# 4. Electricity Supply

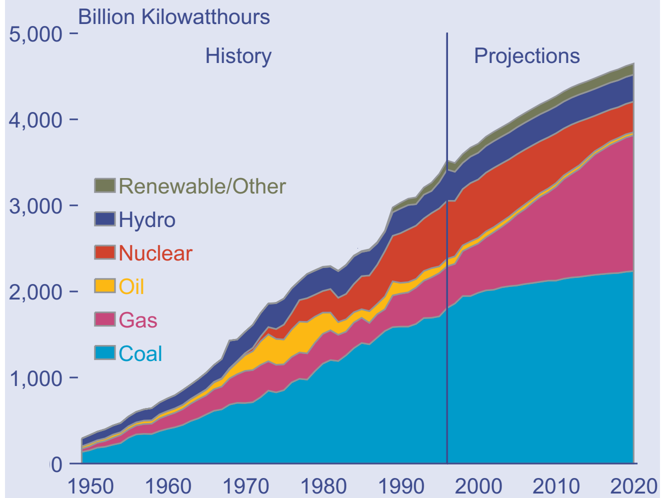
## Introduction

This chapter discusses the electricity supply side options under various domestic carbon emissions reduction cases, particularly the 24-percent-above-1990 (1990+24%), 9-percent-above-1990 (1990+9%) and 3-percent-below-1990 (1990-3%) cases. The impacts on electricity sector fuel use, capacity expansion and retirement decisions, electricity prices, and carbon emissions are discussed. In addition, the results of sensitivity cases incorporating alternative assumptions about improvements in technology costs and performance, the potential role for new nuclear power plants, and reducing impacts on the coal industry are also discussed. The effects of demand-side decisions (i.e., consumer appliance choices and usage, as discussed in Chapter 3) that would reduce the demand for electricity are also considered.

During the approximately 100-year history of the electricity supply industry, the key fuels used to meet the ever-increasing demand for electricity have changed as new generating technologies have emerged and fuel prices varied (Figure 65). Beginning with small hydroelectric facilities just before the turn of the century, the industry then turned to fossil fuels. Among the fossil fuels, coal has almost always played a major role in U.S. electricity generation, and it remains the dominant fuel today. Oil and natural gas use has varied, depending on their respective prices. In fact, concerns about future oil and natural gas prices contributed to the emergence of nuclear power plants in the 1960s. In today's market, coal-fired power plants produce just over half of the electricity used in the United States, nuclear plants 19 percent, natural gas plants 14 percent, and hydroelectric plants about 10 percent. The remaining 7 percent comes from oil-fired plants and plants using other fuels such as municipal solid waste, wood, and geothermal and wind power.

In the reference case, which does not include the Kyoto Protocol, the power generation sector is expected to become more energy-efficient over the next 20 years as new, more efficient power plants are built. At the same time, however, dependence on fossil fuels, especially natural gas and coal, is expected to increase, leading to significant growth in power plant carbon emissions. Coal is expected to remain the dominant fuel as existing plants are used more intensively, but generation from

**Figure 65. Electricity Generation by Fuel in the Reference Case, 1949-2020**



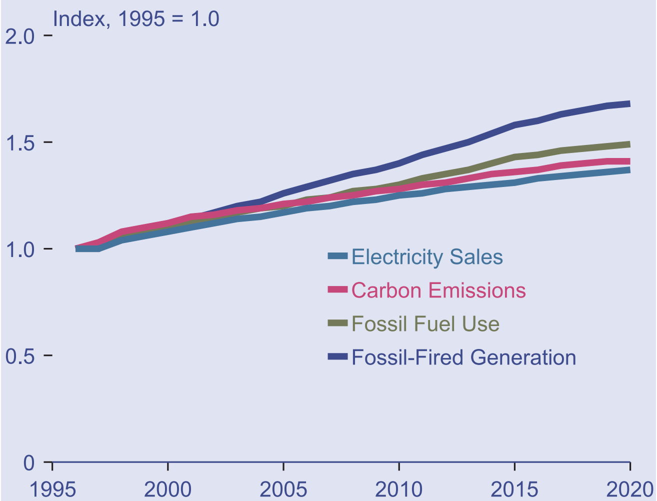

Note: Data on nonutility generation are not available for years before 1989, but it was small. In 1989, nonutility generation accounted for 6 percent of total U.S. electricity generation.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

natural gas is expected to increase rapidly, with gas-fired plants making up the vast majority of new capacity additions. Of the major non-carbon-based fuels, hydroelectric generation is expected to change very little, and nuclear generation is expected to decline as older, more costly plants are retired. Looked at another way, while the efficiency of the generation sector, expressed as the amount of energy in terms of British thermal units (Btu) needed to produce each kilowatthour of electricity, is expected to improve, increasing dependence on fossil fuels will lead to more rapid growth in electricity sector carbon emissions than in electricity sales (Figure 66). Without the improvement in efficiency, growth in fossil fuel use would match the growth in fossil-fired generation.

Although the costs of non-carbon-based generating technologies have fallen, they still are not widely competitive with fossil fuel technologies. As a result, the most economical options available to electricity suppliers for meeting the demand for electricity over the next 20 years are existing coal plants and new natural gas plants. In 1995, the average operating cost of coal-fired power plants was 1.8 cents per kilowatthour. Only

**Figure 66. Projections of Electricity Sales, Carbon Emissions, Fossil Fuel Use, and Fossil-Fired Generation, 1997-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run KYBASE.D080398A.

66 percent of their maximum potential output was needed, however, to meet the 1996 level of demand. Over the next 20 years, as the demand for electricity grows, the utilization of coal-fired plants is expected to approach 80 percent. For new capacity additions, the low capital costs and high operating efficiencies of natural-gas-fired combined-cycle plants make them the most economical choice for most uses.

Electricity suppliers have a variety of options available for reducing their carbon emissions. The degree to which each of the options is employed will depend on the level of reduction required and the resultant carbon price (i.e., the market value of a "carbon emissions permit") that evolves in the marketplace. Many of the options may require a significant financial incentive before they become economically attractive. Among the key carbon reduction options available to electricity suppliers are reducing the use of relatively carbon-intensive power plants (particularly coal-fired plants), increasing the use of less carbon-intensive technologies (mainly natural-gas-fired plants), the use of "carbon-free" technologies (i.e. wind, solar, biomass, geothermal, and nuclear), improving the operating efficiencies of existing plants, and investing in demand-side technologies that reduce electricity consumption.

In the short run, before a large number of new plants can be built, power suppliers will have to reduce carbon emissions by increasing the use of less carbon-intensive plants. For example, in today's market, most oil and natural gas steam plants are not used very intensively because of their relatively high operating costs. If carbon reduction efforts are made, however, their use is likely to increase, because they produce less carbon per kilowatthour than do coal-fired plants. In the longer run, power suppliers are more likely to turn to new, less carbon-intensive or carbon-free plants.

In this analysis, electricity producers are assumed to have 15 new generating technologies to choose from when new resources are needed, or when it is no longer economical to continue operating existing plants (Table 16). The lead times in the tables represent the time needed for site preparation and construction. Environmental licensing may take longer in some cases. The first-of-a-kind costs represent the cost of building a plant when the technology first becomes available, which tend to be relatively high until experience is gained with the technology. The *n*th-of-a-kind costs represent costs for technologies when they have matured. For technologies that are already considered mature, the two costs will be the same. Investors in the generation market are assumed to make their decisions by reviewing each technology's current and future capital, operations and maintenance, and fuel costs. Both current and expected future costs are considered, because generating assets require considerable investment and last many years. Therefore, developers are assumed to evaluate the costs of building and operating a plant for 30 years when making their decisions.[54] If the Kyoto Protocol is enacted, developers will also have to consider the relative level of carbon emissions from each technology, as well as the expected carbon prices. Depending on the carbon price, the economic decision could be tilted toward technologies that emit less carbon per unit of electricity produced.

Overall, because of the relatively wide variety of options available to them, electricity suppliers are expected to account for a disproportionately large share of projected carbon reductions. Nationally, to meet an emissions target 9 percent above 1990 levels, overall carbon emissions in 2010 would have to be reduced by 18 percent from their projected level in the reference case, which is 33 percent above 1990 levels. But in order to meet the target, emissions from the electricity sector in the 1990+9% case are reduced by 39 percent in 2010 relative to the reference case (Figure 67). The situation is similar in the 1990-3% case: electricity sector carbon emissions in 2010 are 54 percent lower than the reference case level. The reduction in carbon emissions is projected to be accomplished through a combination of fuel switching, improvements in end-use efficiency, and improvements in generator efficiency (Figure 68).

In the carbon reduction cases, carbon emissions in the electricity sector are projected to begin falling even before the enactment of the Kyoto Protocol, because power plant developers are assumed to consider future costs in their investment decisions. As the implementation date of the Kyoto Protocol approaches, it is assumed

[54]Capital costs are assumed to be recovered over the first 20 years of this period.

## Table 16. Cost and Performance Characteristics of New Fossil, Renewable, and Nuclear Generating Technologies

| Technology | Size (MW) | Lead Time (Years) | First Electricity Date | Overnight Capital Cost[a] (1996 Dollars per kWh) | | Variable O&M (1996 Mills per kWh) | Fixed O&M (1996 Dollars per kW) | Heat Rate (Btu per kWh) | | Carbon Emissions (Pounds per MWh) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | First-of-a-Kind | *n*th-of-a-Kind | | | First-of-a-kind | *n*th-of-a-Kind | |
| Pulverized Coal (95% Scrubber) | 400 | 4 | 2001 | 1,079 | 1,079 | 3.25 | 22.5 | 9,585 | 9,087 | 519 |
| Advanced Coal (IGCC) | 380 | 4 | 2001 | 1,833 | 1,206 | 1.87 | 24.2 | 8,470 | 7,308 | 417 |
| Oil/Gas Stream (Conventional) | 300 | 2 | 1998 | 991 | 991 | 0.5 | 30.0 | 9,500 | 9,500 | 296 |
| Combined-Cycle (Conventional, F-Frame) | 250 | 3 | 2000 | 440 | 440 | 2.0 | 15.0 | 8,030 | 7,000 | 250 |
| Combined-Cycle (Advanced, G- & H-Frame) | 400 | 3 | 2000 | 572 | 400 | 2.0 | 13.8 | 6,985 | 6,350 | 198 |
| Combustion Turbine (Conventional) | 160 | 2 | 1999 | 325 | 325 | 5.0 | 4.0 | 11,900 | 10,600 | 330 |
| Combustion Turbine (Advanced Turbine System) | 120 | 2 | 1999 | 458 | 320 | 5.0 | 5.7 | 9,700 | 8,000 | 249 |
| Fuel Cell (Molten Carbonate) | 10 | 2 | 2003 | 2,189 | 1,440 | 2.0 | 14.4 | 6,000 | 5,361 | 167 |
| Nuclear (Evolutionary Advanced Reactor) | 1,300 | 5 | 2010 | 2,356 | 1,550 | 0.4 | 55.0 | 10,400 | 10,400 | 0 |
| Biomass | 100 | 4 | 2005 | 2,243 | 1,476 | 5.2 | 43.0 | 8,911 | 8,224 | 0 |
| Geothermal[b] | 50 | 4 | 1996 | NA | 2,025 | 0.0 | 95.7 | 32,391 | NA | 0 |
| Municipal Solid Waste[c] | 30 | 1 | 1995 | 6,403 | 5,289 | 5.4 | 0.0 | 16,000 | 16,000 | 0 |
| Solar Thermal[d] | 100 | 3 | 2000 | 2,903 | [e]1,910 | 0.0 | 46.0 | NA | NA | 0 |
| Solar Photovoltaic | 5 | 2 | 1997 | 4,556 | [e]3,185 | 0.0 | 9.7 | NA | NA | 0 |
| Wind | 50 | 3 | 1997 | 1,235 | 965 | 0.0 | 25.6 | NA | NA | 0 |

[a]Overnight capital cost plus project contingencies.
[b]Because geothermal cost and performance parameters are specific for each of the 51 sites in the database, the value shown is an average for the capacity built in 2000.
[c]Because municipal solid waste does not compete with other technologies in the model, these values are used only in calculating the average costs of electricity.
[d]Solar thermal is assumed to operate economically only in Electricity Market Module regions 2, 5, and 10-13, that is, West of the Mississippi River, because of its requirement for significant direct, normal insulation.
[e]Capital costs for solar technologies are net of (reduced by) the 10 percent investment tax credit.
kW = kilowatt. kWh = kilowatthour. MW = megawatt. MWh = megawatthour. NA = not available. O&M = operations and maintenance costs.
Sources: Most values are derived by the Energy Information Administration, Office of Integrated Analysis and Forecasting from analysis of reports and discussions with various sources from industry, government, and the National Laboratories, with the following specific sources: **Solar Thermal**—California Energy Commission Memorandum, *Technology Characterization for ER94* (August 6, 1993). **Photovoltaic**—Electric Power Research Institute, *Technical Assessment Guide*, EPRI-TAG 1993. **Municipal Solid Waste**—EPRI-TAG 1993.

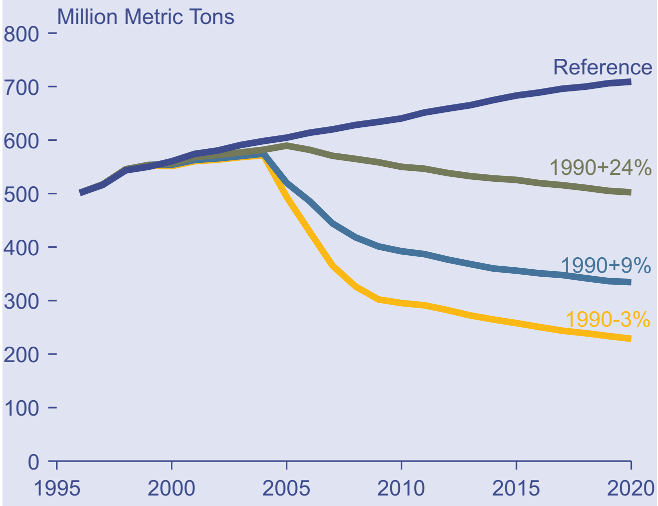
that developers will incorporate their expectations of carbon prices into their plans for new capacity additions, and that more lower-carbon generating capacity will be brought on line than would have been in the absence of the expected carbon reduction mandate.

## Trends in Fuel Use and Generating Capacity

To reduce power plant carbon emissions in the 1990+9% case, the mix of fuels used to produce electricity is expected to change significantly from historical patterns (Figure 69). The change required is possible, but it will be challenging. For example, the shift required to stabilize carbon emissions 9 percent above 1990 levels is unprecedented historically. Even during the 1960s and 1970s, when nuclear generation grew rapidly, the change in fuel use patterns was not as dramatic as would be required in this case. In the 1990+24% case, the shift is less pronounced, but coal-fired generation still is projected to be 17 percent lower in 2010 and 40 percent lower in 2020 than in the reference case. Across the carbon reduction cases, the projections show a consistent shift away from coal to natural gas and renewables for electricity generation. In addition, nuclear generation remains near current levels, and the demand for electricity falls as the carbon reduction goal tightens (Figure 70).

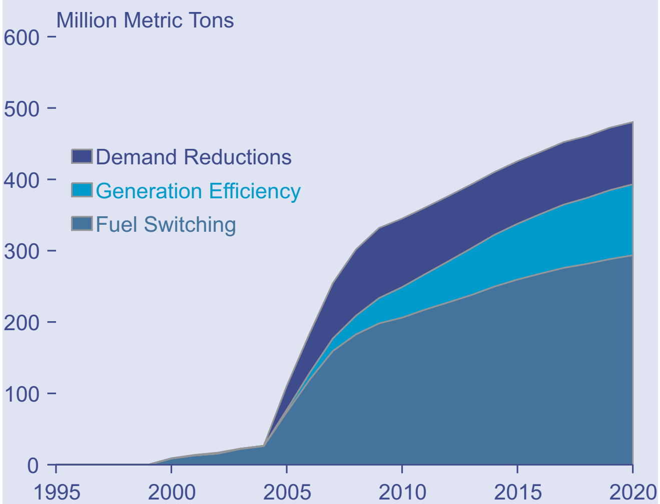
The shift away from coal-fired generation occurs because coal accounts for such a large share of power plant carbon emissions. In 1996, coal-fired power plants

**Figure 67. Projections of Carbon Emissions From the Electricity Supply Sector, 1996-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

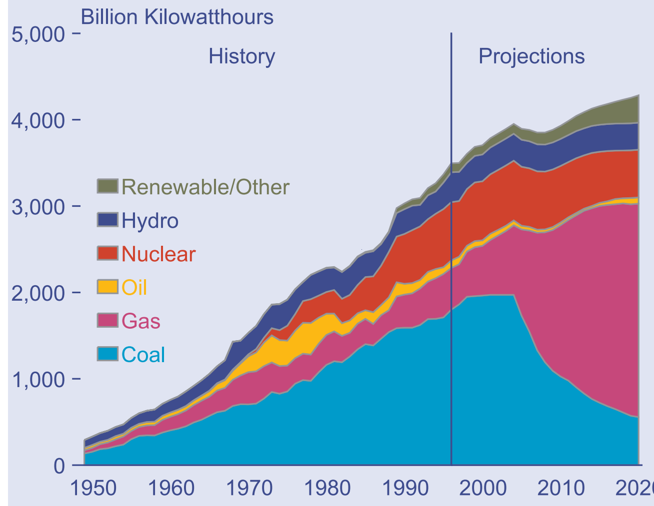
**Figure 68. Projected Reductions in Carbon Emissions From the Electricity Supply Sector, 1990-3% Case, 1996-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A and FD03BLW.D080398B.

produced an estimated 92 percent of the carbon emissions in the power generation sector. In the reference case, that share is expected to be 86 percent in 2010; and in 2020, even though natural-gas-fired generation grows rapidly, coal plants still are expected to account for 81 percent of total carbon emissions from the electricity sector. Per unit of fuel consumed (Btu), coal plants emit nearly 80 percent more carbon than do natural gas plants, and the difference is even greater per megawatthour of electricity generated (Table 17). New natural gas combined-cycle plants are much more efficient than existing coal plants, requiring less than two thirds the amount of fuel (in Btu) to produce a kilowatthour of electricity. As a result, per megawatthour of electricity

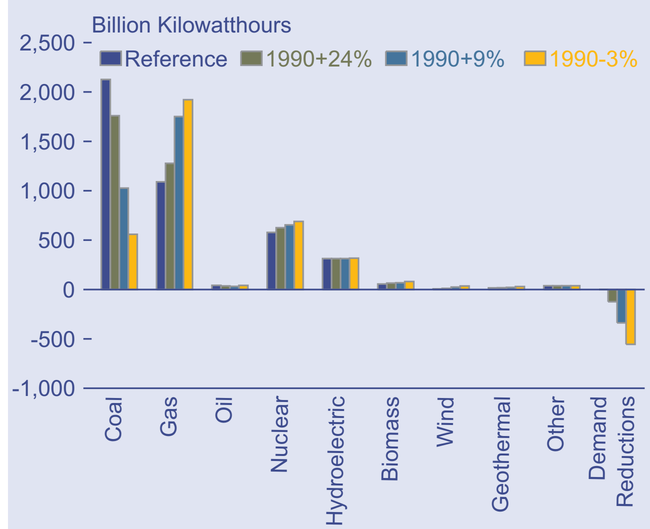
**Figure 69. Electricity Generation by Fuel, 1990+9% Case, 1949-2020**




Note: Data on nonutility generation are not available for years before 1989, but it was small. In 1989, nonutility generation accounted for 6 percent of total U.S. electricity generation.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD09ABV.D080398B.

**Figure 70. Electricity Generation by Fuel, 2010**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

produced, existing coal plants release nearly 3 times as much carbon into the atmosphere as do the most efficient new natural gas plants.

## Coal

### *Generation*

In the carbon reduction cases, the projected decreases in coal-fired electricity generation are dramatic. In the 1990+24%, 1990+9%, and 1990-3% cases, coal-fired generation in 2010 is expected to be 18 percent, 53 percent, and 75 percent lower, respectively, than in the

**Table 17. Carbon Emissions From Fossil Fuel Generating Technologies**

| Technology | Heat Rate (Btu per Kilowatthour) | Carbon Emissions | |
|---|---|---|---|
| | | Pounds per Million Btu | Pounds per Megawatthour |
| **Coal-Fired Technologies** | | | |
| Existing Capacity | 10,000 | 57 | 571 |
| New Capacity Additions | 9,087 | 57 | 519 |
| Advanced Coal Technology | 7,308 | 57 | 418 |
| **Natural-Gas-Fired Technologies** | | | |
| Conventional Turbine | 10,600 | 32 | 336 |
| Advanced Turbine | 8,000 | 32 | 253 |
| Existing Gas Steam | 10,300 | 32 | 326 |
| Conventional Combined-Cycle | 7,000 | 32 | 222 |
| Advanced Combined-Cycle | 6,350 | 32 | 201 |
| Fuel Cell | 5,361 | 32 | 170 |

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

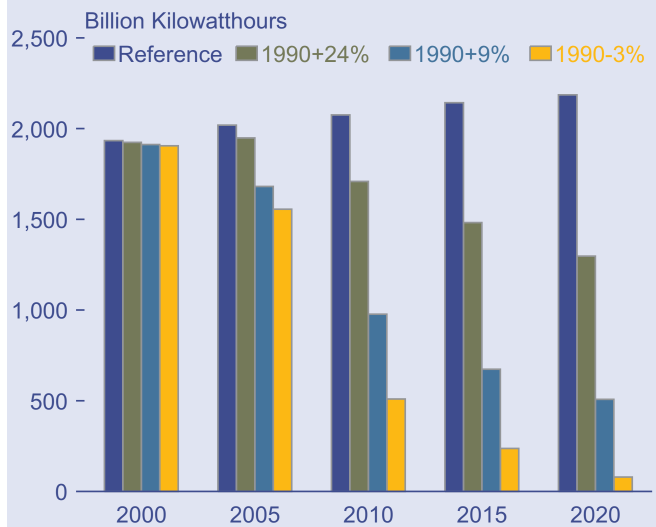
reference case (Figure 71). In 2020, the differences from the reference case are even larger: 41 percent in the 1990+24% case, 77 percent in the 1990+9% case, and over 96 percent in the 1990-3% case. In 1990-3% case, coal-fired generation is virtually eliminated. Coal plants simply are not very economical when carbon prices are high.

Such reductions in coal use would come at a cost. Although they are major carbon emitters, existing coal plants are very economical, and their operating costs have been falling (Figure 72). Under more stringent emissions reduction targets, however, with rising carbon prices, the economics of coal-fired generation would change (Table 18). For a power supplier deciding whether to continue operating an existing coal plant, build a new coal plant, build a new natural-gas-fired combined-cycle plant, or convert an existing coal-fired plant to natural gas, continued operation of the coal plant would be a clear winner in the absence of a carbon price. As the carbon price rises, however, the new natural gas plant looks more attractive. In the hypothetical example, assuming a 70-percent capacity factor for the four types of plant, it would make sense to shut the coal plant down and build a new natural gas plant at a carbon price of approximately $100 per metric ton of carbon.[55] Assuming a 30-percent capacity factor, the crossover point would be closer to $200 per metric ton of carbon. In this hypothetical example, the carbon prices that would induce power suppliers to retire existing coal plants are high, because the operating costs of most existing coal plants are low. In reality, the crossover point would vary from plant to plant.

## Generating Capacity

In all the carbon reduction cases, significant amounts of coal capacity are expected to be retired (Figure 73). In general, the projected changes in the mix of generating

**Figure 71. Projections of Coal-Fired Electricity Generation, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

capacity parallel the changes in fuel use. As the domestic carbon reduction requirement becomes more stringent, more coal capacity is retired and more natural gas and renewable plants are built (Figure 74). In the 1990+24% and 1990+9% cases, there is 3 percent and 10 percent less coal-fired capacity by 2010, and 13 percent and 36 percent less by 2020. Approximately two-thirds of the existing coal-fired capacity is projected to be retired by 2020 in the 1990-3% case. The net result is that the share of capacity accounted for by coal plants declines from around 40 percent in 1996 to just over 29 percent in 2010 and to slightly over 11 percent in 2020 in the 1990-3% case.

One possible effect of the projected coal plant retirements is that some of the plants may be shut down before their total investment costs are recovered. Such

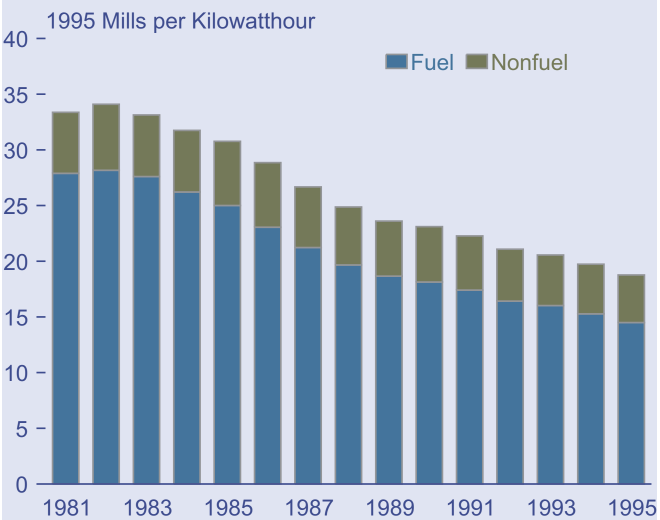
[55]In NEMS, the capacity factor for a particular plant type is determined by its operating costs. The values presented here are for illustration only.

**Table 18. Hypothetical Examples of Levelized Plant Costs at Various Carbon Prices**
(1996 Cents per Kilowatthour)

| Plant Type | Carbon Price (1996 Dollars per Metric Ton) | | | | | | |
|---|---|---|---|---|---|---|---|
| | 0 | 50 | 100 | 150 | 200 | 250 | 300 |
| **70-Percent Capacity Factor** | | | | | | | |
| Existing Coal-Fired | 1.64 | 2.92 | 4.21 | 5.49 | 6.78 | 8.06 | 9.35 |
| New Coal-Fired | 3.67 | 4.91 | 6.16 | 7.40 | 8.65 | 9.89 | 11.14 |
| New Gas-Fired Advanced Combined-Cycle | 3.04 | 3.53 | 4.02 | 4.52 | 5.01 | 5.50 | 6.00 |
| Coal-to-Gas Conversion | 3.45 | 4.19 | 4.94 | 5.68 | 6.42 | 7.16 | 7.91 |
| **30-Percent Capacity Factor** | | | | | | | |
| Existing Coal-Fired | 1.92 | 3.21 | 4.49 | 5.78 | 7.06 | 8.35 | 9.63 |
| New Coal-Fired | 6.69 | 7.93 | 9.18 | 10.42 | 11.67 | 12.91 | 14.16 |
| New Gas-Fired Advanced Combined-Cycle | 4.23 | 4.72 | 5.22 | 5.71 | 6.21 | 6.70 | 7.19 |
| Coal-to-Gas Conversion | 3.90 | 4.64 | 5.38 | 6.12 | 6.87 | 7.61 | 8.35 |

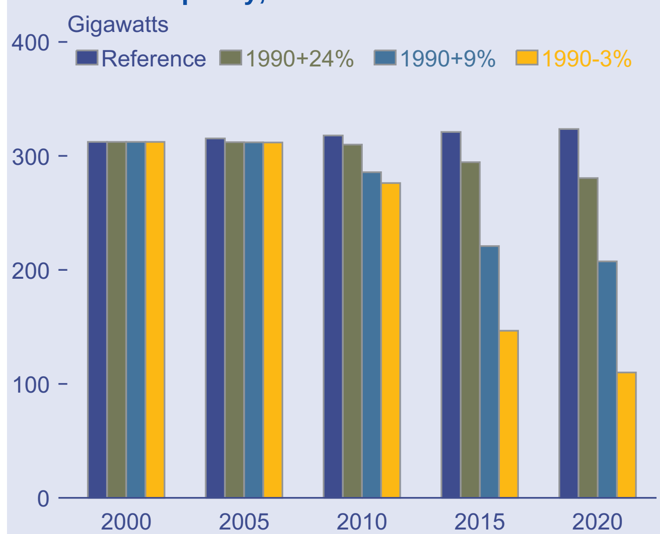
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

**Figure 72. Operating Costs for Coal-Fired Electricity Generation Plants, 1981-1995**




Source: Form FERC-1, "Annual Report of Major Electric Utilities, Licensees, and Other."

**Figure 73. Projections of Coal-Fired Generating Capacity, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

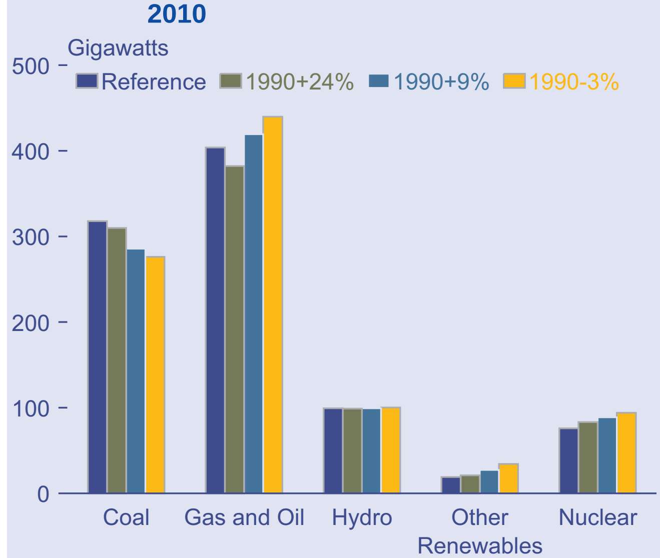
unrecovered costs would be stranded. Most coal plants are fairly old, however, and their construction costs have already been recovered. On the other hand, some plant owners could suffer losses because plants they expected to be profitable might no longer be profitable when carbon prices are imposed.

## Natural Gas

### *Generation*

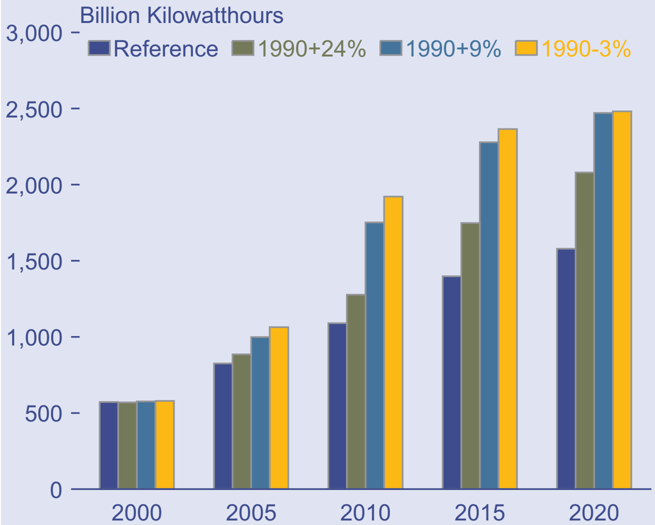
The story for natural gas generation is the opposite of that for coal (Figure 75). As the requirement to reduce carbon emissions tightens and the associated carbon price rises, natural-gas-fired generation becomes more economical than coal-fired generation. In 2010 and beyond, electricity generation from natural gas is between 17 percent and 76 percent higher in the carbon reduction cases than in the reference case projections. Overall, between 1996 and 2020, natural gas generation increases by almost 500 percent in the most stringent carbon reduction cases, and even in the 1990+24% case it

**Figure 74. Electricity Generation Capacity by Fuel, 2010**



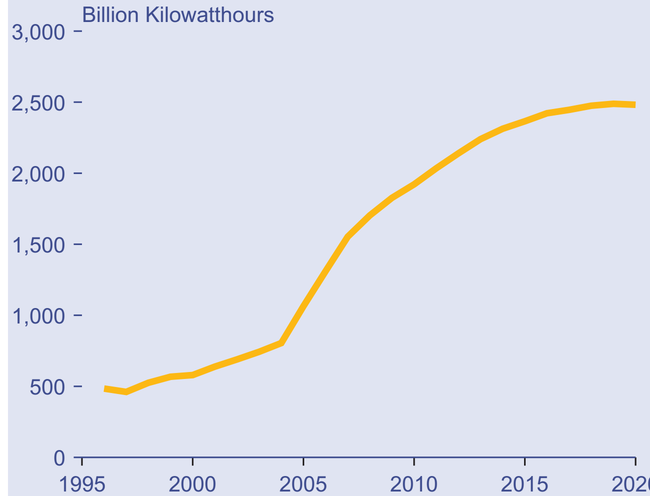

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

**Figure 75. Projections of Natural-Gas-Fired Electricity Generation, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

**Figure 76. Natural-Gas-Fired Electricity Generation, 1990-3% Case, 1996-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD03BLW.D080398B.

is more than 30 percent higher than in the reference case by 2020. Although it may be expensive to stop using low-cost coal plants, replacing them with efficient natural gas combined-cycle plants reduces carbon emissions per kilowatthour of electricity generated by nearly two-thirds.

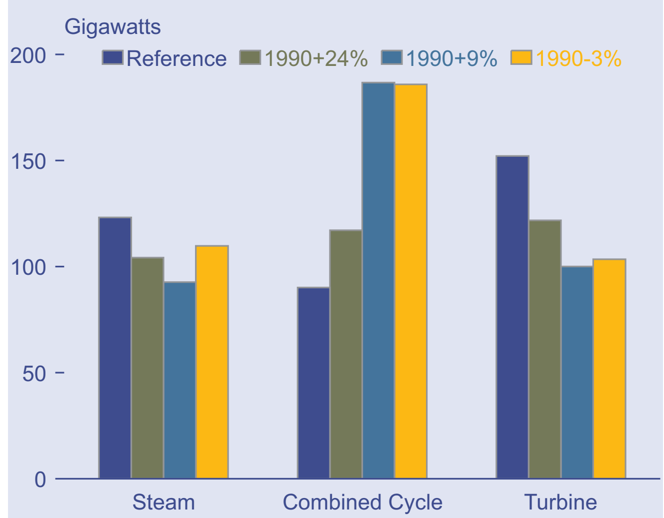
The rate of increase in natural-gas-fired generation varies over the 24-year projection period (Figure 76). When carbon emission limits are first imposed in 2005, there is rapid growth in natural gas generation, both because the rising carbon price makes existing natural gas plants more economical than existing coal plants and because new natural gas plants are added quickly. After the initial shift to natural gas, the growth in natural gas generation continues, but at a slower rate. In the later years of the projection, natural gas generation does not increase as rapidly, because carbon-free renewable technologies become economical as the demand for electricity grows and natural gas prices increase.

In the carbon reduction cases, power plant use of natural gas (excluding industrial cogeneration) is projected to rise from roughly 3 trillion cubic feet in 1996 to between 8 and 12 trillion cubic feet in 2010 and between 12 and 15 trillion cubic feet in 2020. The projected increase in demand for natural gas in the electricity sector contributes to higher gas prices overall. As a result, only small increases are projected for gas demand in other sectors for the less stringent cases. In the more stringent cases, gas demand in the other sectors (excluding industrial) actually declines. For example, in the 1990+9% case, electricity sector gas use in 2010 is 57 percent higher than projected in the reference case, but total gas consumption is only 10 percent higher (see Chapter 5 for a discussion of natural gas supply).

### *Generating Capacity*

There is only a little variation in the projections of total natural-gas-fired generating capacity across the carbon reduction cases. On the other hand, there are differences in the types of natural gas plants projected to be built (Figure 77). In the more stringent carbon reduction cases, with higher carbon prices, the mix of natural gas plants shifts from relatively inefficient simple natural gas turbines and older steam plants to more efficient combined-cycle facilities. The trend toward more efficient gas-fired technologies would be even stronger in the 1990-3% case without the significant reduction in electricity demand that is projected relative to the reference case (see below, Figure 84).

**Figure 77. Projections of Natural-Gas-Fired Electricity Generation Capacity, 2010**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

A critical question is whether new natural gas capacity can be built in sufficient quantity and in the right places to reduce carbon emissions to the levels required by the Kyoto Protocol. For example, in the 1990-3% case, the amount of capacity, mostly natural gas, projected to be built in some years far exceeds the amount of capacity built in any year since 1983. The average amount of generating capacity brought on line each year since 1983 has been around 10 gigawatts (33 typical plants).[56] The peak year was 1985, when just under 22 gigawatts of capacity was added. In the 1990-3% case, annual additions are projected to exceed 28 gigawatts (93 typical plants) in some years.

Some gas-fired plants are expected to be built to meet growth in demand, but most are likely to replace retiring coal plants. From 2008 to 2020, the projected additions of generating capacity in the 1990-3% case average 24 gigawatts annually, with just over 28 gigawatts in 2009. This level of construction is high but not unprecedented. It is actually less than the amount of capacity that was built annually during the 1970s, when the demand for electricity was growing at more than twice the rate projected in the reference case.

Given time and forewarning, the natural gas plant design and construction industry should be able to meet the challenge presented in the carbon reduction cases; however, the prices for new gas-fired facilities might rise above those used in this analysis. In addition, the situation could be exacerbated by the fact that many other countries may also be turning to natural gas in order to reduce their carbon emissions.

Not only will a large number of new natural gas plants have to be built, they will also have to be built in the right places. Today's electricity transmission system is constructed around major load and supply centers, connecting major cities to major power plants. The location of power plants is critical to the reliability of the electricity supply system. If, as expected, a large number of existing coal plants are retired to reduce carbon emissions, many of the new gas plants will have to be built at the locations of the coal plants they replace, in order to maintain the reliability of the system. (Biomass and wind plants must be built where their resources are available.) The alternative would be to reconfigure the transmission system to accommodate new plant locations,[57] an undertaking that might require additional investment.

One option for adding new natural-gas-fired capacity would be to modify existing coal-fired plants to burn natural gas instead of coal. This option, however, may not prove to be economical. Generally, there are two approaches for converting a coal plant to burn gas. The first is simply to modify the existing coal boiler so that it can be fired with natural gas. From a mechanical perspective this is not terribly difficult or expensive. The required plant modifications would be expected to cost $70 to $80 per kilowatt of capacity, mainly for new burners and gas handling equipment (compressors, metering station, distribution headers, etc.). In terms of performance, there would be a small loss of efficiency, 2 to 5 percent, if gas were burned in a boiler originally designed to burn coal.[58]

The main problem with this approach to plant conversion is the relative thermal inefficiency of existing coal plants. The majority of older coal plants consume between 10,000 and 10,500 Btu of fuel for each kilowatthour of electricity they produce,[59] as compared with 6,500 to 7,500 Btu of fuel input for each kilowatthour of electricity produced by a new gas-fired combined-cycle plant. Existing coal plants are economical because the fuel is inexpensive, not because they are thermally efficient.

As described above (see Table 18), in the absence of required carbon emissions reductions, existing coal-fired plants are the most economical option for electricity generation. Conversion of existing plants from coal to gas is not the most economical option if the plant is to be used at a high capacity factor. If the price of carbon emissions rises, however, continuing to run the existing coal plant becomes less economical. Assuming a 70-percent capacity factor and a carbon price of $100 per metric ton, it would make sense to abandon the plant (not the site) and build a new gas-fired combined-cycle plant. At a lower capacity factor, the carbon price would have to be higher before the operational cost savings from the greater efficiency of a new combined-cycle plant would offset its higher capital costs (Table 18).

The second approach to using gas in an existing coal plant would be to "repower" it by converting it into a natural gas combined-cycle plant. This approach would result in higher plant efficiency, but it would also be much more expensive than the first approach. In a typical repowering, the coal handling system and the boiler are replaced with new combustion turbines and a heat

[56]Depending on the technology type, new power plants differ tremendously in size, from a few kilowatts for the smallest distributed photovoltaic technologies to 500,000 kilowatts (500 megawatts) or more for the largest new coal and nuclear technologies. Throughout this report, when a number of typical plants is provided, a 300-megawatt average plant size is used.

[57]See Energy Information Administration, "An Exploration of Network Modeling: The Case of NEPOOL," in *Issues in Midterm Analysis and Forecasting 1998*, DOE/EIA-0607(98) (Washington, DC, July 1998), for a discussion of the impact of plant location on reliability and pricing.

[58]Cost and performance impact estimates provided by Parsons Engineering.

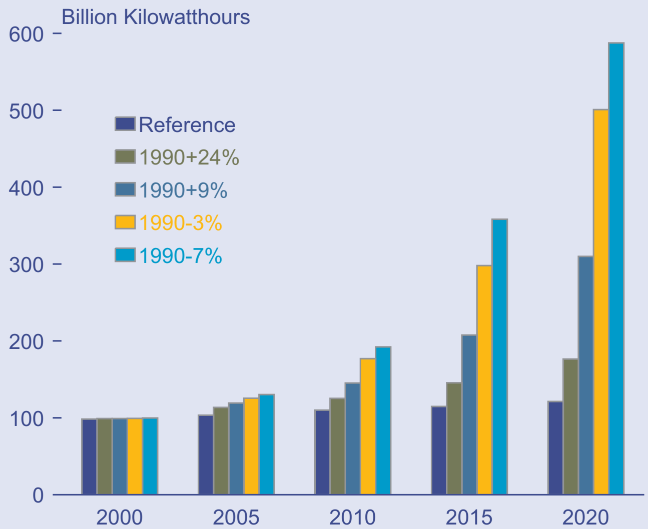
[59]Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

recovery boiler. The only significant part of the plant that is maintained is the original turbine generator. This approach can be attractive at some facilities, but it is not without problems. New combined-cycle plants are packaged systems. The turbines, heat recovery boiler, and turbine generator are designed to work smoothly together for optimal efficiency. Because many older coal-fired plants were custom designed and built, they do not always come in standard sizes or configurations or with standard operational parameters. If such facilities are to be repowered, additional work will be required to integrate the system components. Given that for a typical combined-cycle plant the steam turbine generator accounts for between 10 and 22 percent of the capital cost of the plant,[60] the additional work could easily drive the cost of repowering beyond what it would cost simply to replace the plant with a new, more efficient packaged combined-cycle plant.

## Renewable Fuels

In the carbon reduction cases, U.S. electricity suppliers are expected to turn to renewable energy resources later in the projection period to meet the demand for electricity while reducing carbon emissions. Wind, biomass, geothermal, solar, and hydropower resources generally are thought to have less environmental impact than fossil fuels; they are domestically available; and in some instances they have begun to penetrate U.S. electricity markets. Significant growth in the use of nonhydroelectric renewable resources for electricity generation is expected to accompany efforts to reduce carbon emissions (Figure 78).

**Figure 78. Projections of Nonhydroelectric Renewable Electricity Generation, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

The largest increases in renewable generation are expected after 2010 in the most stringent carbon reduction cases (Table 19). For this reason, the results of the 7-percent-below-1990 (1990-7%) case are also discussed in this section. Before 2010, nonhydroelectric renewable technologies generally are not competitive with new natural gas plants, but their costs are expected to fall over time. With higher carbon prices, these technologies can be expected to play a significant role in reducing carbon emissions. In the reference case little growth in generation from renewables is expected. In the carbon reduction cases, nonhydroelectric renewable generation is 1.1 to 1.7 times the reference case level in 2010 and 1.5 to 4.8 times the reference case level in 2020.

Because of the lack of market experience with renewable technologies other than hydropower, there is considerable uncertainty about the costs of developing them on the scale that would be needed for large carbon emission reductions. It is also unclear whether electric system reliability can be maintained if large quantities of wind or solar, which have intermittent output, are developed. Although some environmental objections have been raised against some renewables, including negative effects on animal life, destruction of habitat, and damage to scenery and recreation, these effects are small in comparison with the alternatives. While wind and biomass technologies are expected to be the most important renewable technologies used to reduce carbon emissions, others—including geothermal, conventional hydroelectric, and solar power plants—may also play a role (Table 19).

### *Wind*

Among the nonhydroelectric renewable fuels, biomass and wind technologies are expected to make the most significant contributions to carbon emission reductions. Projected growth in the wind and biomass industries, together with the natural gas industry, would at least partially offset the impacts of declines in the coal industry. The biomass industry in the United States today is small, but it could see large growth. Similarly, the wind industry, estimated to employ 30,000 to 35,000 people worldwide in 1995, could increase several times over in the most stringent carbon reduction cases. In some regions, wind is projected to provide a significant share of electricity supply. However, the ability of wind resources to meet large-scale U.S. electric power needs reliably and cost-effectively is uncertain. Wind power is an intermittent technology, available only part of the time during a day or season. As a result, EIA assumes that the maximum contribution of wind power will be limited to 12 percent of any region's total annual generation requirements (excluding cogeneration) to avoid reliability problems that larger shares might cause.

[60] Electric Power Research Institute, *Technical Assessment Guide*. The steam turbine and auxiliary systems account for 10 percent of the plant. If the boiler can also be used, this figure rises to 22 percent.

**Table 19. Projected U.S. Electricity Generation From Renewable Fuels**
(Billion Kilowatthours)

| | 2000 | 2010 | | | | | 2020 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Projection | Reference | Reference | 1990 +24% | 1990 +9% | 1990 -3% | 1990 -7% | Reference | 1990 +24% | 1990 +9% | 1990 -3% | 1990 -7% |
| **Electricity Generators** | | | | | | | | | | | |
| Conventional Hydropower | 310.3 | 313.0 | 313.0 | 313.0 | 317.4 | 321.9 | 313.2 | 313.1 | 313.1 | 317.7 | 322.4 |
| Geothermal | 17.2 | 16.8 | 18.0 | 21.7 | 29.9 | 30.4 | 19.9 | 25.1 | 33.4 | 47.2 | 53.3 |
| Municipal Solid Waste | 22.8 | 27.0 | 27.0 | 26.8 | 26.5 | 26.5 | 29.8 | 29.8 | 29.7 | 29.8 | 29.9 |
| Wood and Other Biomass | 8.2 | 8.7 | 17.6 | 21.0 | 34.7 | 36.4 | 8.7 | 22.5 | 83.1 | 244.4 | 305.1 |
| Solar Thermal | 0.9 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.5 | 1.5 | 1.5 | 1.5 | 1.5 |
| Solar Photovoltaic | 0.1 | 0.6 | 0.6 | 0.6 | 0.7 | 1.0 | 1.4 | 1.4 | 1.4 | 1.8 | 2.3 |
| Wind | 5.7 | 6.2 | 11.2 | 24.7 | 35.7 | 48.9 | 8.7 | 43.6 | 108.3 | 123.4 | 142.8 |
| **Subtotal** | **365.2** | **373.5** | **388.6** | **409.0** | **446.1** | **466.2** | **383.2** | **437.0** | **570.5** | **765.9** | **857.2** |
| **Cogenerators** | | | | | | | | | | | |
| Municipal Solid Waste | 2.2 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 | 2.3 |
| Biomass | 41.2 | 47.3 | 47.4 | 46.9 | 45.9 | 45.6 | 48.9 | 50.2 | 50.2 | 50.4 | 50.5 |
| **Subtotal** | **43.5** | **49.6** | **49.7** | **49.2** | **48.2** | **47.9** | **51.2** | **52.5** | **52.5** | **52.7** | **52.8** |
| **Total Renewable Generation** | **408.7** | **423.1** | **438.3** | **458.2** | **494.3** | **514.1** | **434.4** | **489.5** | **623.1** | **818.5** | **910.0** |
| **Total Electricity Generation** | **3,716.8** | **4,267.6** | **4,144.0** | **3,929.7** | **3,712.6** | **3,641.7** | **4,648.2** | **4,422.3** | **4,282.7** | **4,160.2** | **4,105.1** |
| Renewable Share of Generation (Percent) | 11.0 | 9.9 | 10.6 | 11.7 | 13.3 | 14.1 | 9.3 | 11.1 | 14.5 | 19.7 | 22.2 |
| Nonhydroelectric Renewable Share of Generation (Percent) | 2.6 | 2.6 | 3.0 | 3.7 | 4.8 | 5.3 | 2.6 | 4.0 | 7.2 | 12.0 | 14.3 |

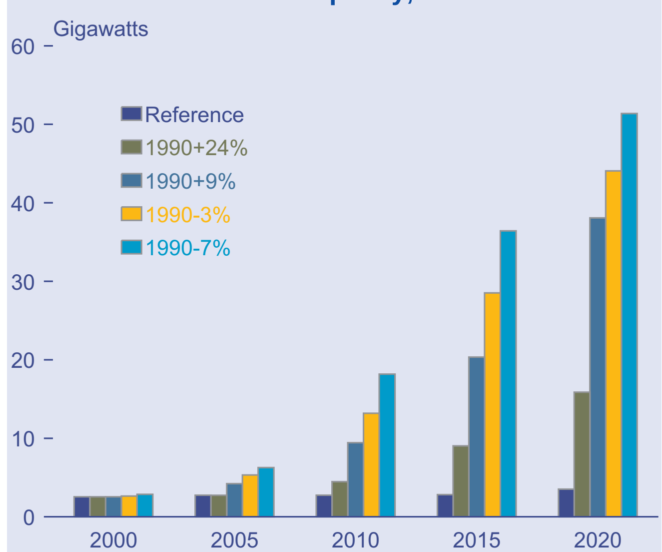
Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

In the reference case, wind remains a minor contributor to both total renewable energy and total electricity supply through 2020 (Table 19), accounting for just 2 percent of generation from renewables and far less than 1 percent of total generation. In the carbon reduction cases, its contribution grows. In the 1990+9% case, generation from wind resources reaches 25 billion kilowatthours in 2010 and 108 billion kilowatthours in 2020, accounting for nearly 17 percent of renewable generation and 2.5 percent of all U.S. electric power. In the 1990-3% and 1990-7% cases, with greater carbon reduction requirements, U.S. reliance on wind power is expected to be higher, particularly after 2010. Generation from wind power reaches 36 billion kilowatthours by 2010 in the 1990-3% case and increases even more thereafter, reaching 123 billion kilowatthours in 2020. In the 1990-7% case it rises to 10 percent of renewable generation in 2010 and 16 percent (143 billion kilowatthours) in 2020, accounting for more than 3 percent of all electric power output.

In terms of generating capacity, wind accounts for more than 11 percent of all renewables capacity in 2010 in the 1990-3% case and 26 percent of all renewables capacity in 2020 in the 1990-7% case (Table 20). Again, however, wind-powered capacity remains a relatively small share of overall U.S. electricity generating capacity, in no case exceeding 6 percent of the total. Wind power is already entering some U.S. markets, and hundreds of megawatts of new wind capacity is expected to enter U.S. service before 2000. In the carbon reduction cases, wind power expands rapidly (Figure 79). The projection for wind capacity in 2005 in the 1990+9% case exceeds the reference case projection for 2020, and in 2020 it is more than 38 gigawatts. The wind capacity projections for 2020 are 44 gigawatts in the 1990-3% case and 51 gigawatts in the 1990-7% case—more than 14 times the reference case forecast.

The importance of wind power varies from region to region. Whereas wind capacity today is concentrated in

**Figure 79. Projections of Wind-Powered Electricity Generation Capacity, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

**Table 20. Projected U.S. Electricity Generation Capacity From Renewable Fuels**
(Gigawatts)

| Projection | 2000 Reference | 2010 Reference | 2010 1990 +24% | 2010 1990 +9% | 2010 1990 -3% | 2010 1990 -7% | 2020 Reference | 2020 1990 +24% | 2020 1990 +9% | 2020 1990 -3% | 2020 1990 -7% |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Electricity Generators** | | | | | | | | | | | |
| Conventional Hydropower | 79.39 | 79.78 | 79.78 | 79.80 | 80.74 | 81.84 | 79.78 | 79.79 | 79.80 | 80.78 | 81.92 |
| Geothermal | 3.02 | 2.80 | 2.98 | 3.51 | 4.68 | 4.75 | 3.02 | 3.77 | 4.95 | 6.94 | 7.81 |
| Municipal Solid Waste | 3.40 | 4.02 | 4.01 | 3.99 | 3.95 | 3.95 | 4.42 | 4.42 | 4.41 | 4.43 | 4.44 |
| Wood and Other Biomass | 1.64 | 1.76 | 1.80 | 2.70 | 4.93 | 5.32 | 1.76 | 2.74 | 11.95 | 35.27 | 43.99 |
| Solar Thermal | 0.36 | 0.44 | 0.44 | 0.44 | 0.44 | 0.44 | 0.54 | 0.54 | 0.54 | 0.54 | 0.54 |
| Solar Photovoltaic | 0.02 | 0.22 | 0.22 | 0.22 | 0.27 | 0.39 | 0.56 | 0.56 | 0.56 | 0.71 | 0.91 |
| Wind | 2.55 | 2.75 | 4.47 | 9.44 | 13.19 | 18.17 | 3.52 | 15.87 | 38.08 | 44.06 | 51.37 |
| **Subtotal** | **90.39** | **91.77** | **93.71** | **100.10** | **108.20** | **114.85** | **93.60** | **107.68** | **140.29** | **172.72** | **190.97** |
| **Cogenerators** | | | | | | | | | | | |
| Municipal Solid Waste | 0.44 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 | 0.45 |
| Biomass | 6.08 | 6.70 | 6.68 | 6.60 | 6.48 | 6.44 | 6.84 | 6.96 | 6.93 | 6.93 | 6.94 |
| **Subtotal** | **6.52** | **7.14** | **7.13** | **7.05** | **6.92** | **6.89** | **7.29** | **7.41** | **7.38** | **7.38** | **7.39** |
| **Total Renewable Capacity** | **97** | **99** | **101** | **107** | **115** | **122** | **101** | **115** | **148** | **180** | **198** |
| **Total Electricity Capacity** | **803** | **916** | **895** | **921** | **945** | **944** | **1,008** | **972** | **965** | **958** | **949** |
| Renewable Share of Capacity (Percent) | 12.07 | 10.80 | 11.26 | 11.64 | 12.19 | 12.90 | 10.01 | 11.84 | 15.30 | 18.79 | 20.91 |
| Nonhydroelectric Renewable Share of Capacity (Percent) | 2.18 | 2.09 | 2.35 | 2.97 | 3.64 | 4.23 | 2.09 | 3.63 | 7.03 | 10.36 | 12.27 |

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

a few places—principally California, with smaller amounts in Texas and Minnesota—in the carbon reduction cases, wind power development is expected to occur in most regions west of the Mississippi River, as well as in New England. Wind plants do not penetrate heavily in most parts of the East and Southeast, where resources are limited. For example, in the 1990-3% case, more than 70 percent of all wind capacity in 2010 is projected to be in the West, with three-quarters of the remainder in the Upper Midwest. Still, wind power supplies only around 2 percent of generation in the Upper Midwest, the Northwest and California and nearly 10 percent in the Southwest in 2010 in the 1990-3% case. On the other hand, in the 1990-7% case, wind accounts for significant shares of total generation in 2020 in some regions.

Large-scale wind power development faces significant uncertainties with regard to reliability, technology costs, and resource development costs. Concerns about reliability center around the intermittent nature of wind. In some areas, winds are highly predictable and coincident with daily or seasonal electric power demands. By nature, however, winds are rarely steady, are in various degrees unpredictable (intermittent), and may occur at times of low demand. As a result, wind power requires the availability of other capacity to back it up. In addition, the variation in output from wind plants can stress distribution and transmission lines as well as other generating equipment. The upper limit on the amount of wind capacity that can be handled economically on a given system is unknown. Various studies suggest a very wide range of possibilities, but the highest value achieved for a single hour in the United States is 8 percent.

In Europe, wind power development has grown rapidly in recent years. In 1997, for example, Germany surpassed the United States in total wind capacity and became the first nation to exceed 2,000 megawatts of capacity. In Denmark, wind capacity exceeded 1,100 megawatts in 1997 and could approach 10 percent of the nation's electricity generation by 2005 if planned expansion occurs. In Spain total wind capacity exceeded 450 megawatts at the end of 1997. In all three nations, additional wind capacity additions are planned over the next 5 years.

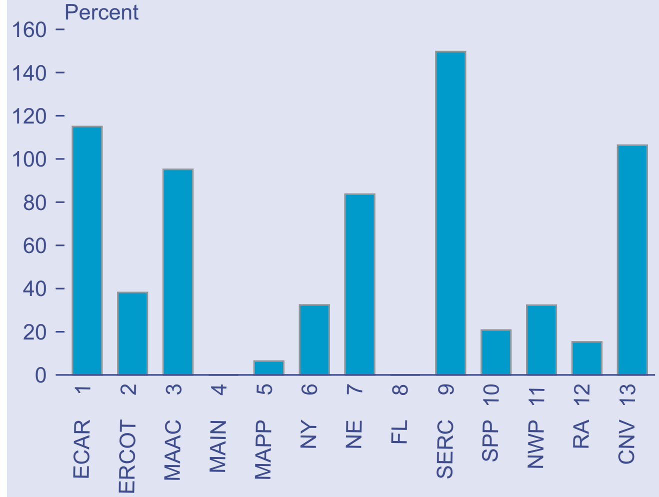
The rapid wind development in Europe is being encouraged by relatively high electricity prices and government subsidies. Under German law, wind power producers are reportedly paid the equivalent of 9 to 10 cents per kilowatthour (90 percent of the residential retail price). Prices paid to wind developers are reported to be up to 9 cents per kilowatthour in Denmark and about 8 cents per kilowatthour in Spain. Those prices are much higher than U.S. wholesale electricity prices, which typically are 2 to 4 cents per kilowatthour. Nevertheless, the European record suggests that power systems can support a larger share of wind than they have in the United States to date and that, if prices are high enough, capacity can be added fairly rapidly.[61]

A second issue is the considerable uncertainty surrounding the future cost of wind turbines. Installed capital costs for wind turbines and associated equipment have fallen over the past 20 years and are expected to continue falling, particularly if large numbers of turbines are built. The costs are near $1,000 per kilowatt of wind capacity today, and they are projected to be below $800 per kilowatt early in the 21st century and to approach $600 per kilowatt by 2020 in the most stringent carbon reduction cases. With no known manufacturing barriers to large increases in factory production capacity for wind turbines, the industry should be able to meet the production levels called for in the carbon reduction cases, given sufficient lead times. Of course, it is impossible to say with certainty that the projected cost declines will occur. This analysis does adjust for the cost effects of short-term bottlenecks in identifying sites, permitting projects, manufacturing equipment, and installing projects, but the actual effects of rapid large-scale expansion are not known.

While there appear to be large wind resources in many regions, the costs of developing some of the sites may be high. In general, wind power costs are expected to increase as the best natural resources are consumed and less-favored sites enter service. Lower quality sites—including those on steep, rocky, or sharply varied surfaces, those in more difficult environments (excessive cold, moisture, dirt, insects, or storms), and those with less useful winds (unpredictable, ill-timed, sharply varying, too fast)—could have much higher costs than more favorable sites. Moreover, in most regions only a portion of the total potential is likely to be economical. The possible stress on wind resources (and therefore costs) can be seen by comparing projections of wind capacity with EIA's estimates of "economic" resources—identified as those available at capital costs no more than double the baseline projection (Figure 80). In the 1990-7% case, eight regions consume a third or more of "economic" wind resources, and three regions exceed that portion of supply, including California. In those regions, more expensive wind resources are developed in the most stringent carbon reduction cases. Little is known about the actual costs at these levels of resource use.[62]

The costs of transmission interconnections and of upgrading existing distribution and transmission networks are also expected to increase as the penetration of wind resources grows. As projects are developed at greater distances from existing lines, the costs of new interconnections will increase. In addition, the costs of upgrading existing local distribution networks, both to transmit the electricity generated from wind power and to offset the destabilizing local effects of varying power flows, will increase.

**Figure 80. Projected Shares of Most Economical Wind Resources Developed by Region, 1990-7% Case, 1996-2020**




Note: ECAR = East Central Area Reliability Coordination Agreement Region; ERCOT = Electric Reliability Council of Texas; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP = Mid-Continent Area Power Pool; NY = New York Power Pool; NE = New England Power Pool; FL = Florida subregion of the Southeastern Electric Reliability Council; STV = Southeastern Electric Reliability Council excluding Florida; SPP = Southwest Power Pool; NWP = Northwest Pool subregion of the Western Systems Coordinating Council; RA = Rocky Mountain and Arizona-New Mexico Power Areas; CNV = California-Southern Nevada Power Area.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System run FD07BLW.D080398B.

Finally, market competition for land with good wind resources is also likely to increase the future costs of extensive wind power development. Other urban or agricultural uses may compete for some locations. Public opposition to wind project development on environmental, cultural, and recreational grounds may also grow as large numbers of wind facilities are built. Because excellent wind resources tend to occur in highly visible places, such as along ridges and other natural projections, preferred sites often serve other cultural, scenic, or religious purposes, and they may not be made available for wind power development. For example, it remains to be seen whether the development of 170 square miles in Texas (about 0.1 percent of the land area) for the wind capacity that would be needed to meet the 2020 projections in the 1990-7% case would be acceptable to the State's inhabitants.

[61] American Wind Energy Association, *International Wind Energy Capacity Projections* (Washington, DC, April 1998).

[62] Only 6 percent of the estimated wind resources in region 5 (including Minnesota, Iowa, and the Dakotas) are used in the 1990-7% case; however, the remaining resources are not economically accessible to other regions.

## *Biomass*

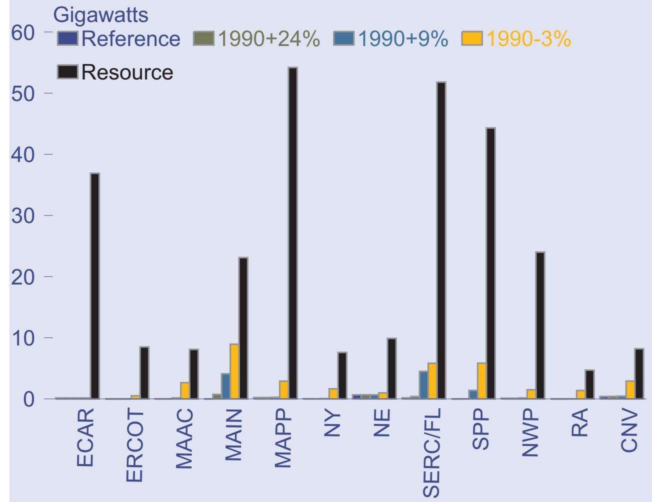
Unlike wind plants, which are intermittent, biomass plants operate continuously. Biomass currently is being used to supply energy for power generation and in the industrial, transportation, and residential sectors. The largest amount of biomass is used in the paper and lumber industries, where residue is burned to produce both electricity and steam (cogeneration). Biomass is also used to produce ethanol for fuel in the transportation sector, and wood is burned for residential heating.

Current biomass consumption in the electricity sector, excluding cogeneration, is limited to a few inefficient wood-burning generating units and a small amount of cofiring at coal plants. Newer technologies, primarily several types of gasification combined-cycle units, are in the demonstration phase in the United States and are expected to be commercially available by 2005. Such units would be somewhat more expensive than current technology, but they are expected to be more than twice as efficient. They can use a variety of fuel sources, such as wood and wood residues, several types of energy crops, and crop residues. Without a carbon price, these facilities currently are not competitive with new natural gas or coal plants. However, using biomass in the production of electricity produces no net carbon emissions. The carbon emitted during biomass combustion approximates the carbon sequestered during the growth of the trees or crops that are burned. As a result, it is an attractive option for complying with the Kyoto Protocol.

In the 1990+24% case, biomass generation increases only slightly from the levels projected in the reference case. In the 1990+9% case, however, biomass generation is projected to reach 68 billion kilowatthours—21 percent above the reference case projection—in 2010 and 133 billion kilowatthours—more than double the reference case projection—in 2020. In the 1990-3% case, biomass generation is projected to be 81 billion kilowatthours in 2010—44 percent above the reference case—and 295 billion kilowatthours—5.0 times the reference case—in 2020. And in the 1990-7% case, biomass generation exceeds the reference case projection by about 47 percent in 2010 and by 6.2 times in 2020. In each of these cases, biomass is allowed to contribute up to 5 percent of a coal plant's fuel input, but because coal plant usage declines rapidly as the carbon price increases, the contribution from cofiring is limited.

With biomass resources projected to play such a major role in meeting electricity needs in the carbon reduction cases, a critical question is whether the projected levels of reliance on biomass would be realistic. To answer that question, it is necessary to examine the components of the biomass resource. Biomass resources are diverse and potentially much larger than the amounts projected to be developed even in the most stringent carbon reduction cases in this analysis (Figure 81).

**Figure 81. Estimated Biomass Resource Availability and Projected Generating Capacity in 2020 by Region**




Note: ECAR = East Central Area Reliability Coordination Agreement Region; ERCOT = Electric Reliability Council of Texas; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP = Mid-Continent Area Power Pool; NY = New York Power Pool; NE = New England Power Pool; FL = Florida subregion of the Southeastern Electric Reliability Council; STV = Southeastern Electric Reliability Council excluding Florida; SPP = Southwest Power Pool; NWP = Northwest Pool subregion of the Western Systems Coordinating Council; RA = Rocky Mountain and Arizona-New Mexico Power Areas; CNV = California-Southern Nevada Power Area.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Biomass materials are derived from a variety of sources, including urban wood waste, mill residues, forest residue, agricultural residue, and energy crops grown specifically for combustion. Urban wood waste includes tree trimmings, construction and demolition debris, and discards such as crates and pallets. (Some of these materials are currently being used to make recycled products or as fuel, and the resource data used for this analysis exclude those quantities.) Mill residues are the sawdust and scrap from sawmills, pulp mills, and wood product facilities. Many mill residues are consumed on site, but some are accumulated in stockpiles or sent to landfills, often at a cost to the producer. Forest residues are, generally, material that is too low grade to be used for other products. They include branches, dead trees, unmarketable species, and cull trees from commercial forests. The alternative to its use as a fuel is to leave it in the forest. Agricultural residues include a wide variety of materials. The greatest quantities (and the only amounts included in this analysis) are from wheat straw and cornstalks. Only a small amount is currently used as fuel, most being left in the field. It is assumed here that only 40 percent of all agricultural residues would be available for use as fuel, with the rest continuing to be left in the field. What the above types of residues have in common is that they are very inexpensive at the source. On the other hand, the cost of gathering and delivering them to a power plant, compared with the cost of coal, usually makes them too expensive for use in electricity generation under current economic conditions.

Energy crops involve dedicated operations that would likely require long-term agreements between growers and conversion plant operators. The primary energy crops are willow, poplar, and switchgrass, each with distinct growing areas and conditions. Energy crops differ from residues in that it is the cost of growing them, not collection, that dominates their total costs.

Agricultural lands can be divided into croplands, pasturelands, and Conservation Reserve Program (CRP) acreage. The total U.S. agricultural land supply is approximately 960 million acres, of which about one-third is now used for field crops. In some instances, energy crops can be grown on poor quality land that has no other use. The amounts of agricultural land assumed to be available for energy crops in the resource data used for this analysis include all the CRP acreage, 20 percent of the cropland, and 10 percent of the pastureland. However, even in the cases that project the highest levels of biomass use, the total amount of land needed for energy crops would be about 10 to 12 million acres, which is in the range of the yearly fluctuations of U.S. cropland planted. Thus, the question of competition for land does not appear large. As fossil fuel prices rise in the more stringent carbon reduction cases, the value of biomass fuels would also rise, making energy crops more attractive economically.

There may be competition between the use of land for biomass energy crops and its use for tree planting to increase carbon sequestration. In terms of the amount of carbon sequestered or emissions avoided per acre of land used, displacing a new gas-fired plant with a biomass-fired plant would have about the same impact as planting trees. For example, the U.S. Environmental Protection Agency estimates that planting 1 acre of trees on marginal land would sequester 0.6 to 1.6 metric tons of carbon annually.[63] In comparison, if a new biomass power plant displaced a new gas-fired plant, an estimated 1.3 metric tons of carbon emissions would be avoided per acre of land used.[64] The comparison would not be as close if the generation displaced were from a coal-fired power plant, which would emit roughly 3 metric tons of carbon in producing the same amount of electricity that a biomass plant would generate from 1 acre of crops. The critical issue in the land use decision between tree planting and energy crops will be the relative economics of the two choices. If sequestration proves to be more economical, fewer biomass plants may be built than projected in this analysis. Instead of building a biomass plant, a developer could simply build a gas-fired plant and also grow enough trees to offset the carbon emissions from the plant.

It is assumed in this analysis that energy crops will not become economical until new integrated gasification combined-cycle (IGCC) plants are available in 2005 and after. The current technology for biomass plants, using stoker boilers, is inefficient and uneconomical. The newer IGCC technology is now being tested, and it is expected to be vastly superior to the current technology in terms of both efficiency and emissions. Most of the experience with the IGCC technology has been in Europe, particularly in Scandinavia. Sydkraft, the second-largest utility in Sweden, has been operating a 6-megawatt wood-fired IGCC plant in Varnami, Sweden, since 1994. Finland has a 30-megawatt unit operating on wood waste, as well as several smaller peat-fired gasification units with a combined capacity of 50 megawatts. There are several other demonstration plants that total about 5 megawatts of capacity worldwide. Future plans include 12 megawatts of capacity in Italy (Bioelettrica), 8 megawatts in the United Kingdom, and 32 megawatts in Brazil. In addition, a number of refineries are currently operating IGCC plants that burn petroleum coke.

In the United States, the most advanced IGCC project is operated by the Vermont Department of Public Works in cooperation with utilities in the State, the U.S. Department of Energy, the U.S. Environmental Protection Agency, and the U.S. Agency for International Development. The system, which gasifies waste wood and wood chips from a dedicated poplar tree farm, is just beginning operation, with a design capacity of 15 megawatts. The project is being used to demonstrate the economics of the technology. In addition, a privately owned 7.5-megawatt unit fueled with various wood, paper, and industrial wastes began operating in the Midwest in June 1998, and a 75-megawatt alfalfa-fired unit is planned for operation in 2001 in Minnesota.

As shown in Table 21, the potential resource base for biomass from all sources amounts to approximately 15 quadrillion Btu annually, roughly enough to meet 15 percent of today's U.S. energy needs if fully developed. Even in the most stringent carbon reduction case, however, only about 15 percent of the resource, about 2.3 quadrillion Btu, is projected to be used. The region that shows the greatest projected growth in biomass consumption is the Southeast, followed by the Midwest. The Southeast has ample supplies of both forests and cropland. In the Midwest, the land suitable for energy crops is vast, although energy demand there is low. The

[63]U.S. Environmental Protection Agency, *Climate Change Mitigation Strategies in the Forest and Agriculture Sectors* (Washington, DC, June 1995), p. ES-5.

[64]This estimate was derived from the following assumptions: biomass yield 6 tons per acre, biomass heat content 17,000,000 Btu per ton, biomass plant heat rate 8,000 Btu per kilowatthour, gas plant heat rate 7,000 Btu per kilowatthour, and natural gas carbon content 14,400 metric tons per trillion Btu.

region that comes closest to reaching a limit on available resources is Florida, which has high electricity demand and limited biomass resources. The West is the area that uses biomass the least, because land suitable for energy crops is limited, and other resources, including other renewables, are more plentiful.

**Table 21. U.S. Biomass Resources**

| Biomass Resource | Quantity Available in 2020 (Quadrillion Btu) | Price Range (1996 Dollars per Million Btu) |
|---|---|---|
| Urban Wood Waste . . . | 0.2 | 0 - 3 |
| Mill Residues . . . . . . . . | 0.8 | 1 - 4 |
| Forest Residues. . . . . . | 6.5 | 3 - 4 |
| Crop Residues . . . . . . . | 0.9 | 2 - 3 |
| Energy Crops. . . . . . . . | 6.5 | 1 - 3 |
| **Total** . . . . . . . . . . . . . | **15.0** | — |

Source: **Urban Wood Waste and Mill Residues:** Antares Group, Inc. **Forest and Crop Residues:** Oak Ridge National Laboratory. **Energy Crops:** Oak Ridge Energy Crop County Level Database (December 20, 1996).

**Biomass Limitation.** Because of concerns about the ability of the biomass energy business to develop as rapidly as would be required to meet the capacity and generation projections in the most stringent carbon reduction cases in this analysis, a special sensitivity case was analyzed, assuming that no new biomass capacity would be built. All other assumptions were same as those in the 1990-7% carbon reduction case. In the sensitivity case, the projected carbon price was approximately $39 per metric ton higher in 2020 than in the 1990-7% case, with smaller increments in 2010 and 2015.

Without additional biomass capacity, new natural gas capacity for electricity generation was projected to be about 43 gigawatts higher than in the 1990-7% case in 2020, making up 212 billion kilowatthours of the 295 billion kilowatthours of generation "lost" from biomass. Most of the remaining decrement was balanced out by lower demand resulting from higher projected electricity prices that stemmed from the higher carbon price. Natural gas prices at the wellhead were also projected to be higher in the biomass limitation sensitivity case, by about $0.13 per thousand cubic feet in 2020 as compared with the projected price in the 1990-7% case.

### Geothermal

Although it is a more limited resource than biomass or wind, geothermal energy has the potential to contribute to the goal of carbon emission reductions. Only hydrothermal resources west of the Rocky Mountains are considered in this analysis. The technologies represented for new generating capacity are dual-flash and binary cycle plants, both of which are currently available. The existing dry-steam capacity at The Geysers is expected to decline as the resource continues to be depleted. Although few domestic orders for new geothermal plants are being placed, the U.S. geothermal industry remains viable because of activity with foreign projects, such as those in Indonesia and the Philippines. Under the Kyoto Protocol, the large U.S. resources, which are costly to develop because of their inaccessibility, could be brought within economic reach. Although little new capacity has been built in the United States in recent years, studies have estimated that more than 27 gigawatts of new capacity could be developed from currently identified resources and as much as 50 gigawatts when potential unidentified resources are included.[65]

In the reference case, geothermal electricity generation is projected to be 17 billion kilowatthours in 2010 and 20 billion kilowatthours in 2020. In the 1990+9% case, geothermal generation is projected to increase to 22 and 33 billion kilowatthours in those years, levels that are 29 percent and 68 percent, respectively, above the reference case projection. In the 1990-3% case, geothermal generation increases to 30 billion kilowatthours in 2010 and 47 billion kilowatthours in 2020. In the reference case, 280 megawatts of new capacity is added by 2010, more than 80 percent of which is built in the Northwest and the remainder in California. In the 1990-3% case, roughly 60 percent of the projected new capacity is built in the Northwest, 35 percent in California, and the remainder in the Southwest. These levels are within estimates of the potential for geothermal development by the California Energy Commission (CEC) and the Northwest Power Planning Council (NPPC). The CEC found more than 3 gigawatts of potential[66] and the NPCC nearly 4 gigawatts of potential in an optimistic case.[67]

### Municipal Solid Waste

Electricity generation from municipal solid waste facilities is not expected to increase beyond the reference case levels of 29 billion kilowatthours in 2010 and 32 billion kilowatthours in 2020, regardless of the carbon reduction target assumed. The economics of these facilities are driven primarily by waste disposal costs (landfill tipping fees), rather than their energy production. After rising in the 1980s, tipping fees have stabilized, and they are not expected to increase significantly. Moreover, efforts to reduce carbon emissions could actually reduce the waste stream available for combustion because of greater emphasis on reusable products, reduced use of packaging materials, and recycling. In addition to their high cost, municipal solid waste facilities are expected to

[65]Energy Information Administration, *Geothermal Energy in the Western United States and Hawaii: Resources and Projected Electricity Generation Supplies*, DOE/EIA-0544 (Washington, DC, September 1991).

[66]California Energy Commission, *Technical Potential of Alternative Technologies* (December 2, 1991).

[67]Northwest Power Planning Council, *Northwest Power in Transition: Opportunities and Risk*, 96-5 (March 13, 1996).

be at a disadvantage in the electricity generation market because of the carbon emissions produced from the petroleum-based portion of the waste stream (primarily plastics), local resistance to their operation, and other environmental factors.

### Solar

A variety of photovoltaic (PV) configurations serve U.S. electricity markets. Grid-connected PV can be (1) large central station units greater than 1 megawatt, (2) smaller distribution-level units less than 1 megawatt, and (3) individual end-user units, usually much less than 20 kilowatts. Off-grid PV always serves individual end uses—for remote buildings, pumps, signals and communications devices and for lighting—where the costs of grid interconnection are high. EIA forecasts include only grid-connected power.

PV is expected to grow steadily over the forecast period, as experience grows and costs decline. In general, increases in electricity prices should imply increasing opportunities for PV technologies. In the reference case, an increase in U.S. grid-connected PV is projected, from just over 10 megawatts in 1996 to 560 megawatts in 2020. No change from reference case levels is expected in the 1990+24% case. In the 1990-3% and 1990-7% cases, grid-connected PV capacity increases more rapidly, exceeding 700 and 900 megawatts by 2020, respectively.[68]

Off-grid PV applications, currently estimated to grow by less than 10 megawatts a year, should expand much more quickly if electricity prices rise, particularly if individual consumers shoulder the full costs of interconnection in locations that are difficult to serve. Furthermore, as costs decline, experience grows, and world demand increases, global markets for U.S. PV output—already absorbing nearly two-thirds of U.S. production—should also enjoy robust expansion. As a result, U.S. production of PV is likely to expand even more rapidly than domestic PV consumption.

Despite the optimistic outlook for PV in cases indicating increasing electricity prices—and despite expected large drops in PV costs—the technology is not expected to become a large component of U.S. electricity supply through 2020. In most instances, central station fossil, nuclear, and other renewable sources will remain far less costly than PV over the forecast period.

Even in the 1990-7% case, central station PV is expected to remain more expensive than alternatives through 2020 in all regions. In the most favorable areas, such as the Southwest, where central station PV costs are projected to decline to around 9 cents per kilowatthour after 2012, electricity generation costs for natural-gas-fired advanced combined-cycle plants are expected to be much lower, around 6 cents per kilowatthour including the carbon price, and to provide power more reliably and for a much greater proportion of the demand cycle. As a result, no new central station PV capacity is expected to be built on a cost-competitive basis.

Distributed PV units less than 1 megawatt are likely to succeed in small numbers in limited circumstances, and they are included, along with small end-user units, in EIA forecasts for grid-connected PV growth. Distributed PV may become competitive where the combination of excellent insolation, transmission or distribution line congestion, and unavailability of natural-gas-fired capacity make PV a cost-effective option. Such combinations, however, are expected to be infrequent.

As costs drop and experience grows, end-user sited PV may grow more rapidly, but it is not expected to become a general source of end-user electricity supply. More individual instances should occur in which delivered peak power can be cost-effectively supplied by grid-connected PV, such as where peak-time distribution line congestion and difficulty in siting new lines raise the costs of power from central station plants. Overall, however, PV is expected to remain costly for almost all applications that could use grid-connected power.

Smaller-scale PV units purchased by retail consumers are likely to cost even more than utility-scale PV. Moreover, grid-using PV consumers could incur some fixed costs of the transmission and distribution system to which they remain connected. And to the extent that utilities incur additional costs from the presence of end-user PV—such as for protecting lines and personnel from intermittent and unexpected electricity flows—users could incur additional costs. As a result, utilities may be unwilling to pay full retail rates for electricity purchases from end-user PV units.

Unlike PV, which uses solar energy to create electricity directly, solar thermal technologies—including trough, central receiver, and dish Stirling—convert solar energy to heat and then to electricity in generating units (usually turbines). The 360 megawatts of trough units built in California in the 1980s constitute almost all the solar thermal units operating today. No additional trough units are planned at this time. One central receiver unit, the 10-megawatt Solar II, is currently being tested. No commercial-scale central receiver units are in operation or planned. Dish-Stirling units are in relatively early testing stages, with only a few kilowatts operating.

Unless breakthroughs are forthcoming, solar thermal appears unlikely to make a notable contribution to U.S. electricity supply, even in the most demanding carbon

[68]Increases in PV capacity were determined exogenously to reflect small, distributed, and end-user applications. Central-station PV was allowed to compete with other central station generating technologies.

reduction cases. Solar thermal suffers a number of disadvantages. Cloud cover and humidity weaken the required (direct) solar radiation sufficiently to eliminate all but the drier Western regions from consideration, and where solar conditions are best the water volumes needed for steam production are in shortest supply. In addition, the technology currently has both high capital costs and limited availability. The facilities cannot operate many hours without storage, but adding energy storage fields to compensate for non-peak solar hours means significant additional capital costs. As a result, central station solar thermal generation is not expected to penetrate U.S. markets significantly before 2020.

### *Hydropower*

Under currently expected circumstances, little additional hydroelectric power is likely to be available to meet U.S. carbon emission reduction targets. Conventional hydroelectricity is the major source of renewable electricity today, supplying about 80 percent of renewable generation and nearly 10 percent of all U.S. electric power in 1996. However, the combination of few additional sites, high capital costs, reduced Federal support, and changing national water-use priorities away from electricity and toward environmental improvements—including for fish, habitat preservation, and recreation—sharply limit the potential for expansion of U.S. hydropower capacity, whether or not carbon reduction measures are required.

In the reference case, U.S. conventional hydroelectric power stays virtually unchanged over the forecast period, annually providing about 313 billion kilowatthours. Because both overall electricity generation and use of other renewables increases, the hydropower shares of both renewable and total generation decline. In 2020, conventional hydropower is projected to provide about 72 percent of U.S. renewable electricity generation and less than 7 percent of total generation.

Increasing carbon reduction requirements are projected to increase reliance on other renewables but have little effect on hydropower. In the 1990+9% case, total renewable generation in 2020 is nearly 44 percent greater than in the reference case, but hydroelectricity remains unchanged. Despite much greater reliance on renewables in the 1990-3% and 1990-7% cases, U.S. conventional hydroelectric power increases only slightly. Even in the 1990-7% case, hydroelectric generation in 2020 is less than 3 percent above the reference case projection. The increases that are projected in this case are primarily from new units at existing dams rather than the addition of new dams. As a consequence, by 2020, conventional hydroelectric generation slips to second place, below biomass, providing about 35 percent of total renewable electricity generation.

## Nuclear

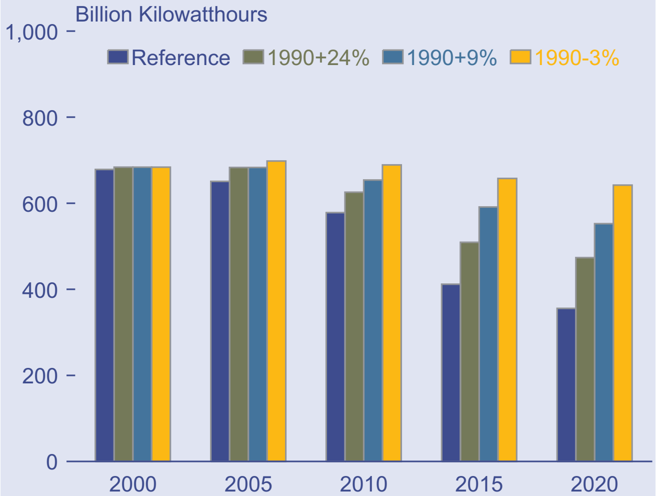
Nuclear generation is expected to be higher in the carbon reduction cases than in the reference case. In the reference case, more than half of the nuclear plants existing today are expected to be retired when their licenses expire. The economics of the retirement versus life extension decision will change, however, if significant reductions in carbon emissions are required.

To simulate this decision process, an approach was developed for evaluating the economic choice of continuing to operate a nuclear plant or retiring it and building a replacement plant. Essentially it was assumed that as nuclear plants age their components will eventually need to be replaced. At that point, the component replacement costs and the plant’s continuing operating costs can be compared to the costs of building and operating another type of generator. Because it is impossible to predict when component replacement costs will be incurred for a particular plant, it was assumed for the sake of simplicity that all nuclear plants would need refurbishment at 30 years and again at 40 years of life. The 30-year point represents the point at which many existing plants are expected to require turbine generator replacements, and the 40-year point represents the point at which plants will have to be prepared for continued operation after their 40-year operating licenses expire.

Even in the 1990+24% case, where the projected carbon price is much less than that in the 1990-3% case, it would be economical to incur the 30-year component replacement cost and continue operating most nuclear plants. For some plants, however, it would not be economical to continue operation after 40 years. With the higher carbon prices in the 1990-3% case, almost all existing nuclear plants would be maintained and continue their current electricity generation levels throughout the projection period (Figure 82). The difference in electricity generation projections between the reference and 1990-3% cases is greater for nuclear than for any other non-carbon-based fuel (see Figure 70). In the absence of that increment in nuclear generation, greater reliance on natural gas and nonhydroelectric renewables would result in even higher generating costs.

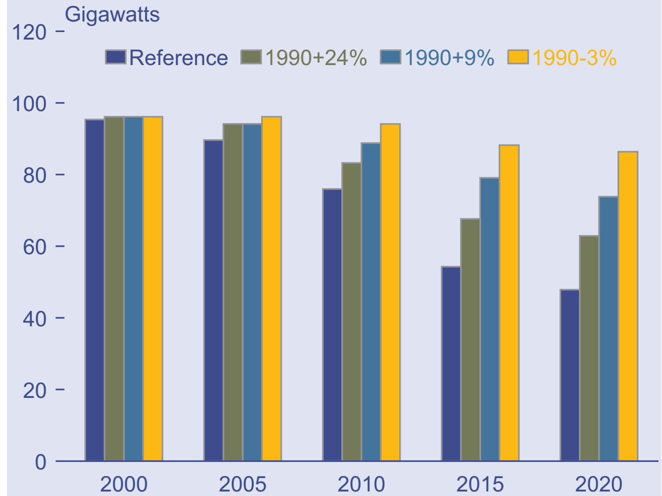
In the 1990-3% case, additional generation from nuclear plants operating beyond 40 years offsets approximately 30 to 40 million metric tons of carbon emissions—approximately equal to the difference between the carbon targets in the 1990-3% and 1990-7% cases. Thus, in the absence of the projected nuclear plant life extensions, projected electricity prices in 2010 in the 1990-3% case would be some 5 percent higher, equivalent to the 2010 price projection in the 1990-7% case.

**Figure 82. Projections of Nuclear Electricity Generation, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

**Figure 83. Projections of Nuclear Electricity Generation Capacity, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

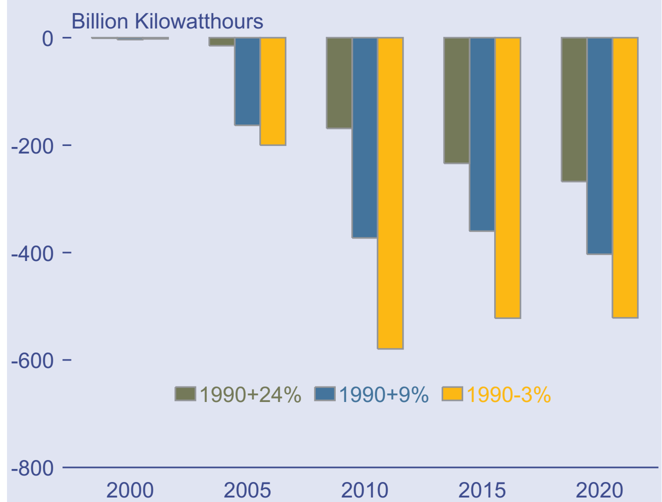
The higher projections for nuclear electricity generation in the carbon reduction cases would have implications for nuclear waste disposal. The projected impact is not significant through 2010, but in 2020 cumulative spent fuel discharges from nuclear units would be 6 percent and 9 percent higher than the reference case projection in the 1990+9% and 1990-3% cases, respectively. The spent fuel calculations assume that all spent fuel will be removed from a reactor when it is retired—a greater amount than would be discharged during a normal year of operation. Thus, even greater differences would be seen if spent fuel projections were calculated over the entire lifetime of all nuclear units.

Nuclear capacity varies significantly across the carbon reduction cases (Figure 83) not because new nuclear plants are built but because existing plants are maintained and life-extended. In the 1990+9% case, the carbon price makes it economical to maintain almost 75 percent of existing U.S. nuclear power capacity throughout the projection period, so that the projected capacity in 2020 is 26 gigawatts higher than in the reference case. With higher carbon prices in the 1990-3% case, it would be economical to keep 86 percent or more of the existing nuclear capacity—roughly 40 gigawatts more than in the reference case—operating through 2020.

### Demand Reduction

Electricity usage decisions by consumers, as discussed in Chapter 3, would also play a large role in reducing electricity sector carbon emissions (Figure 84). Even in the 1990+24% case, consumers would be expected to reduce their electricity consumption by 4 percent in 2010 and 6 percent in 2020 relative to the levels of consumption projected in the reference case. When a more stringent carbon reduction target is assumed in the 1990-3% case, consumer usage decisions are more important. In this case, lower demand for electricity accounts for a large share of the reduction in electricity sector carbon emissions.

**Figure 84. Projected Changes in Electricity Sales Relative to the Reference Case, 2000-2020**



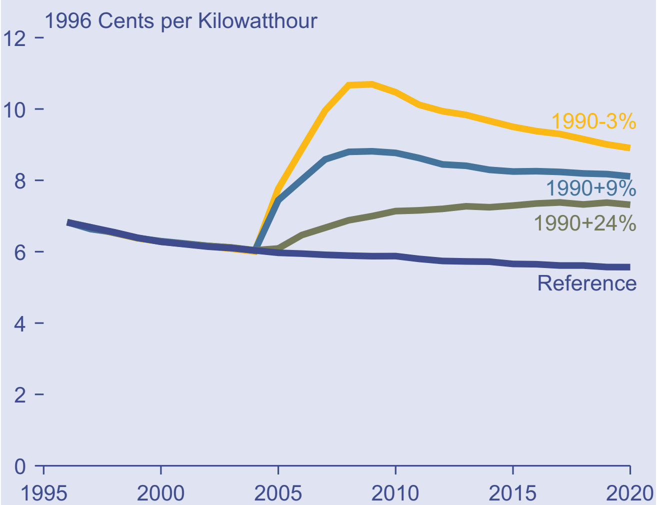

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

## Electricity Prices

While electricity suppliers do have options available for reducing their carbon emissions, it will take financial incentives to encourage them to implement them. In turn, this will have an impact on average electricity prices. In all the cases discussed in this analysis, with the exception of the competitive pricing cases described below, electricity prices are based on average costs in all regions except California, New York, and New England. It is assumed that competitive prices, based on marginal costs, will be phased in over time in those three regions.[69] In other words, the total costs of producing and delivering electricity to consumers are divided by the amount of electricity sold to calculate the average prices. In the carbon reduction cases, electricity production costs include the projected carbon prices. A discussion of competitive electricity markets is provided below.

In all the carbon reduction cases, projected electricity prices are higher than reference case prices beginning in 2005 as the carbon targets are phased in (Figure 85). The highest prices are projected between 2008 to 2012. In subsequent years, as new renewable plants become more economical and the financial incentives needed to ensure their development moderate, electricity prices are expected to decline. In 2009, average electricity prices in the 1990-3% case could be as much as 82 percent higher than in the reference case. The higher prices would lead to higher consumer bills. In 2010, residential consumers would pay $10, $23, and $36 more per month on average in the 1990+24%, 1990+9%, and 1990-3% cases, respectively, than the $70 average monthly bills projected in the reference case.

**Figure 85. Projections of Electricity Prices, 1996-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Regionally, the price impact would be greatest in those regions where generation currently is dominated by coal-fired power plants. Particularly hard hit would be the midwestern ECAR and MAPP regions, where coal-fired generation accounts for 89 and 70 percent of total generation, respectively. In the 1990+9% case, efforts to reduce carbon emissions could lead to an increase of as much as 71 to 78 percent in the price of electricity in the two regions between 2008 and 2010 relative to the prices projected in the reference case. Nationally, prices in the 1990+9% case in 2008 are only 50 percent higher than in the reference case.

The impact on prices could be greater in a more competitive market. The results shown in Figure 85 are based on prices calculated as they have been in the regulated electricity market over the past 50 to 60 years.[70] This may not be appropriate in the near future. The U.S. electric industry is in the midst of a major change in its regulatory pricing structure. Historically, prices have been based on the average cost of producing and delivering electricity to the customer, but in a competitive market this will not be the case.

In a competitive market, prices will be based on the operating costs of the last plant needed to meet demand. On a typical hot summer day, generating plants are brought on line as the demand for electricity grows. Initially, the lowest cost plants (in terms of operating costs) are brought on line, but as consumer needs grow, more costly units are started. At any given time, the price for power will equal the cost of operating the highest cost unit supplying power—the "marginal unit." The operating costs for a typical plant include fuel and operations and maintenance costs and, in a carbon reduction case, the carbon price. Because carbon prices would be included in the operating costs of the marginal plant, they would have a direct impact on the competitive price of electricity. In a regulatory pricing environment the effect of the carbon price would be smaller, because the operating costs for plants with lower carbon emissions would be averaged in with the costs for units with higher emissions.

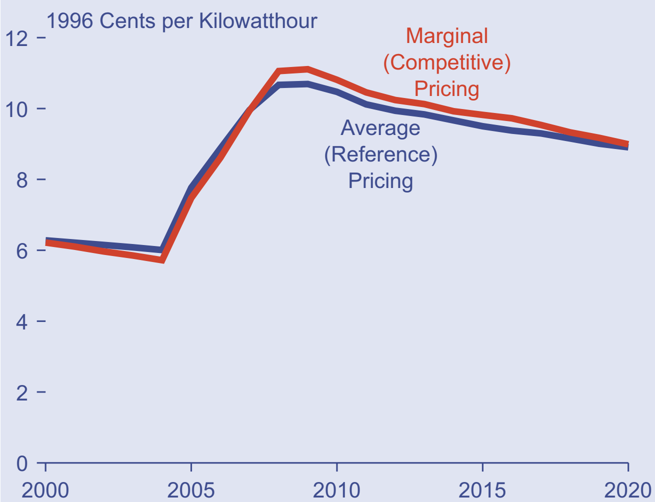
In this analysis, when higher carbon prices are projected, end-use electricity prices are higher under marginal cost (competitive) pricing than they would be under average cost (regulated) pricing (Figure 86). The effect of marginal cost pricing on electricity prices increases with the level of the carbon price. Because the effect is relatively minor in the less stringent carbon reduction cases, the 1990-3% case is examined. In this illustration, the higher prices in the early years under marginal cost pricing cause consumers to reduce their electricity use, resulting in lower generation requirements. Consequently, it is easier for suppliers to meet the carbon reduction goals, and the carbon price is lower than it would be under average cost pricing (Figure 87), although the competitive electricity price remains higher than the average electricity price.

[69]See Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), for a discussion of competitive pricing.

[70]In all cases the California, New York, and New England regions are treated as competitive.

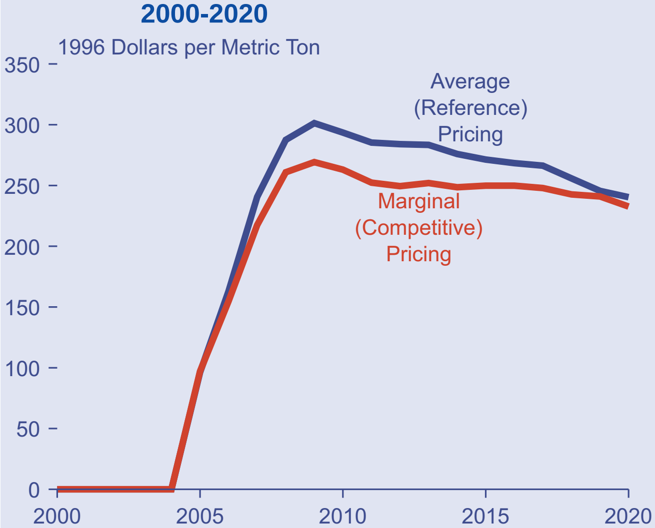
An easy way to see the impact of the carbon price is to look at the impact it has on the types of plants that will set the marginal price of power. A carbon permit system would change the plants that set the market price of electricity in a competitive pricing environment. In a carbon reduction case assuming competitive pricing, the order in which plants are used would differ from that in a corresponding reference case. The coal-fired plants that traditionally serve as baseload generators would be more expensive than the other fossil fuel plants or non-carbon-based technologies (renewables and nuclear) in the competitive pricing carbon reduction case. Therefore, they would be dispatched last and set the marginal price more often.

**Figure 86. Projected Electricity Prices in Regulated and Competitive Electricity Markets, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD03BLW.D080398B and FD03COMP.D080698C.

**Figure 87. Projected Carbon Prices in Regulated and Competitive Electricity Markets, 2000-2020**

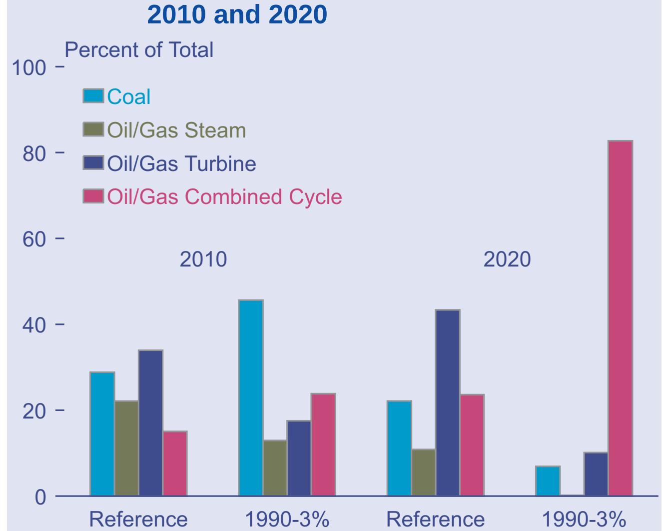



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD03BLW.D080398B and FD03COMP.D080698C.

Figure 88 shows the fraction of time in which each technology would set the margin in a reference competitive case and in a 1990-3% competitive case. In 2010, even though total coal-fired generation is much lower in the 1990-3% case, the amount of time that coal units set the marginal price is greater than in the reference competitive case. In both cases, the marginal plant type shifts from generally older, existing plants (coal and other fossil steam) in 2010 to newer units (combined cycle and combustion turbine) in 2020. Because the carbon price would have a greater impact on plants with higher emissions, the carbon reduction case favors more efficient technologies. Thus, in 2020, the marginal price is most often based on the cost of a new combustion turbine in the reference case, but new combined-cycle units set the marginal price more frequently in the 1990-3% competitive case.

Changing electricity trade patterns are also expected to affect electricity prices. Although no new construction of interregional transmission lines is assumed in this analysis, changes in economy trades still occur. Economy trades take place whenever there is capacity available in a neighboring region that is cheaper than the cost of the marginal plant that would be needed in the home region. For example, in the reference competitive case, Region 1—the East Central Area Reliability Coordination Agreement—is a net exporter of power, because it has a large amount of coal capacity that can be operated inexpensively. In the 1990-3% competitive case, as a result of the carbon price, coal-fired capacity is more expensive to operate than other technologies. In this case, Region 1 becomes a net importer of electricity, finding generation from neighboring regions less expensive than electricity from its coal-fired units. Because the marginal cost of generation in a given region

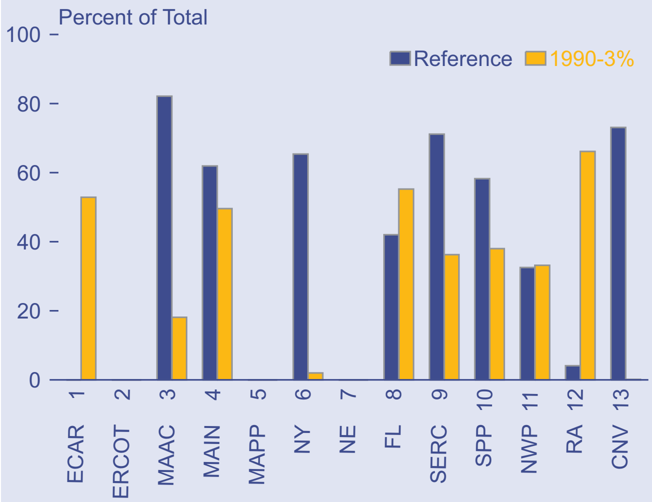
**Figure 88. Projected Percentage of Time for Different Plant Types Setting National Marginal Electricity Prices, 2010 and 2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYCOMP.D080598A and FD03COMP.D080698C.

is the cost after economy trades are made, changes in trade patterns directly affect competitive prices. Figure 89 shows the fraction of time in which a trade is responsible for setting the marginal price in each region in 2020.

**Figure 89. Projected Percentage of Time for Interregional Trade Setting Marginal Electricity Prices, 2020**




Note: ECAR = East Central Area Reliability Coordination Agreement Region; ERCOT = Electric Reliability Council of Texas; MAAC = Mid-Atlantic Area Council; MAIN = Mid-America Interconnected Network; MAPP = Mid-Continent Area Power Pool; NY = New York Power Pool; NE = New England Power Pool; FL = Florida subregion of the Southeastern Electric Reliability Council; STV = Southeastern Electric Reliability Council excluding Florida; SPP = Southwest Power Pool; NWP = Northwest Pool subregion of the Western Systems Coordinating Council; RA = Rocky Mountain and Arizona-New Mexico Power Areas; CNV = California-Southern Nevada Power Area.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYCOMP.D080598A and FD03COMP.D080698C.

# Sensitivity Cases

## Technological Progress

The development and market penetration of new technologies for consumer use (new air conditioners, furnaces, refrigerators, etc.) and for supplier use (new generation, transmission, and distribution equipment) will have a significant impact on the feasibility and costs of meeting the Kyoto Protocol targets in the U.S. electricity sector. All the carbon reduction cases in this analysis include substantial improvements in technology, mainly as a function of market penetration. For example, in the reference case the cost of new advanced combined-cycle plants declines from a starting point of $572 per kilowatt to $400 per kilowatt, a 30-percent improvement. In addition, the thermal efficiency of the same technology improves by roughly 10 percent. The situation is similar for wind plants, the cost of which falls from around $1,000 per kilowatt to under $750 per kilowatt. It is possible that further improvements might occur; however, it is impossible to predict to what degree a concerted effort to reduce carbon emissions might stimulate the development of new technologies or reduce the costs of existing ones.

As described in Chapter 2, to look at the potential impacts of technological innovation, development, and market penetration, a set of low (currently available) technology and high technology sensitivity cases were developed. In the 1990+9% low technology case, the new generating options available were limited to technologies available in 1998. In the 1990+9% high technology case, cost and performance characteristics were assumed to improve at rates consistent with those used in the high technology sensitivity cases in the *Annual Energy Outlook 1998*.

The performance and cost data used in the high technology cases are considered optimistic but not unreasonable. In addition, two new plant types, coal gasification with carbon sequestration and natural gas combined cycle with carbon sequestration were made available beginning in 2010 in the high technology case. The uncertainty involved in selecting aggressive cost and performance values for different technologies is considerable. Thus, the results of these sensitivity cases should not be viewed as indicating which technologies are most promising but, rather, as indicative of the extent to which technological innovation might lower the costs of meeting carbon emission reduction targets.

The key result of the high technology cases is that if new, more efficient, lower cost technologies evolve, the cost of meeting the Kyoto Protocol targets could be lowered significantly. The most important of the generating technologies appears to be the advanced natural gas combined cycle; however, as pointed out above, this is a product of the high technology assumptions, and it is impossible to say which technology might progress the most.

Figure 90 shows the average heat rate (number of Btu needed to generate each kilowatthour of electricity) for all natural-gas-fired generating plants. Even in the low technology case, the average heat rates for natural gas plants are expected to improve significantly. The improvement is greater in the 1990+9% case and even greater in the 1990+9% high technology case.

The effects of assuming lower and higher rates of technological progress on electricity prices in the carbon reduction cases are significant. For example, in 2010, projected electricity prices in the 1990+9% low technology case are more than 70 percent higher than those in the reference case (Figure 91). In the 1990+9% case and the 1990+9% high technology sensitivity case, they still are higher than in the reference case, but by only 49 and 36 percent, respectively. In 2020 the price difference remains quite high in the low technology case but is only 45 percent and 13 percent in the 1990+9% and

1990+9% high technology cases, respectively. Neither of the carbon sequestration technologies penetrates the market in the 1990+9% high technology case, because the projected carbon price is relatively low, and other high-technology options are more attractive.

## Nuclear Power

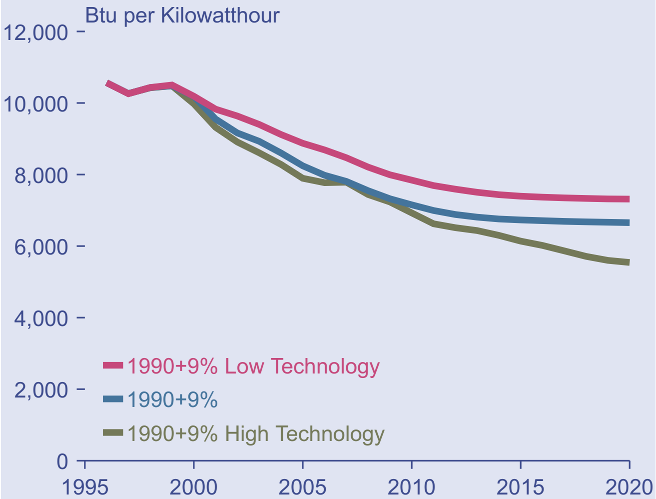
One carbon-free technology around which there is considerable uncertainty is new nuclear power plants. Currently nuclear power accounts for 20 percent of the power produced in the United States; however, no new nuclear power plants have been ordered since 1978, and the last one to come on line was Watts Bar 1 in 1996. In recent years, the overall performance of existing plants has improved dramatically (although several older units were retired before their 40-year operating licenses expired). In addition, manufacturers are now working on designs for a new generation of nuclear power plants, which are expected to be safer and less costly. As with any new technology the first few newly designed units are likely to be quite expensive, but costs should fall as manufacturers and regulators gain experience with them.

A special sensitivity case was used in this analysis to examine the possible impacts of new nuclear power plants on the carbon reduction cases. Because new nuclear plants are not economical in the 1990+9% case, this sensitivity was analyzed against the 1990-3% case. The 1990-3% nuclear sensitivity case assumes a carbon emissions target 3 percent below 1990 levels and new nuclear plant costs about 8 percent lower than the costs typically associated with the early units of new technologies, with rapidly declining costs as the new technology penetrates the market.

In the 1990-3% nuclear sensitivity case, about 40 gigawatts of new nuclear capacity is built, mostly in the later part of the projection period (Figure 92). With higher carbon prices and lower initial construction costs, the new plants are becoming competitive with other generating technologies. Nuclear electricity generation in the 1990-3% nuclear sensitivity case is only 9 billion kilowatthours higher than in the 1990-3% case in 2010 but is 248 billion kilowatthours higher in 2020.

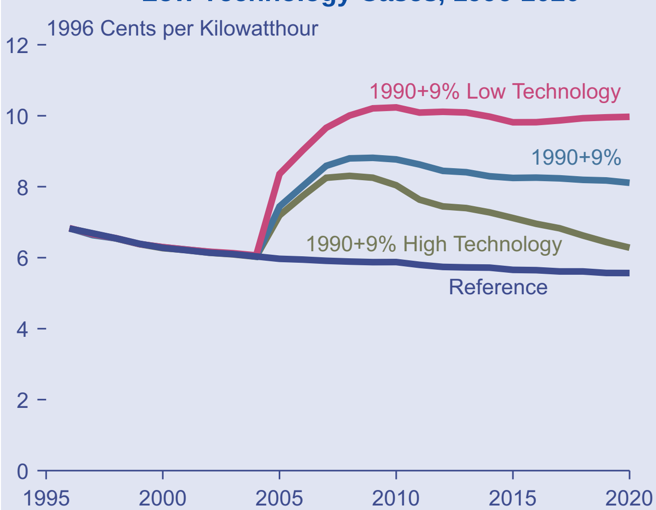
As discussed above, increases in nuclear capacity and generation will result in greater amounts of spent nuclear fuel discharged from nuclear generating units. The waste must ultimately be moved to a permanent storage facility. The 1990-3% nuclear sensitivity case results in a 15-percent increase in projected cumulative

**Figure 90. Projections of Average Heat Rates for Natural-Gas-Fired Power Plants in High and Low Technology Cases, 1996-2020**



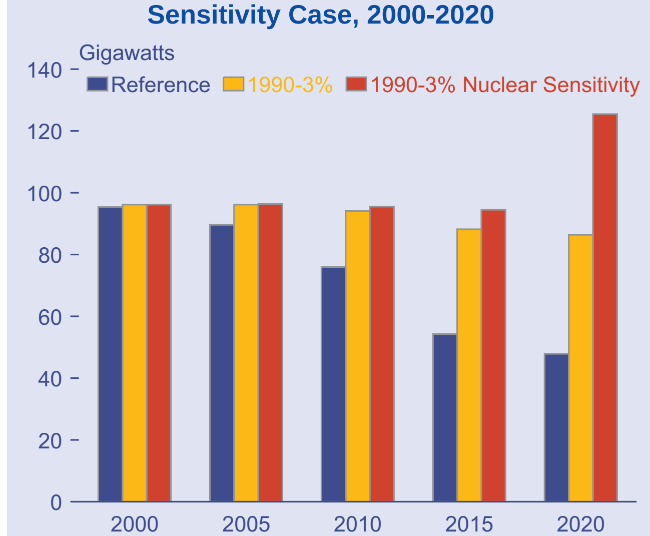

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

**Figure 91. Projected Electricity Prices in High and Low Technology Cases, 1996-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FREEZE09.D080798A, FD09ABV.D080398B, and HITECH09.D080698A.

**Figure 92. Projections of Nuclear Generating Capacity in the 1990-3% Nuclear Sensitivity Case, 2000-2020**




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD03BLW.D080398B, and NUKE03LC.D081298A.

spent fuel discharges by 2020, relative to the reference case.

The future of nuclear power in the United States is uncertain. Indeed, it may depend on the extent to which limits are set on carbon emissions in response to the Kyoto Protocol. The reference and carbon reduction cases in this analysis assume no new nuclear construction, for several reasons. One is concern about the future of nuclear waste disposal. The Nuclear Waste Policy Act of 1982 directed the U.S. Department of Energy (DOE) to begin accepting spent fuel for permanent disposal in 1998. As yet, however, no permanent waste storage site is available, and most of the waste is still being stored on-site by the utilities that operate nuclear power plants. The current schedule projects 2010 as the earliest that the proposed site at Yucca Mountain could begin accepting waste. Given the history of schedule slippage in the waste repository project, new investors may not commit to new nuclear power construction until they are certain that DOE will be prepared to handle the waste. In addition, public concerns about the safety of both plant operations and waste disposal will need to be addressed. The public's association of nuclear power with its weapons origin, along with highly publicized accidents at Three Mile Island and Chernobyl, have heightened safety concerns. Public opposition can cause delays in project approval, adding risk to investments in nuclear power.

Another uncertainty is the cost of new nuclear construction. If another nuclear reactor is built in the United States, it will be one of several new designs that have been approved by the U.S. Nuclear Regulatory Commission (NRC). Two evolutionary designs have received final approval from the NRC, and one "passively safe" design is still being reviewed. The nuclear industry hopes that creating relatively few, standardized designs will bring down construction costs and reduce the time needed to build future plants. However, past experience suggests that there will be considerable uncertainty until the first new units have actually been completed. No nuclear plant operating in the United States today was built at its initial estimated cost or schedule. Instead, all faced both cost overruns and delays in completion.

There is also uncertainty about the useful lifetimes of currently operating nuclear reactors. In recent years, a number of nuclear plants have been permanently shut down well before their license expiration dates, mainly because of the availability of more economical generation. Operating a nuclear unit for a full 40 years (the license life) will generally require additional capital expenditures over the last 10 to 15 years of the plant's life. Whether or not it is economical to incur such costs will depend on factors specific to each plant, such as location, other types of generation available, and fuel prices.

If limitations are placed on carbon emissions in the future, the relative costs of electricity generation could shift in favor of nuclear power. This analysis assumes that license renewal for nuclear plants will be considered, if economical, in all cases with restrictions on carbon emissions. Operators of nuclear power plants that are economical will renew the plant licenses, incurring the costs assumed to be necessary to prepare the plant for an additional 20 years of operation. In 1998, two utilities—Baltimore Gas & Electric and Duke Power—filed applications to renew the operating licenses of existing plants, the Calvert Cliffs units in Maryland and the Oconee plant in South Carolina. The approval process is likely to be lengthy for the first few plants, but as the NRC develops a standard review process, more utilities may consider license renewal a viable option.

### Reducing the Impact on the Coal Industry

Coal is the most carbon-intensive fuel used for electricity production. The carbon emission rate for coal is 78 percent higher than that for natural gas, which has the lowest rate among the fossil fuels. Consequently, carbon reduction strategies are expected to affect coal more than other energy sources. Because of their heavy reliance on coal, electricity generators have historically produced more carbon than the other energy sectors. In 1996, more than one-third of U.S. carbon emissions resulted from electricity production.

Reductions in carbon emissions in the electricity sector are expected to occur primarily as a result of switching from coal to fuels with lower emission rates, such as natural gas and renewables. Initially, fuel switching occurs mostly by changing the utilization of existing capacity. That is, coal-fired plants are operated less frequently and gas-fired units are used more extensively. Later on, additional fuel switching results as new capacity is built to replace electricity from existing coal units.

Historically, electric utilities have accounted for most of the coal consumption in the United States. Therefore, fuel switching to reduce carbon would seriously affect the coal industry. In the 1990+9% case, utility coal use in 2020 is projected to be 78 percent lower than in the reference case. In the 1990-3% case, coal consumption for electricity production would be nearly eliminated in 2020. Absent significant changes in other sectors, continued use of coal in the electricity generation sector is not economical in the 1990+9% case. Substantially lower coal use would likely have dramatic impacts on mining employment, as fewer miners would be needed, and on the railroads, whose transportation of the coal used in power plants would decline dramatically.

*(Continued on page 94)*

## Reducing the Impact on the Coal Industry (Continued)

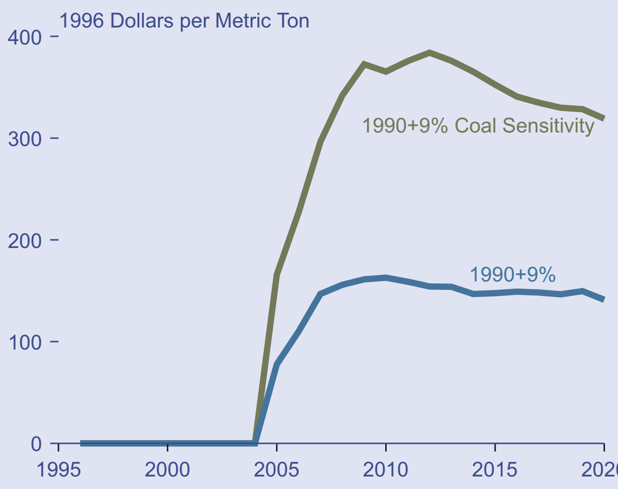
In the carbon reduction cases, the projected utilization rates for coal-fired generating capacity are much lower than the rates at which they have traditionally been operated. Many coal plants are designed as baseload capacity that operates almost continuously because they cannot be restarted quickly or efficiently. The low utilization rates in the carbon reduction cases are more typical of peaking or reserve capacity, which is run infrequently. It is unclear whether coal plants, particularly the larger units, can be operated either efficiently or economically in this manner.

For purposes of energy security, it may be advisable to maintain a broad portfolio of fuel options, including some coal. Coal is the largest domestic energy source and accounts for most of U.S. energy exports. In contrast, imports already represented over half of oil supplies in 1996, and imports are projected to make up more than 15 percent of natural gas supplies by 2020 in the reference case. Consequently, fuel switching from coal to gas would increase U.S. dependence on foreign energy sources. Renewable technologies, such as wind and biomass, are relatively new, and the projected capacity in the carbon reduction cases far exceeds existing capacity, particularly in the 1990-3% case.

With these issues in mind—the impacts on the coal and railroad industries, efficient operation of generating units, and energy security—a coal sensitivity case was prepared that maintained a share of the coal-fired electricity generation that would otherwise be lost. For the 1990+9% case, the carbon price for coal was adjusted, on a Btu basis, to be equivalent to that for natural gas. Because the utilization rates for coal-fired and gas-fired capacity are determined by the delivered prices and operating efficiencies for the respective fuels, the impact on coal in the sensitivity case was significantly reduced. Although coal use would still be lower because of reduced electricity demand and higher renewable capacity levels, utilization rates for coal units would more closely resemble current levels, because the adjustment effectively maintains the historical cost advantage of coal over natural gas.

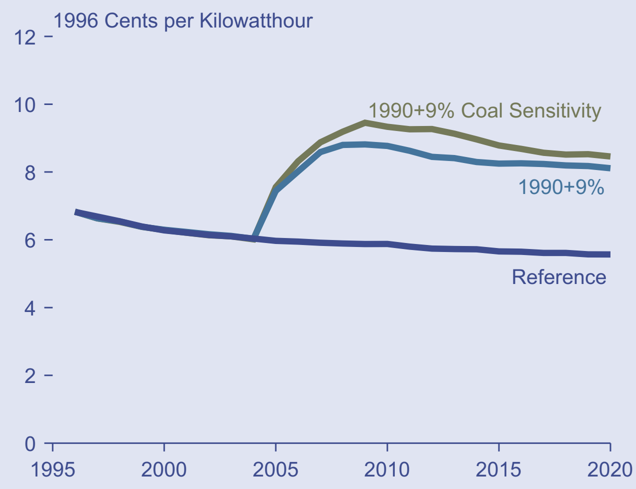
The key result of the 1990+9% coal sensitivity case is that subsidizing some portion of the coal industry would make it more difficult to reach carbon emission reduction targets, significantly raising both the carbon price and the price of electricity (see figures below). In the 1990+9% coal sensitivity case, the projected carbon price in 2010 is 124 percent higher than the carbon price in the 1990+9% case, and the price of electricity is 6 percent higher. (The impact on electricity prices is dampened by the reduced carbon price for coal users.) The impact on fossil fuel prices other than coal is also large. In 2020, the differences from the 1990+9% case are 126 and 5 percent, respectively. In contrast to the impact in the 1990+9% case, the reduction in coal use in the sensitivity case is significantly moderated. By 2020, the reduction in coal consumption by electricity producers would be only 41 percent relative to the reference case projection.

### Projected Carbon Prices in the Coal Sensitivity Case, 1996-2020




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs FD09ABV.D080398B and HICOAL09.D080998B.

### Projected Electricity Prices in the Coal Sensitivity Case, 1996-2020




Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD09ABV.D080398B, and HICOAL09.D080998B.