analysis of Nuclear and Gas Levelized Costs

	Levelized Cost ($/MWH)		Breakeven Carbon Charge ($/tC)
	Nuclear	Gas CC (or Coal PFBC) [a]	
1. Reference	44.6	36.6	80.4
2. Gas price escalated post-2020 at 0.8%	44.6	38.9	56.9
3. EIA AEO99 high economic growth gas price	44.6	39.3	52.8
4. EIA AEO99 high growth plus 1.3%/yr gas escalation	44.6	43.8	8.0
5. Case 4 plus 10% reduction in nuclear capital cost	41.6	43.8	-21.8
6. CEF Advanced scenario gas price and CC technology	44.6	25.4	272
7. Coal-fired PFBC instead of Gas CC	44.6	37.5	33.8

[a] The levelized price for the fossil technologies do not include any cost for a carbon charge.

The results show the sensitivity to gas prices, capital costs, plant efficiencies, and escalation rates, at the same time showing that there are a combination of factors that would make nuclear power more economic than gas CC. If gas prices rise (due either to supply and demand and/or carbon charges), and technology advances for combined cycle plants don't occur, then an advanced nuclear plant can be competitive. However, if gas CC can reach its efficiency targets, then nuclear power may find it difficult to compete.

Also, other supply sources such as renewables and demand reductions through efficiency provide additional competition in the energy marketplace.

7.5.4 Policy Costs

Estimating the costs of policies in the electric sector is complicated by the fact that the electricity demand varies considerably between the different scenarios. The total electricity bill in the Moderate scenario is considerably less than that of either the BAU or the Advanced scenarios, as shown in Table 7.20. This is due to a reduction in demand and the absence of a cost for carbon allowances. The cost per kWh is also less in the Moderate scenario than in the BAU scenario due largely to the decrease in the cost of natural gas to the electric sector that results from lower gas demand in the end-use sectors. Similarly, the total national electric bill is less in the Advanced scenario than in the BAU scenario because of the lower electricity demand. However the cost per kWh in the Advanced scenario is higher than that of either of the other scenarios largely because of the cost of carbon allowances, which are $50/tonne from 2005 through 2020.

We have also approximated the direct energy costs of the more significant individual policies. The cost of carbon allowances to electric generators in the Advanced scenario is $23 billion per year in 2010 and falls slightly to $19 billion/year in 2020 with reductions in carbon emissions. These carbon allowance costs are also reflected in the total national electricity bill and represent about 10% of that bill. The cumulative undiscounted cost over the years 2005 through 2020 is $352 billion. There is no carbon allowance cost in the BAU or Moderate scenario because there is no assumed carbon trading system in those scenarios. Clearly, the carbon allowance cost is the highest cost policy for the electric sector. However, much of these costs would be recycled back into the economy depending on the design of the carbon trading mechanism. This is further discussed in Section 1.4.5.

The cumulative undiscounted cost over the years 2000 through 2018 of the renewable energy PTC was estimated to be $5 billion and $30 billion in the Moderate and Advanced scenarios, respectively. (The Advanced scenario extended the PTC as a surrogate of an RPS.) The cost in the Advanced scenario is appreciably larger because the credit is assumed to apply to all non-hydro renewables (not just wind and biomass as in the Moderate case), because the credit applies to capacity built through 2008 and cofiring through 2014, and because the carbon trading program in the Advanced scenario encourages more renewable energy. Table 7.20 shows the cost for the specific years of 2010 and 2020. While the credit is assumed to be available only to renewable energy generators constructed between 2000 and 2008 (2004 in the Moderate scenario), those plants are assumed to receive a credit for the first 10 years of production. Thus the annual costs shown in Table 7.20 for the year 2010 are non-zero. All plants receiving the credit have completed their first 10 years of production by 2020, so Table 7.20 shows no annual cost for that year.

The electricity-specific incremental cost of R&D programs has not been estimated in this chapter. The R&D expenditure increases are consolidated in the overall analyses (chapters 1 and 2) and are not broken out by sector. Clearly, some R&D investments would only help the electricity sector (e.g., nuclear, wind), but others (e.g., biomass, fuel cells, microturbines) would help more than one.

Use of a PTC as a surrogate for the RPS gives higher costs than the RPS as proposed by the administration. It matches the ceiling cost that the administration proposal includes, but effectively costs out all renewables at that ceiling price. In reality, some of the renewables will cost less, incrementally, than 1.5¢/kWh above the marginal cost of production. Some are economical without any credit, which is often described as the “free rider” problem; production that is economic without any subsidies receives them anyway. Another reason that the costs shown in Table 7.20 are slightly higher than an RPS is that the percentage of production from renewables in 2010 is 7.6% of total non-cogeneration production, which is higher than the proposed 7.5%.

These costs do not include a systems benefit charge that may be added to all electrical sales. This charge is collected by state organizations to assist in funding energy efficiency or other energy-related public benefits programs.

Additional administrative and macroeconomic costs to the economy as a whole associated with the policies evaluated in the electric sector are addressed in Chapter 8.

Table 7.20 Annual Cost of Policies in the Electric Sector (1997$)

		2010			2020		
	1997	**BAU**	**Mod.**	**Adv.**	**BAU**	**Mod.**	**Adv.**
Total electricity bill ($B/yr)	216	234	202	227	238	198	207
Cost per kWh (cents/kWh)	6.9	6.1	5.6	6.6	5.5	5.3	6.1
Carbon allowance payments $B/yr)	0	0	0	23	0	0	19
Production tax credit cost ($B/yr)	0	0	0.4	0.6	0	0	0
Renew Portfolio Standard ($B/yr)[a]	0	0	0.0	2.2	0	0	0

Note: BAU = Business-as-Usual scenario; Mod. = Moderate scenario; Adv.= Advanced scenario.

[a] Cost shown is the incremental cost for extension of the PTC to 2008 and the biomass cofiring credit to 2014.

7.6 CONCLUSIONS

In the Advanced scenario carbon emissions from the electric sector are substantially reduced from those of the BAU scenario – 29% in 2010 and 46% in 2020. Just under half of this reduction is due to lower demand for electricity as a result of efficiency improvements in the end-use sectors. While in the Advanced scenario demand fell 22% by 2020, fossil fuel use declined 42%, mostly (37% points) due to reductions in coal use. The difference is made up by nuclear and non-hydro renewables, which were 15% and 40%, respectively, larger than in the BAU scenario

The carbon reductions (relative to the BAU) in the electric sector in the Moderate scenario are considerably more modest – 7% in 2010 and 12% in 2020. Without a carbon trading policy in the Moderate scenario, the reduction in demand for electricity relative to the BAU was met almost entirely by not building new gas-fired generators. Consequently, in 2020 there is slightly more carbon produced per kWh in this scenario than in the BAU. The reduction in new gas generation more than offset the impact on carbon from using 8% less coal and 41% more generation from non-hydro renewables.

These results highlight the importance of the carbon trading policy. Without it we don’t see the reductions in coal usage, nor the construction of new gas fired plants. The carbon trading policy works together with the R&D-driven technology improvements, RPS and the production tax credit for renewables to significantly increase renewable generation, primarily wind, in the Advanced scenario. While the carbon trading policy does increase the average price per kWh of electricity, the electricity bill is actually smaller in both the Moderate and Advanced scenarios than in the BAU due to reductions in the demand for electricity.

7.7 REFERENCES

Coal Utilization Research Council, 1998, *Incentives for Clean Coal Technology Research and Development and Deployment Program* (May).

Delene, J. G., J. Sheffield, K.A. Williams, R. L. Reid, S. Hadley 1999, *An Assessment of the Economics of Future Electric Power Generation Options and the Implications for Fusion*, ORNL/TM-1999-243, Oak Ridge National Laboratory, September.

DOE Hydropower Assessment Program, http://www.inel.gov/national/hydropower/state/stateres.htm

DOE National Laboratory Directors, 1997, *Technology Opportunities to Reduce U.S. Greenhouse Gas Emissions*, http://www.ornl.gov/climate_change/, September.

Dye, Richard, Office of Fossil Energy, U.S. Department of Energy, personal communication, March 12, 1999.

EPRI (Electric Power Research Institute) and Office of Utility Technologies, Energy Efficiency and Renewable Energy, 1997, *Renewable Energy Technology Characterizations*, EPRI TR-109496, U.S. Department of Energy, Washington, DC, December.

EPRI, 1999, "Powering Up Superconducting Cable," *EPRI Journal*, Electric Power Research Institute, Palo Alto, CA, Spring.

EIA (Energy Information Administration) 1998a, *Annual Energy Outlook 1999 with Projections to 2020*, DOE/EIA-0383(99), http://www.eia.doe.gov/oiaf/aeo99/homepage.html, U.S. Department of Energy, Washington, D.C. December.

EIA (Energy Information Administration) 1998b, *Assumptions to the Annual Energy Outlook 1999 with Projections to 2020*, DOE/EIA-0554(99), http://www.eia.doe.gov/oiaf/assum99/introduction .html, U.S. Department of Energy, Washington, D.C., December.

EIA (Energy Information Administration) 1999, *Issues in Midterm Analysis and Forecasting 1999*, EIA/DOE-0607(99), U.S. Department of Energy, Washington, D.C. August.

EPA (Environmental Protection Agency) 1999, *Analysis Of Emissions Reduction Options For The Electric Power Industry*, Office of Air and Radiation, U.S. Environmental Protection Agency, Washington, DC, March. <http://www.epa.gov/capi/multipol/mercury.htm>

Federal Energy Regulatory Commission (FERC), 1988, *PURPA benefits at new dams and diversions. Final Staff Report*, Federal Energy Regulatory Commission, Office of Hydropower Licensing, Washington, D.C.

Hunt, R.T., and J.A. Hunt. 1997. *Hydropower resources at risk: the status of hydropower regulation and development 1997*. Richard Hunt Associates, Inc., Annapolis, Maryland, July.

Kaarsberg, Tina, Julie Fox Gorte and Richard Munson, "The Clean Air-Innovative Technology Initiative Link: Enhancing Efficiency in the Electricity Industry," Northeast-Midwest Institute Press, Washington, D.C., December, 1999. <http://www.nemw.org/tinabook.htm>

Kline, David and John "Skip" Laitner, 1999, "Policies to Enhance Technology Diffusion and Market Transformation," forthcoming in *Proceedings of the 20th Annual North American Conference*, U.S. Association for Energy Economics and International Association for Energy Economics, August.

Office of Fossil Energy, 1999, *Coal and Power Systems: Strategic Plan & Multi-Year Program Plans*, U.S. Department of Energy, Washington, D.C., January.

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

Parsons Power Group Inc., 1998, *Decarbonized Fuel Production Facilities including 1. Baseline Plant with ATS Expander and FGD, 2. Plant to Produce Syngas from Coal and 3. Baseline Plant with Transport Gasifier*, Draft Letter Report, Office of Fossil Energy, U.S. Department of Energy, Washington, DC, September.

Rinehart, B. N., J. E. Francfort, G. L. Sommers, G. F. Cada, and M. J. Sale, 1997, *DOE Hydropower Program biennial report 1996-1997*, DOE/ID-10510, U.S. Department of Energy, Idaho Falls Operations Office, Idaho Falls, ID.

South, D.W., K.A. Bailey and E. Bodmer, 1995, *Analysis of Incentives to Accelerate First-of-a-Kind (FOAK) Clean Coal Technologies*, prepared for U.S. Department of Energy (October).

Spencer, D.F, 1996, *An Analysis of Cost Effective Incentives for Initial Commercial Deployment of Advanced Clean Coal Technologies*, prepared for U.S. Department of Energy (May).

Spurr, Mark, 1999, *District Energy Systems Integrated with Combined Heat and Power*, Washington, DC: prepared for the U.S. Environmental Protection Agency by the International District Energy Association, March.

Wiser, Ryan, Jeff Fang, Kevin Porter, and Ashley Houston,1999, *Green Power Marketing in Retail Competition: An Early Assessment*, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-42286, National Renewable Energy Laboratory, NREL/TP.620.25939, February.
http://www.eren.doe.gov/greenpower/wiser_emaa.html