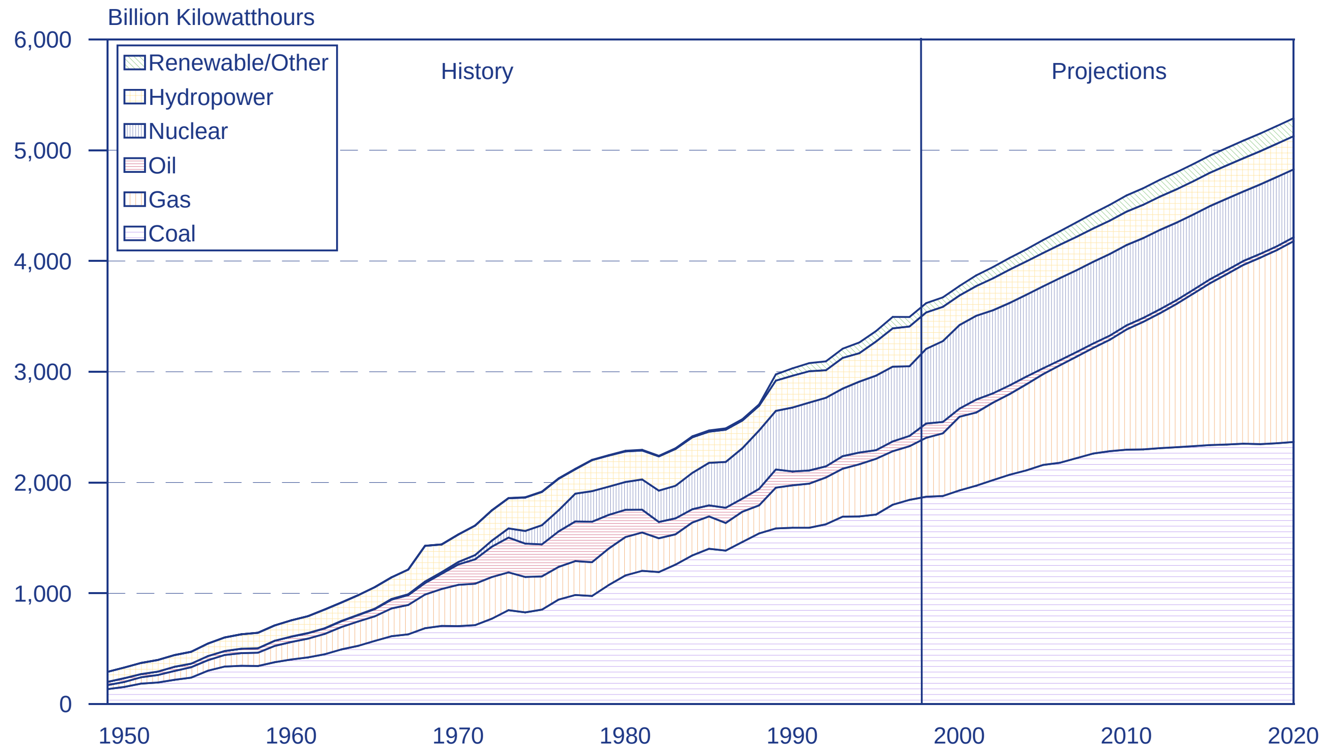
3. Electricity Market Impacts

Introduction

For the past 50 years, electricity production in the United States has been dominated by electric power plants that burn fossil fuels. Beginning with small hydroelectric facilities in the early 20th century, the industry soon turned to fossil fuels, particularly coal. An abundance of economical coal has made it the dominant fuel in U.S. electricity production since 1950 (Figure 3). Changes occurred as relative fuel prices varied and new generating technologies evolved, but coal continued to account for more than one-half of total generation. For example, in the early 1970s oil use increased, but the price increases and regulatory changes of the late 1970s and early 1980s led to a rapid decline in the use of oil by the mid-1980s. The role played by nuclear power also grew in the 1970s and 1980s, when a large number of nuclear plants were constructed. The contribution from nuclear plants continued to grow in the 1990s because of performance improvements at existing plants, but no new plants have been ordered in the past 25 years. Renewables, predominantly hydroelectric power, currently provide between 9 and 11 percent of total generation, depending on the availability of water from year to year.

Over the next 20 years coal use for power generation is expected to continue to grow, but at a slower rate than in the past. Only a relatively small number of new coal-fired plants are expected to be built, and existing coal plants are projected to be used more as demand for electricity grows. When new plants are needed, natural-gas-fired combustion turbines and combined-cycle plants are expected to be the most economical options for most uses. New natural-gas-fired combined-cycle plants cost approximately half as much to build as new coal-fired plants, are more efficient, and have lower emissions. These factors generally offset the higher fuel cost for natural gas. Unless the high gas prices seen recently are sustained for many years, new natural gas plants are expected to dominate new plant additions. Oil-fired generation is expected to continue to decline while total renewable generation increases slightly in the overall generation mix. Nuclear power is projected to continue to contribute, but some older nuclear plants are expected to be retired in the later years of the

Figure 3. Electricity Generation by Fuel, 1949-1999, and Projections for the Reference Case, 2000-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run M2BASE.D060801A.

forecast, and no new nuclear plants are projected to be built in the United States through 2020.

This chapter discusses the impact that the imposition of a renewable portfolio standard (RPS) and emission caps on nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg), and carbon dioxide (CO_2) is projected to have on electricity generation. The RPS and emission caps are expected to affect capacity planning and plant retirement decisions, investments in emissions control equipment, fuel choices for generation, electricity costs, and consumer prices. In turn, higher electricity prices are projected to cause consumers to alter their electricity use by buying more efficient appliances, switching to other fuels, or generating their own electricity. Potential impacts on total CO_2 emissions are also discussed, as well as key uncertainties in the analysis.[20]

Analysis of NO_x and SO_2 Caps

In the reference case, existing laws and regulations affect the projections of power sector NO_x and SO_2 emissions. NO_x emissions are projected to increase slightly between 2000 and 2003 before declining in 2004, when the 19-State summer season NO_x SIP Call and existing regulations will require stringent summertime controls. The main compliance strategy for meeting the SIP Call emission limits is expected to be the installation of emission control equipment at existing electric power plants. SO_2 emissions are expected to decline steadily as the Clean Air Act Amendments of 1990 (CAAA90) Phase II 8.95 million ton cap takes effect and allowances previously banked by power companies are used. By 2010 the banked allowances are projected to be exhausted, and electricity generators are expected to comply with the 8.95 million ton annual cap on SO_2 emissions through the remainder of the projections. The main compliance strategy for reducing SO_2 emissions is expected to be a growing shift toward lower sulfur coal. Scrubbers are also expected to be added to a relatively small number of plants to reduce their emissions.

When tighter NO_x and SO_2 emission caps are assumed, the amount of emission control equipment added is projected to increase dramatically (Table 7).[21] For example, in the NO_x 2008 case, selective noncatalytic reduction (SNCR) or selective catalytic reduction (SCR) equipment is projected to be added to 274 gigawatts of existing capacity, as compared with 136 gigawatts in the reference case. In the SO_2 2008 case, scrubbers are projected to be added to 139 gigawatts of existing capacity, compared with 15 gigawatts in the reference case. The tighter NO_x and SO_2 caps also are projected to have dramatic impacts on the prices of emissions allowances, particularly for SO_2. The SO_2 allowance price in 2010 is projected to be $187 per ton in the reference case but $794 per ton in the SO_2 2008 case. In the SO_2 2008 case, scrubber additions at some plants using medium- or low-sulfur coal lead to higher average costs per ton of SO_2 removed. The NO_x allowance prices in the reference and NO_x 2008 cases are not comparable, because the reference case represents a 5-month summer season NO_x cap in 19 States, while the NO_x 2008 case represents a nationwide annual cap on NO_x emissions. In general, the NO_x allowance prices under an annual cap are expected to be less than those under a seasonal cap, because the costs associated with investments in control equipment are spread over the entire year rather than just the summer.[22]

NO_x emissions are expected to fall to the 1.6 million ton cap by the target date of 2008 in the NO_x 2008 case. In the SO_2 2008 case, however, it is assumed that electricity suppliers will be allowed to use any allowances they have already accumulated under the CAAA90 SO_2 program. Coming into 2000 electricity suppliers had accumulated nearly 12 million tons of SO_2 allowances. As a result, the SO_2 emission level in the SO_2 2008 case is not expected to meet the 3.3 million ton cap until 2011, 3 years after the cap first takes effect.

The addition of emissions control equipment and other steps taken to reduce emissions in the NO_x 2008 and SO_2 2008 cases are expected to have an impact on electricity prices and electricity supplier costs. From 2008 to 2020, annual revenues from retail electricity sales are expected to average $1 billion to $2 billion more in the NO_x 2008 and SO_2 2008 cases than in the reference case, and from 2005 to 2015, overall average electricity prices are projected to be 1 percent higher than in the reference case. In the NO_x 2008 case electricity suppliers are projected to

[20]This analysis employs a no-cost cap and trade system for emissions allowances for all required emission reductions. For a discussion of the impacts of alternative policy instruments see J.A. Beamon, T. Leckey, and L. Martin, "Power Plant Emission Reductions Using a Generation Performance Standard," web site www.eia.doe.gov/oiaf/servicerpt/gps/pdf/gpsstudy.pdf (April 2001); and D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul, *The Effect of Allowance Allocation on the Cost and Efficiency of Carbon Emission Trading* (Washington, DC: Resources for the Future, April 2001).

[21]Sensitivity cases with less stringent NO_x and SO_2 caps were prepared in the earlier EIA report. See Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide,* SR/OIAF/2000-05 (Washington, DC, December 2000).

[22]For similar NO_x allowance price results with an annual versus a seasonal NO_x emission cap, see K. Palmer, D. Burtraw, R. Bhanvitkar, and A. Paul, "Restructuring and Cost of Reducing NO_x Emissions in Electricity Generation," Resources for the Future Discussion Paper 01-10 (Washington, DC, March 2001); and D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul, "Cost-Effective Reduction of NO_x Emissions from Electricity Generation," Resources for the Future Discussion Paper 00-55 (Washington, DC, December 2000).

spend $13 billion on SCRs, and in the SO_2 2008 cases they are projected to spend $33 billion on SO_2 control equipment.

The addition of equipment to reduce SO_2 in the SO_2 2008 case is also projected to reduce Hg emissions, because scrubbers designed primarily to reduce SO_2 also reduce Hg emissions. Hg emissions are projected to be 45 tons in 2020 in the reference case, compared with 33 tons in the SO_2 2008 case, a 28-percent difference.

While the projected average price impacts in the NO_x 2008 and SO_2 2008 cases are not large, the potential exists for other impacts in the short run. The amount of emission control equipment needed in the NO_x 2008 and SO_2 2008 cases[23] could cause operational problems for electricity grids under some conditions. Typically, when new emissions controls are added, particularly SCRs, a plant must be off line for a time so that final connections can be made. Several recent studies have examined whether the outage times (beyond normal maintenance outages) required to make final connections for equipment needed to meet the NO_x SIP Call might create problems for system operation and reliability. While the results of the studies differed, several factors were identified as critical to the analysis, including the calendar time between the announcement of the program and the compliance date, the growth in demand for electricity, the availability of sufficient reserve capacity, coordination among companies performing the work on their plants, and the interconnection time needed for each plant.[24]

Table 7. Key Results for the Electricity Generation Sector in NO_x and SO_2 Emission Cap Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference	NO_x 2008	SO_2 2008	Reference	NO_x 2008	SO_2 2008
Emissions (Tons)							
Hg	43	46	44	32	45	44	33
SO_2 (Millions)	12.7	9.7	9.7	3.6	8.9	8.9	3.3
NO_x (Millions)	5.7	4.3	1.6	4.3	4.5	1.6	4.5
CO_2[a]	556	693	687	684	777	770	775
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	NA	NA	NA	NA	NA
SO_2 (per Ton)	207	187	198	794	241	203	983
NO_x (per Ton)	NA	4,391	2,405	3,668	5,037	3,201	5,229
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.23	6.17	6.21	6.24	6.21
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,270	2,237	2,366	2,339	2,321
Oil and Other	106	50	47	38	49	46	41
Natural Gas	593	1,085	1,105	1,135	1,813	1,832	1,854
Nuclear	734	725	725	725	613	617	613
Renewable	401	440	439	449	452	452	460
Total	3,728	4,597	4,587	4,585	5,294	5,286	5,289
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	6	125	15	19	139
SCR	0	93	237	85	93	242	86
SNCR	0	26	22	38	43	32	45

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NOX08.D060801A, and M2SO208P.D061201A.

[23]The earlier EIA report included cases with a 2005 target date. The earlier date increases the potential for short-term reliability and pricing problems.

[24]North American Electric Reliability Council, *Reliability Impacts of the EPA NO_x SIP Call* (Washington, DC, February 2000); U.S. Environmental Protection Agency, *Feasibility of Installing NO_x Control Technologies by May 2003* (Washington, DC, September 1998); and Utility Air Regulatory Group, *The Impact of EPA's Regional SIP Call on Reliability of the Electric Power Supply in the Eastern United States* (Washington, DC, September 1998).

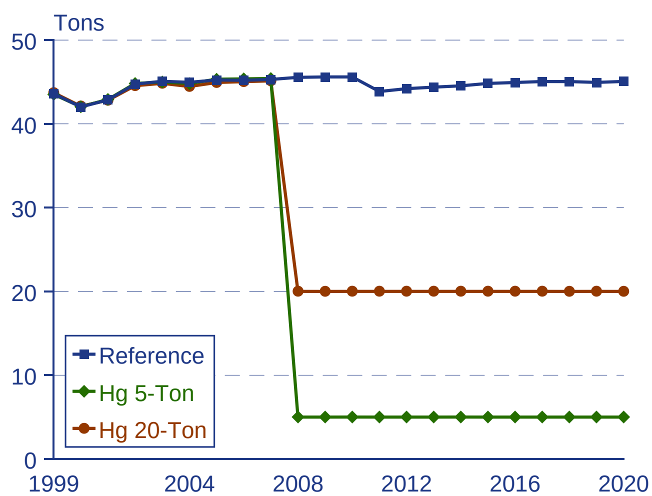
Analysis of Hg Emission Caps

In the reference case, power sector Hg emissions are projected to remain fairly steady over the next 20 years (Figure 4). From 42 tons in 2000, they are projected to reach 46 tons in 2010 and 45 tons in 2020. Although power sector coal consumption is projected to increase by 23 percent over the next 20 years, the shift to relatively low Hg western coal and the addition of scrubbers to 15 gigawatts of capacity to reduce SO_2 emissions to comply with the requirements of CAAA90 Phase II dampen the increase in Hg emissions that would otherwise be expected. In the first few years of the projections, power sector Hg emissions are projected to increase slightly as coal use grows, but as the shift to low-sulfur western subbituminous coal to reduce SO_2 emissions continues, the increase levels off by the middle years of the projections. Between 2000 and 2020 the average Hg content of the coal used in the power sector is projected to fall from 7.36 pounds per trillion Btu to 7.03 pounds per trillion Btu, a 5-percent decline.

The actions projected to be taken to reduce Hg emissions, their costs, and their price impacts are sensitive to the emission cap level, the assumptions made about the cost and performance of Hg removal technologies, and the policy instrument used to reduce them. Data on Hg emissions and technologies for reducing them have been collected in recent years, but significant uncertainty remains. Readers should keep this in mind when reviewing the results presented here. In addition, the rapid reductions shown in Figure 4 may be difficult to achieve.

In the Hg 5-ton case, which assumes a 5-ton annual cap on national Hg emissions in the power sector beginning in 2008, the shift to coal with lower Hg content is expected to be more pronounced than in the reference case (Table 8). Between 2000 and 2020 the average Hg content of the coal used in the power sector is projected to decline from 7.36 pounds per trillion Btu to 6.28 pounds per trillion Btu, a 15-percent reduction. Even with this shift, however, it is expected that power plant operators will need to use activated carbon injection at many plants to reach the 5-ton cap. Supplemental fabric filters and activated carbon injection systems are projected to be added to approximately 263 gigawatts of coal-fired capacity, or 84 percent of the total. At nearly all coal-fired power plants, some action would need to be taken to reduce Hg emissions.

Figure 4. Projected Electricity Generation Sector Mercury Emissions in the Reference, Hg 5-Ton, and Hg 20-Ton Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, and M2M6008.D060801A.

It should be noted that the Hg content of coal burned at all U.S. electric power plants totals about 73 tons annually. Therefore, a 5-ton annual cap on Hg emissions would require that, on average, 93 percent of the Hg initially contained in the coal burned for power production would have to be removed. At many plants, in order to accomplish reductions of that magnitude, activated carbon injection would have to be employed at rates that have never been tested. Thus, there is significant uncertainty about the results. In addition, the amount of activated carbon that must be injected per pound of Hg removed increases as the percentage removal grows. In other words, the amount of activated carbon needed to remove the second pound of Hg is larger than the amount needed to remove the first pound, and the amount needed to remove the third pound is larger still. In economists' terms, the marginal cost of injecting activated carbon to remove Hg increases as the quantity to be removed grows.

Although the removal cost per pound of Hg is expected to be fairly high, its impact on the economics of operating coal plants is not expected to be large for most plants. As a result, the Hg cap is not projected to cause a large change in fuel use for electricity generation. Relative to the reference case, natural gas use is expected to be higher and coal use lower in the Hg 5-ton case. In addition, because more than 90 percent of capacity additions in the reference case are projected to be natural-gas-fired plants (which do not produce Hg emissions), their economic attractiveness is not expected to be affected by the Hg cap. The projected level of generation from renewable fuels in the Hg 5-ton case is also similar to that in the reference case.

Allowance prices for Hg emissions are projected to be much higher than those for NO_x and SO_2, for several reasons. First, the volume of Hg produced by a typical coal-fired power plant is dramatically smaller than the volume of NO_x or SO_2 produced. For example, a 500-megawatt coal plant with a cold-side electrostatic precipitator and no scrubber, using bituminous coal with an Hg content of 7 pounds per trillion Btu and

1 percent sulfur by weight, would produce more than 27,000 tons of SO_2 annually but only 230 pounds of Hg. As a result, even if the total costs of removing 90 percent of the SO_2 or 90 percent of the Hg were the same, the costs per unit removed would be much higher for Hg than for SO_2. Second, as mentioned previously, the cost per pound of Hg removed by activated carbon injection increases as more is removed. Figures 5 and 6 illustrate this point for a common coal plant configuration—a plant with a cold-side electrostatic precipitator, no SO_2 scrubber and no post-combustion NO_x control, using bituminous coal containing 10 pounds of Hg per trillion Btu of coal, and employing simple activated carbon injection.

As shown in Figure 5, the average cost of removing Hg using activated carbon injection increases as the total percentage removed grows. To achieve 90 percent removal, the average cost of Hg removed is over $70,000 per pound.[25] While the average and marginal cost values vary considerably among different coal plant configurations—the one shown is relatively high cost—the relationship between them is consistent: average costs are much lower than marginal costs, and the marginal costs tend to increase rapidly as the degree of removal increases. In addition, as shown in Figure 6, the per-pound costs of removal increase significantly when the total percentage removed increases from 80 percent to 90 percent. The cost of removing the last unit of Hg to achieve 90 percent removal is over $800,000 per pound.

Efforts to meet the 5-ton Hg cap are projected to have significant impacts on SO_2 and NO_x emissions and allowance prices. Because scrubbers designed to remove SO_2 and SCR equipment designed to remove NO_x are also projected to be added to reduce Hg emissions, the allowance prices for SO_2 and NO_x are expected to be lower than they are in the reference case. In fact, in the later years of the projections SO_2 allowance prices are at or near zero in the Hg 5-ton case. Scrubbers are projected

Table 8. Key Results for the Electricity Generation Sector in Hg Emission Cap Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference	Hg 5-Ton	Hg 20-Ton	Reference	Hg 5-Ton	Hg 20-Ton
Emissions (Tons)							
Hg	43	46	5	20	45	5	20
SO_2 (Millions)	12.7	9.7	8.8	9.7	8.9	7.2	9.0
NO_x (Millions)	5.7	4.3	3.3	3.4	4.5	3.5	3.5
CO_2[a]	556	693	664	684	777	748	769
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	178,959	72,519	NA	193,973	68,918
SO_2 (per Ton)	207	187	0	0	241	0	12
NO_x (per Ton)	NA	4,391	2,651	3,669	5,037	4,545	4,645
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.38	6.23	6.21	6.37	6.28
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,134	2,237	2,366	2,200	2,318
Oil and Other	106	50	49	48	49	51	52
Natural Gas	593	1,085	1,218	1,133	1,813	1,951	1,847
Nuclear	734	725	725	725	613	613	617
Renewable	401	440	444	439	452	459	452
Total	3,728	4,597	4,570	4,583	5,294	5,273	5,285
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	18	43	15	52	43
SCR	0	93	95	92	93	99	100
SNCR	0	26	23	26	43	25	30
Hg Emission Controls							
Spray Cooling	0	0	241	34	0	254	40
Fabric Filter	0	0	261	38	0	263	43

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, and M2M6008.D060801A.

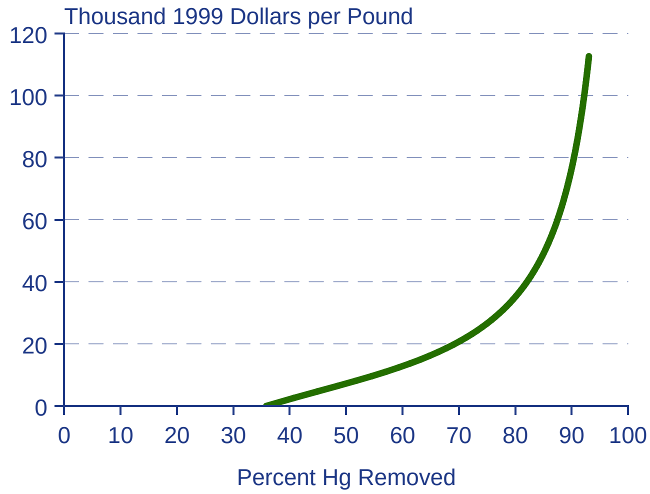
[25]This discussion only includes the cost of the activated carbon. Some capital investment and operations and maintenance costs will also be required but they are very small when compared with the cost of the activated carbon.

to be added to approximately 52 gigawatts of existing capacity in the Hg 5-ton case, 37 gigawatts more than in the reference case. By 2020, both NO_x and SO_2 emissions are projected to be below their reference case levels. In fact, SO_2 emissions are projected to be 1.7 million tons below the 8.95 million ton CAAA90 cap. In addition, although no cap on CO_2 emissions is assumed in the Hg 5-ton case, power sector CO_2 emissions are projected to be lower than in the reference case because of reduced coal use. In 2010, power sector CO_2 emissions are projected to total 664 million metric tons carbon equivalent in the Hg 5-ton case, 29 million metric tons (4 percent) lower than in the reference case.[26]

Both producer resource costs[27] and retail electricity prices are projected to be higher in the Hg 5-ton case as a result of expenditures made to reduce Hg emissions, higher natural gas prices resulting from increased demand, and Hg allowance costs (impacting prices and not resource costs) (Figure 7). Price increases brought about by efforts to reduce Hg emissions are expected to be larger than those in the NO_x 2008 and SO_2 2008 cases. In the Hg 5-ton case, electricity prices in 2010 are projected to be 3.9 percent higher than in the reference case, and in 2020 they are 2.6 percent higher. Total revenues from retail electricity sales are projected to be $8.4 billion higher than in the reference case in 2010 and $6.1 billion higher in 2020. Per pound of Hg emissions reduced, U.S. consumers are projected to pay $105,000 in 2010 and $76,300 in 2020, on average.

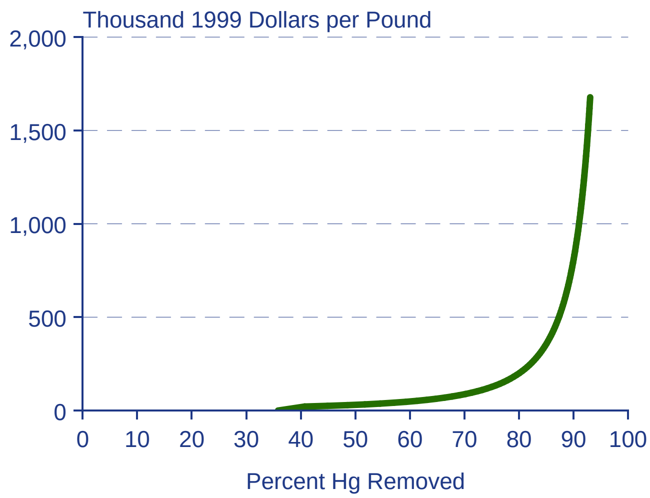
The Hg case with a less stringent emission cap demonstrates the sensitivity of the results to the level of reduction required. A 20-ton cap imposed in 2008 is projected to lead to much more modest changes from the reference case than does the Hg 5-ton case. The less stringent cap in the Hg 20-ton case leads to much lower Hg allowance costs and lower electricity price impacts than in the Hg 5-ton case. For example, the Hg allowance price in 2010

Figure 5. Average Cost of Activated Carbon per Pound of Hg Removed



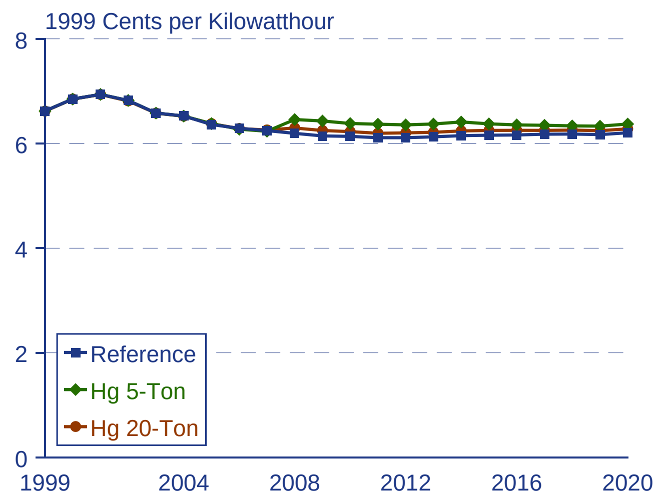
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Figure 6. Marginal Cost of Activated Carbon Per Pound of Hg Removed



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

Figure 7. Projected Electricity Prices in the Reference, Hg 5-Ton, and Hg 20-Ton Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE. D060801A, M2M9008.D060801A, and M2M6008.D060801A.

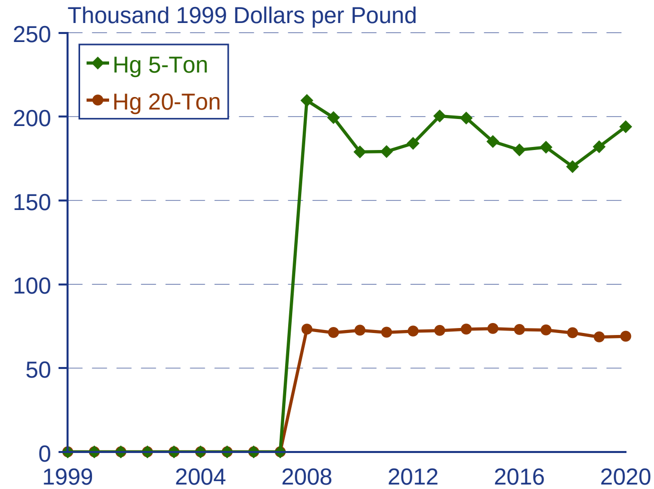
[26]Throughout this report carbon dioxide (CO_2) emissions are reported in terms of metric tons carbon equivalent. In other words, they are reported in carbon units, defined as the weight of the carbon content of carbon dioxide (i.e., the "C" in CO_2). To convert to metric tons of carbon dioxide multiply by 44/12 or 3.6667. For more discussion of this issue, see Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1999,* DOE/EIA-0573(99) (Washington, DC, October 2000).

[27]Resource costs include total fuel costs, operations and maintenance costs, and investment costs. They do not include allowance costs.

is projected to be $178,959 per pound in the Hg 5-ton case but only $72,519 per pound in the Hg 20-ton case (Figure 8). Similarly, while the price of electricity in the 5-ton case is projected to be 3.9 percent higher than in the reference case in 2010, the difference is only 1.5 percent in the 20-ton case.

The case with alternative assumptions about the cost and performance of Hg removal technologies demonstrates the sensitivity of the results to technological uncertainty (Table 9). Relative to the results in the Hg 5-ton case, the Hg 5-ton recycle case shows much lower cost and price impacts, assuming that activated carbon requirements can be reduced by 90 percent by recycling the carbon through the plant multiple times. It is impossible to say whether this level of recycling is feasible; however, the vast majority of the activated carbon injected in a once-through system does not make contact with Hg and could be used again. Thus, a fairly high level of recycling may be feasible. The price of an Hg

Figure 8. Projected Mercury Allowance Prices in Hg Cap Cases, 2000-2020



Source: National Energy Modeling System, runs M2M9008. D060801A and M2M6008.D060801A.

Table 9. Key Results for the Electricity Generation Sector in Hg Emission Cap Technology Cases, 2010 and 2020

Projection	1999	2010 Reference	2010 Hg 5-Ton Recycle	2010 Hg MACT 90%	2020 Reference	2020 Hg 5-Ton Recycle	2020 Hg MACT 90%
Emissions (Tons)							
Hg	43	46	5	8	45	5	8
SO_2 (Millions)	12.7	9.7	9.7	9.7	8.9	8.9	8.9
NO_x (Millions)	5.7	4.3	3.4	3.4	4.5	3.5	3.6
CO_2[a]	556	693	675	690	777	757	773
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	40,211	NA	NA	45,785	NA
SO_2 (per Ton)	207	187	118	114	241	109	145
NO_x (per Ton)	NA	4,391	3,140	4,162	5,037	4,682	4,798
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.22	6.19	6.21	6.30	6.21
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,188	2,266	2,366	2,249	2,336
Oil and Other	106	50	47	48	49	49	48
Natural Gas	593	1,085	1,174	1,115	1,813	1,907	1,842
Nuclear	734	725	725	725	613	613	617
Renewable	401	440	451	436	452	464	451
Total	3,728	4,597	4,585	4,590	5,294	5,281	5,294
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	12	27	15	25	27
SCR	0	93	96	94	93	98	95
SNCR	0	26	22	25	43	27	36
Hg Emission Controls							
Spray Cooling	0	0	148	169	0	156	174
Fabric Filter	0	0	238	187	0	245	192

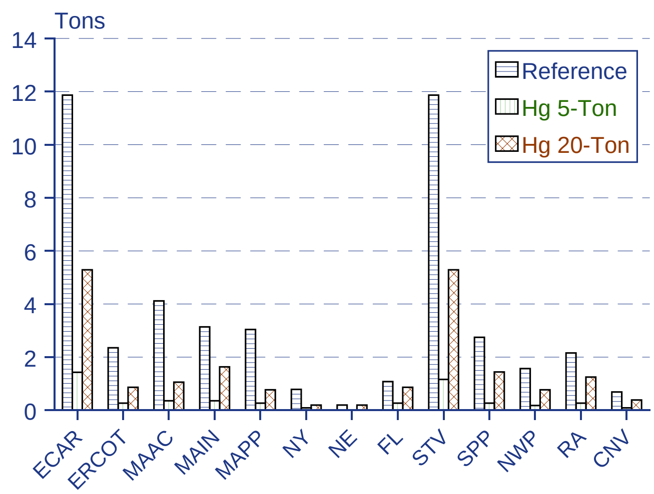
[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008A.D060801A, and M2M9008M.D060801A.

allowance in 2010 is expected to be $40,211 per pound in the Hg 5-ton recycle case, 78 percent lower than in the Hg 5-ton case. The price of electricity in 2010 is expected to be 6.2 cents per kilowatthour in the Hg 5-ton recycle case, 2.5 percent lower than in the Hg 5-ton case, and only 1.3 percent higher than in the reference case.

The activated carbon recycling technology is only one of several innovative Hg control technologies being studied, and the results in the Hg 5-ton recycle case are indicative of the potential impacts of general technological improvement. Because of the assumed improved performance for systems using a supplemental fabric filter combined with activated carbon injection, these systems are expected to become the dominant compliance strategy in this case. However, because of the early stage of development of these technologies it is not possible at this time to tell whether they will be able to contribute significantly to meeting a 2008 cap.

In the Hg 5-ton case, electric power plants in all regions are expected to reduce Hg emissions substantially (Figure 9). The percentage change relative to the reference case in 2010 varies from 76 percent to nearly 100 percent among the regions. In terms of tonnage changes, the greatest reductions are expected in the regions with the largest reference case emissions, potentially leading to much lower Hg concentrations in the areas of greatest concern. To meet the 5-ton cap, significant reductions in Hg emissions will be needed at nearly all plants. In the Hg 20-ton case, the burden of reducing Hg emissions is not projected to be spread as evenly. The less stringent cap allows plants in some regions to reduce their Hg emissions by more or less than those in other regions. For example, excluding regions that produce 1 ton of Hg or less, the percentage change relative to the reference case in 2010 varies from 47 percent to 75 percent among the regions in the Hg 20-ton case.

Figure 9. Projected Regional Hg Emissions in the Reference, Hg 5-Ton, and Hg 20-Ton Cases, 2010



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, and M2M6008.D060801A. See Figure 26 in Chapter 4 for a map of electricity supply regions.

One important question with respect to reducing Hg emissions is whether they will be controlled with a cap and trade program, as assumed in the cases discussed previously, or whether maximum achievable control technology (MACT) standards will be set for each plant type. Because Hg is a hazardous air pollutant (HAP), a MACT approach may have to be used (under the provisions of the Clean Air Act) rather than a cap and trade approach. While a cap and trade program should allow power suppliers the flexibility to reduce their emissions at the lowest possible cost, there is concern that the reduction in Hg emissions under such an approach would not be uniform across the country, and that some areas would continue to have high Hg emissions. In this analysis, the Hg MACT 90% case assumes that all plants will be required to reduce Hg emissions from the coal they use by 90 percent, without trading of allowances.

The results in the Hg MACT 90% case are generally similar to those in the Hg 5-ton case; however, there are several key differences. Requiring all plants to reduce the amount of Hg in the coal they use by 90 percent would not achieve a 90-percent reduction in overall Hg emissions relative to the 1997 level. In the reference case, the total amount of Hg in the coal used is expected to grow from approximately 73 tons in 1999 to 83 tons in 2020. As a result, without any shift in coal use, requiring each plant to remove 90 percent of the Hg in the coal it used would lead to total national Hg emissions of 8 tons. The use of a MACT approach does not provide operators of coal-fired electric power plants with an incentive to switch to lower Hg coals, because they will have to remove 90 percent of the Hg regardless of the coal used. In addition, unlike with a specified national cap, a MACT program would also allow Hg emissions to grow over time if coal use grew. The projected Hg emissions in 2020 in the Hg MACT 90% case are 8 tons, 3 tons over the emission target in the Hg 5-ton case.

The electricity price impacts in the Hg MACT 90% case are lower than those in the Hg 5-ton case, but the regional pattern of Hg emission reductions is similar (Figure 10). For example, in 2010 the projected electricity price in the Hg MACT 90% case is 6.19 cents per kilowatthour, 0.8 percent above the reference case price and 3.0 percent below the price in the Hg 5-ton case. The price impacts are lower in the MACT case because there is no Hg emission allowance market and allowance costs do not impact the dispatch decisions for coal-fired plants. In addition, as explained earlier in this chapter, the Hg MACT 90% case does not achieve the 5-ton cap. The regional projections for Hg emissions suggest that, if reductions of 90 percent or more are required, there is likely to be little opportunity for overcompliance in some areas and undercompliance in others, whether or not trading is allowed.

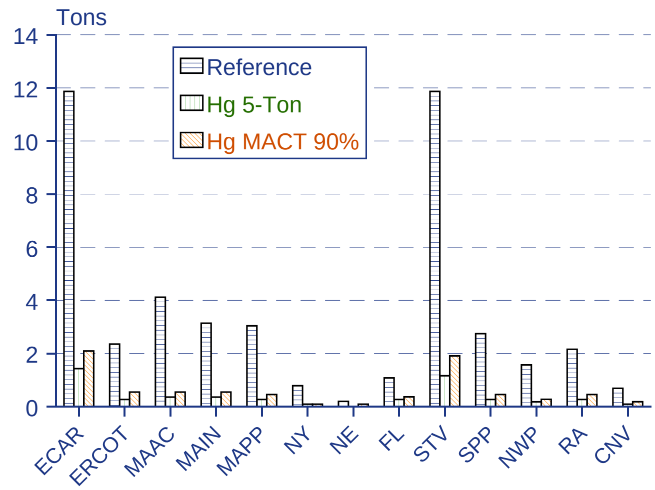
RPS Analysis

In the reference case, the use of renewable fuels to generate electricity is expected to increase slightly from 1999 to 2020. The Federal Government and some State governments have designed programs to spur renewable development, but they are not expected to lead to widespread use of renewables in the power sector. Although the cost and performance of new renewable generating technologies have improved, they still are not broadly competitive with fossil fuel technologies.

In the RPS 20% case, the 20-percent nonhydroelectric renewable fuel requirement is projected to lead to rapid development of new renewable technologies as it is phased in. With increased generation from nonhydroelectric renewables, generation from natural gas is projected to be lower than in the reference case (Figure 11 and Table 10). The key renewables for which increase are expected are biomass and wind (see Chapter 4).

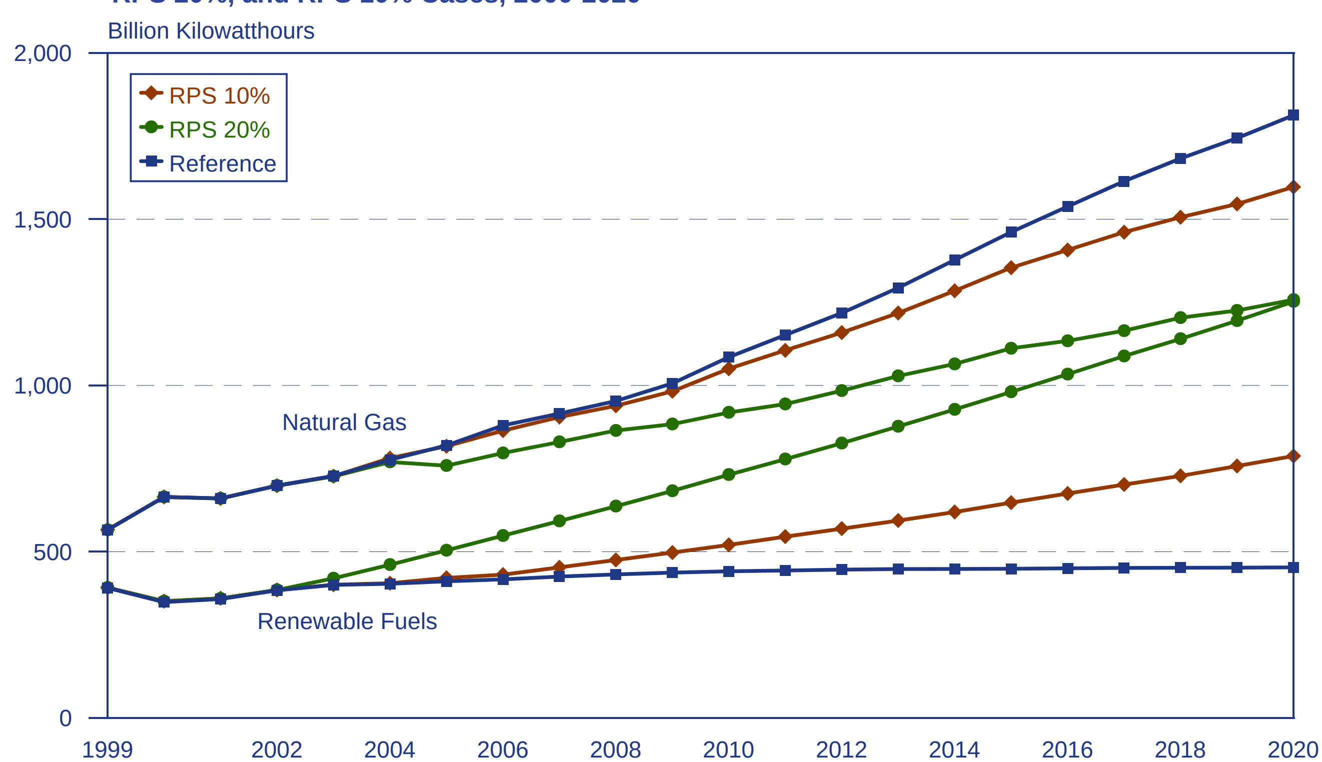
The development of the large amount of renewables that would be needed to satisfy the 20-percent RPS requirement has cost and price implications. Reaching the 20-percent target is expected to require increasing use of more expensive renewable options, and the renewable credit price (the subsidy needed to make nonhydroelectric renewables competitive) is expected to become quite high.[28] As the RPS is phased in, the renewable credit price is projected to increase to between 4 and 5 cents per kilowatthour from 2010 to 2020 (Figure 12).

Figure 10. Projected Regional Hg Emissions in the Reference, Hg 5-Ton, and Hg MACT 90% Cases, 2010



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, and M2M9008M.D060801A. See Figure 26 in Chapter 4 for a map of electricity supply regions.

Figure 11. Projected Electricity Generation from Natural Gas and Renewable Fuels in the Reference, RPS 20%, and RPS 10% Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

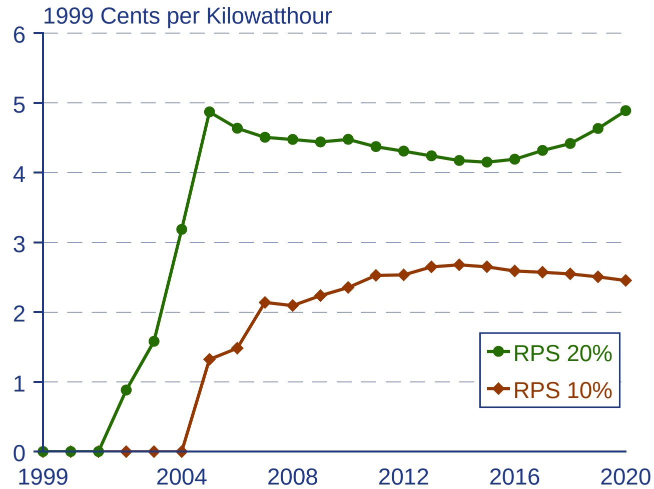
[28] Under an RPS, each seller of electricity is required to hold "credits" equivalent to the required percentage of sales from renewables. The credits, each representing 1 kilowatthour of generation from renewable fuels, can be sold by renewable generators to nonrenewable generators.

Natural gas prices are expected to decline as the use of renewable fuels increases. As a result, higher RPS credit prices are needed to keep renewable generating capacity competitive with new natural-gas-fired plants. Because each seller of electricity would only be required to hold credits equal to the required share of renewables (10 percent in 2010 and 20 percent in 2020), the impact on electricity prices is projected to be much smaller than the full price of the renewable credits. Lower natural gas prices due to reduced use by electricity generators also dampen the price increase. The price of electricity in the RPS case is expected to average 3 percent (about 0.2 cents) higher than in the reference case in 2010 and 4 percent higher in 2020.

The RPS 10% case shows the sensitivity of the projections to the required RPS share (Figure 13). The lower target for nonhydoelectric renewable generation reduces the need for power plant builders to develop more expensive renewable projects. As a result, electricity prices in the RPS 10% case are projected to be less than 1 percent higher than in the reference case.

The introduction of an RPS is projected to have only small impacts on SO_2, NO_x, and Hg emissions but a significant impact on CO_2 emissions, because the renewable plants added to meet the RPS would displace plants fueled with natural gas and, to a lesser extent, coal that would have been added without the RPS. Relative to the reference case, CO_2 emissions in 2020 are projected to be 56 million metric tons carbon equivalent (7 percent) lower in the RPS 10% case and 137 million metric tons

Figure 12. Projected Renewable Credit Prices in the RPS 20% and RPS 10% Cases, 2000-2020



Source: National Energy Modeling System, runs M2RPS20_X.D070601A and M2RPS20H_X.D070601A.

Table 10. Key Results for the Electricity Generation Sector in RPS Cases, 2010 and 2020

Projection	1999	2010			2020		
		Reference	RPS 20%	RPS 10%	Reference	RPS 20%	RPS 10%
Emissions (Tons)							
Hg	43	46	44	45	45	42	44
SO_2 (Millions)	12.7	9.7	9.7	9.7	8.9	8.9	8.9
NO_x (Millions)	5.7	4.3	4.2	4.3	4.5	4.1	4.4
CO_2[a]	556	693	638	677	777	640	721
Allowance Prices (1999 Dollars)							
Hg (per Pound)	NA	NA	NA	NA	NA	NA	NA
SO_2 (per Ton)	207	187	170	176	241	147	190
NO_x (per Ton)	NA	4,391	4,516	4,451	5,037	5,625	5,491
CO_2 (per Ton)[b]	NA	NA	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	6.33	6.17	6.21	6.47	6.22
Generation by Fuel (Billion Kilowatthours)							
Coal	1,893	2,297	2,157	2,250	2,366	2,090	2,246
Oil and Other	106	50	42	45	49	39	43
Natural Gas	593	1,085	919	1,051	1,813	1,258	1,597
Nuclear	734	725	725	725	613	613	613
Renewable	401	440	731	520	452	1,252	787
Total	3,728	4,597	4,573	4,591	5,294	5,252	5,286
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)							
Scrubbers[c]	0	7	6	6	15	10	10
SCR	0	93	97	94	93	100	94
SNCR	0	26	20	24	43	39	47

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

carbon equivalent (18 percent) lower in the RPS 20% case.

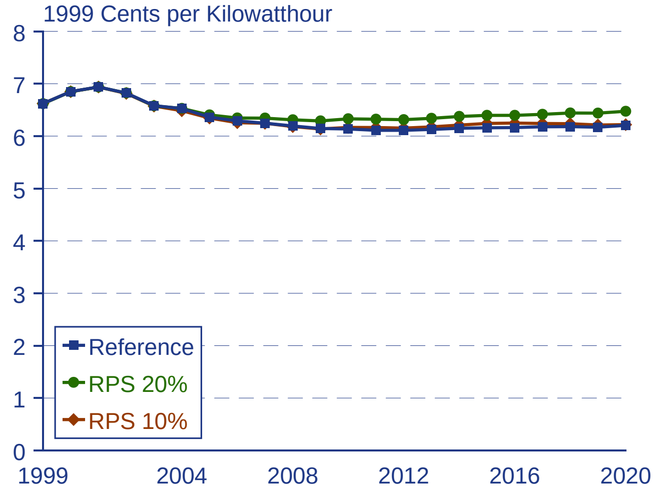
Analysis of CO_2 Caps

Unlike in the NO_x, SO_2, and Hg cases, the primary compliance strategy in the CO_2 1990-7% 2008 case is expected to be a major shift in the fuels used to produce electricity (Figure 14). To reduce CO_2 emissions to 7 percent below 1990 levels, power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewables. In addition, relative to the reference case, fewer nuclear plants are projected to be retired, consumers are expected to reduce their demand for electricity in response to higher electricity prices, and cogeneration capacity is expected to grow in response to higher grid-based electricity prices (Table 11).

Coal-fired generation in the CO_2 1990-7% 2008 case is projected to be 48 percent lower in 2010 and 56 percent lower in 2020 than in the reference case. Natural-gas-fired generation in the CO_2 1990-7% 2008 case is projected to be 61 percent higher than the reference case level in 2010 and 43 percent higher in 2020, and renewable generation is expected to be 27 percent higher in 2010 and 32 percent higher in 2020. Because 14 fewer gigawatts of nuclear capacity are expected to be retired in the CO_2 1990-7% 2008 case than in the reference case, nuclear generation is expected to be 3 percent higher in 2010 and 14 percent higher in 2020.

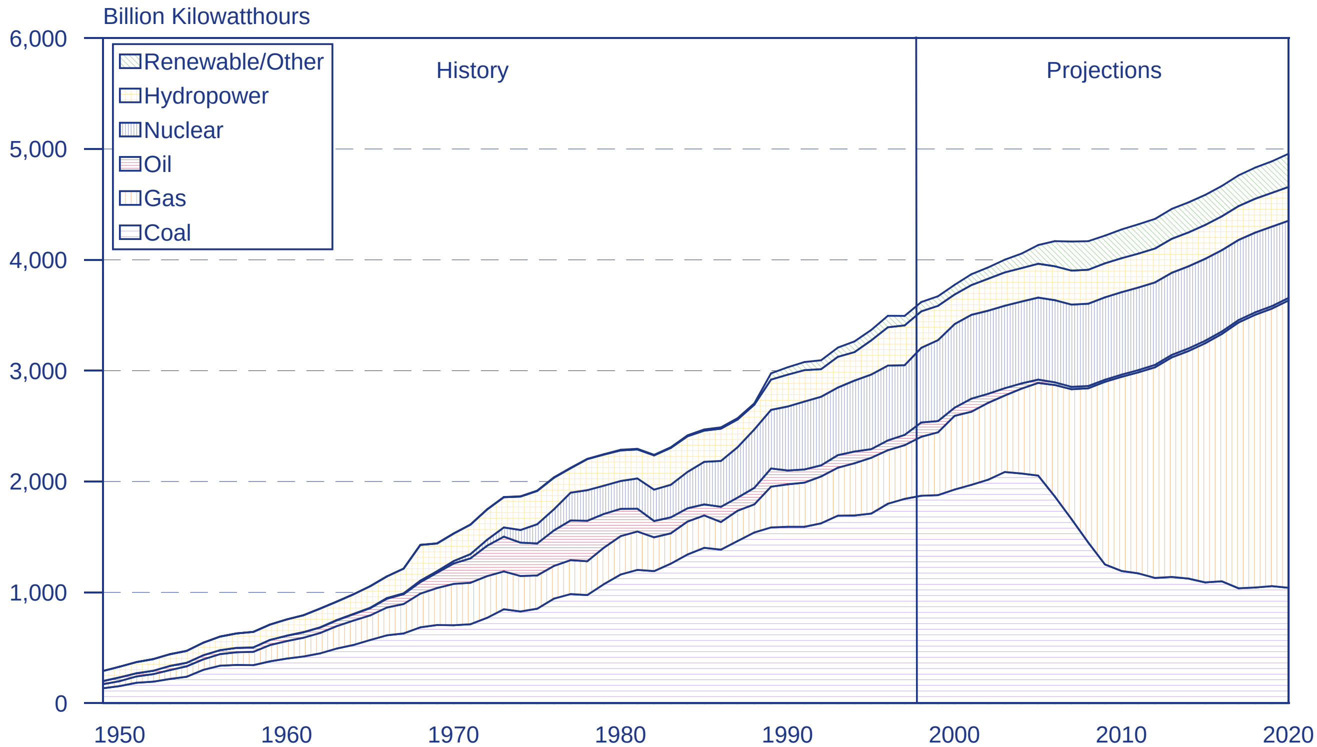
Consumers are expected to use less grid-based electricity in the CO_2 1990-7% 2008 case than in the reference case. In 2010, retail sales of electricity are expected to reach 3,803 billion kilowatthours in the CO_2 1990-7%

Figure 13. Projected Electricity Prices in the Reference, RPS 20%, and RPS 10% Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A.

Figure 14. Electricity Generation by Fuel, 1949-1999, and Projections for the CO_2 1990-7% 2008 Case, 2000-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run M2C7B08.D060801A.

2008 case, 344 billion kilowatthours (8 percent) less than in the reference case. End users are also expected to consume more cogenerated power for their own use. For example, in 2010, total generation from cogenerators is expected to reach 331 billion kilowatthours, 70 billion kilowatthours (27 percent) above the reference case projection.

Increased cogeneration in the CO_2 1990-7% 2008 case is not projected to lead to higher CO_2 emissions outside the electricity sector. All other things being the same, the reduced use of coal in the electricity sector would be expected to lead to lower coal prices and increased use of coal in sectors of the economy not facing a CO_2 emissions cap. However, more than 90 percent of the coal consumed in the United States is used in the electricity generation sector, and most of the other sectors of the economy do not employ technologies that can use coal. As a result, the higher electricity and natural gas prices caused by efforts to reduce CO_2 emissions in the electricity sector is expected to dampen overall energy use outside the electricity sector and reduce energy-associated CO_2 emissions in the other sectors.

The increased use of natural gas in the power sector and its impact on natural gas prices, together with CO_2 allowance prices, are projected to lead to much higher electricity prices in the CO_2 1990-7% 2008 case than in the reference case. The wellhead price of natural gas is projected to reach $3.36 per thousand cubic feet in 2010 and $3.74 in 2020 in the CO_2 1990-7% 2008 case, compared with $2.87 and $3.22, respectively, in the reference case. CO_2 allowance prices in 2010 and 2020 are projected to be $157 and $151 per metric ton carbon equivalent, respectively, in the CO_2 cap case. It should be noted, however, that the projected NO_x and SO_2 allowance prices in the CO_2 1990-7% 2008 case are dramatically lower than those in the reference case, because efforts to reduce CO_2 emissions also reduce the need for investments to mitigate NO_x and SO_2 emissions. NO_x and SO_2 emissions in the CO_2 1990-7% 2008 case are projected to be 52 and 18 percent lower, respectively, than the reference case levels in 2020. In addition, efforts to reduce CO_2 lead to a 24-ton (53 percent) reduction in Hg emissions from the reference case level by 2020.

Table 11. Key Results for the Electricity Generation Sector in the CO_2 1990-7% 2008 Emission Cap Case, 2010 and 2020

Projection	1999	2010		2020	
		Reference	CO_2 1990-7% 2008	Reference	CO_2 1990-7% 2008
Emissions (Tons)					
Hg	43	46	24	45	21
SO_2 (Millions)	12.7	9.7	8.2	8.9	7.3
NO_x (Millions)	5.7	4.3	2.4	4.5	2.2
CO_2[a]	556	693	436	777	445
Allowance Prices (1999 Dollars)					
Hg (per Pound)	NA	NA	NA	NA	NA
SO_2 (per Ton)	207	187	0	241	0
NO_x (per Ton)	NA	4,391	0	5,037	0
CO_2 (per Ton)[b]	NA	NA	157	NA	151
Electricity Price (1999 Cents per Kilowatthour)	6.66	6.14	8.81	6.21	8.56
Generation by Fuel (Billion Kilowatthours)					
Coal	1,893	2,297	1,193	2,366	1,042
Oil and Other	106	50	32	49	37
Natural Gas	593	1,085	1,752	1,813	2,592
Nuclear	734	725	744	613	696
Renewable	401	440	558	452	595
Total	3,728	4,597	4,280	5,294	4,963
Emissions Controls (Cumulative Gigawatts of Generating Capability with Controls Added)					
Scrubbers[c]	0	7	0	15	0
SCR	0	93	77	93	77
SNCR	0	26	36	43	37

[a]Million metric tons carbon equivalent.
[b]1999 dollars per metric ton carbon equivalent.
[c]An additional 2.7 gigawatts of retrofits are planned during 2000-2002.
NA = not applicable.
Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A.

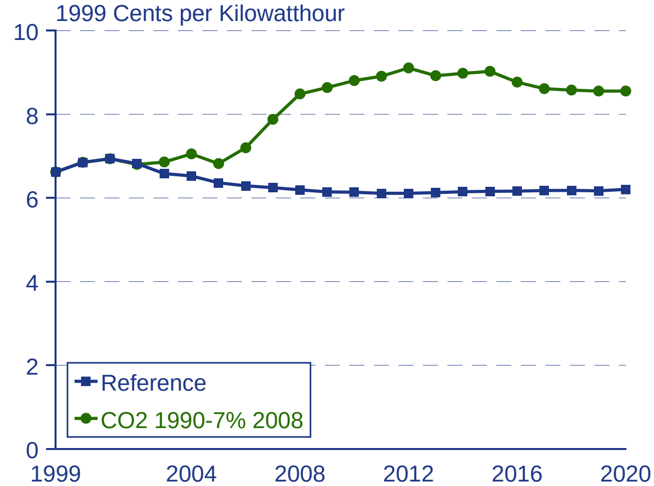
Electricity prices are projected to be much higher in the CO_2 1990-7% 2008 case than in the reference case—43 percent higher in 2010 and 38 percent higher in 2020 (Figure 15). As a result, annual household electricity bills are projected to be $218 (23 percent) higher in 2010 and $173 (17 percent) higher in 2020, and the Nation's total electricity bill is projected to be $80 billion higher in 2010 and $63 billion higher in 2020 than in the reference case, despite expected reductions in consumer electricity use (8 percent lower in 2010 than projected in the reference case and 12 percent lower in 2020).

Analysis of Integrated Cases

Because actions taken by electricity producers to reduce NO_x, SO_2, CO_2, or Hg emissions—or to develop new renewable generators when an RPS is imposed—will affect the actions needed to meet the other emission caps or the RPS requirement, it is expected that integrated compliance decisions will be different from those targeted to any single requirement. In this analysis, six integrated cases incorporate different combinations of power sector emission caps on NO_x, SO_2, Hg, and CO_2, with and without an RPS (see Table 1 in Chapter 2), and three integrated sensitivity cases examine the effects of alternative assumptions on the results of the integrated cases (see Table 3 in Chapter 2). The key result in all the integrated cases is that when a cap on power sector CO_2 emissions is imposed, efforts to meet it also reduce the other emissions. The price and cost impacts in each of the integrated cases with a CO_2 cap are dominated by efforts to reduce CO_2 emissions (Table 12).

It should be noted, however, that when emission caps on NO_x, SO_2, CO_2, and Hg are assumed in various combinations, with and without an RPS, there are complex interactions among the compliance strategies and the resulting prices of emission allowances and electricity prices. The interactions can cause the impacts on resource costs and the impacts on electricity prices to move in opposite directions. For example, although resource costs are projected to be higher when caps are placed on all four emissions than when they are placed only on NO_x, SO_2, and CO_2, electricity prices are projected to be slightly lower. This occurs because the addition of an Hg cap raises the cost of continuing to operate existing coal-fired plants, leading to a reduction in the CO_2 allowance price that would be required to encourage power suppliers to retire coal-fired power plants and replace them with natural-gas-fired plants. Because the CO_2 allowance price would be included in the operating costs for all generating plants that use fossil fuels, a lower CO_2 allowance price would reduce the revenues of power suppliers in the cases with four emissions caps by lowering the costs of operating fossil plants and, thus, would lead to lower electricity prices.

Figure 15. Projected Electricity Prices in the Reference and CO_2 1990-7% 2008 Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE. D060801A and M2C7B08.D060801A.

Similarly, when an RPS is assumed to be combined with caps on NO_x, SO_2, CO_2, and Hg emissions, resource costs for generators complying with the caps are projected to be higher than when the RPS is not included. However, while electricity prices are projected to be well above reference case levels when NO_x, SO_2, CO_2, and Hg emissions are capped either with or without an RPS, they are projected to be lower in the long term when the RPS is included,[29] because increased dependence on renewables rather than natural gas would lead to lower prices for natural gas and for CO_2 allowances, offsetting the effects of the higher costs of renewable fuels on consumer electricity prices. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as "producer surplus") to consumers (increasing "consumer surplus") even though the producers' resource costs are higher.

Integrated Cases Reducing CO_2 Emissions to 1990 Levels

When power sector CO_2 emissions are assumed to be capped at the 1990 level in combination with various other emission caps, with or without an RPS, the key compliance strategy is projected to be a shift from coal to natural gas and, to a lesser extent, renewables (Figure 16). The results in the integrated cases with a CO_2 1990 cap are similar to those in the CO_2 1990-7% 2008 case but with smaller impacts because the CO_2 cap is less stringent. The role of renewables is especially important in cases that include an RPS. In addition, fewer nuclear

[29] In the early years of the forecast, electricity prices are projected to be higher in the case that combines an RPS with caps on NO_x, SO_2, CO_2, and Hg emissions than in the case that includes only the four emission caps.

Table 12. Key Results for the Electricity Generation Sector in Integrated Cases, 2010 and 2020

Analysis Case	Generation by Fuel (Billion Kilowatthours)			Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	Allowance Prices (1999 Dollars)				Electricity Price (1999 Cents per Kilowatt-hour)	Electricity Sales (Billion Kilowatt-hours)	Annual Household Electricity Bill (1999 Dollars)	Total Electricity Revenue (Billion 1999 Dollars)
	Coal	Natural Gas	Renewable Fuels		CO_2[a] (per Ton)	NO_x (per Ton)	SO_2 (per Ton)	Hg (per Pound)				
2010												
Reference	2,297	1,085	436	2.87	NA	4,391	187	NA	6.14	4,147	944	255
Cases with CO_2 Emissions Capped at 1990 Level												
Integrated NO_X, SO_2, CO_2 1990	1,432	1,585	551	3.24	112	0	431	NA	8.13	3,873	1,108	315
Integrated NO_X, SO_2, $CO_2$1990, Hg	1,333	1,734	523	3.40	84	0	1	221,624	7.92	3,896	1,090	308
Integrated All CO_2 1990	1,471	1,344	762	2.97	84	0	3	216,210	8.01	3,882	1,097	311
Cases with CO_2 Emissions Capped at 1990-7% Level												
Integrated NO_X, SO_2, CO_2 1990-7%	1,189	1,780	551	3.50	142	0	246	NA	8.62	3,830	1,152	330
Integrated NO_X, SO_2, $CO_2$1990-7%, Hg	1,113	1,889	542	3.66	120	0	0	147,925	8.42	3,851	1,136	324
Integrated All CO_2 1990-7%	1,268	1,512	745	3.13	124	0	2	171,250	8.59	3,830	1,147	329
Integrated Sensitivity Cases												
Integrated Moderate Targets	1,539	1,456	572	3.09	111	0	43	55,507	8.18	3,870	1,109	316
Integrated Cost of Service	1,046	2,025	554	3.96	117	0	0	154,014	7.68	3,956	1,069	304
Integrated High Gas Price	1,124	1,838	553	4.08	125	0	0	152,337	8.60	3,838	1,152	330
2020												
Reference	2,366	1,813	448	3.22	NA	5,037	241	NA	6.21	4,788	1,005	297
Cases with CO_2 Emissions Capped at 1990 Level												
Integrated NO_X, SO_2, CO_2 1990	1,136	2,571	572	3.69	143	0	436	NA	8.41	4,291	1,177	361
Integrated NO_X, SO_2, $CO_2$1990, Hg	1,124	2,584	561	3.72	135	0	2	148,278	8.36	4,309	1,172	360
Integrated All CO_2 1990	1,390	1,784	1,178	3.09	71	1,304	150	203,663	7.82	4,354	1,127	340
Cases with CO_2 Emissions Capped at 1990-7% Level												
Integrated NO_X, SO_2, CO_2 1990-7%	1,013	2,605	611	3.80	154	0	259	NA	8.63	4,218	1,185	364
Integrated NO_X, SO_2, $CO_2$1990-7%, Hg	1,032	2,608	602	3.74	150	0	1	109,636	8.55	4,257	1,182	364
Integrated All CO_2 1990-7%	1,235	1,909	1,176	3.31	90	1,118	0	168,463	7.98	4,313	1,142	344
Integrated Sensitivity Cases												
Integrated Moderate Targets	1,413	2,138	755	3.74	119	0	30	45,114	8.19	4,318	1,158	354
Integrated Cost of Service	894	2,719	705	4.15	162	0	0	121,781	7.86	4,453	1,126	350
Integrated High Gas Price	1,082	2,098	735	5.05	169	0	2	171,790	9.27	4,188	1,237	388

[a]1999 dollars per metric ton carbon equivalent.

NA = not applicable.

Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, M2P7B08R_X.D070601A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A.

plants are expected to be retired than in the cases without CO_2 caps, and consumers are expected to reduce electricity consumption in response to higher electricity prices. As in the CO_2 1990-7% 2008 case, reduced electricity usage by consumers and increased cogeneration also play a role.

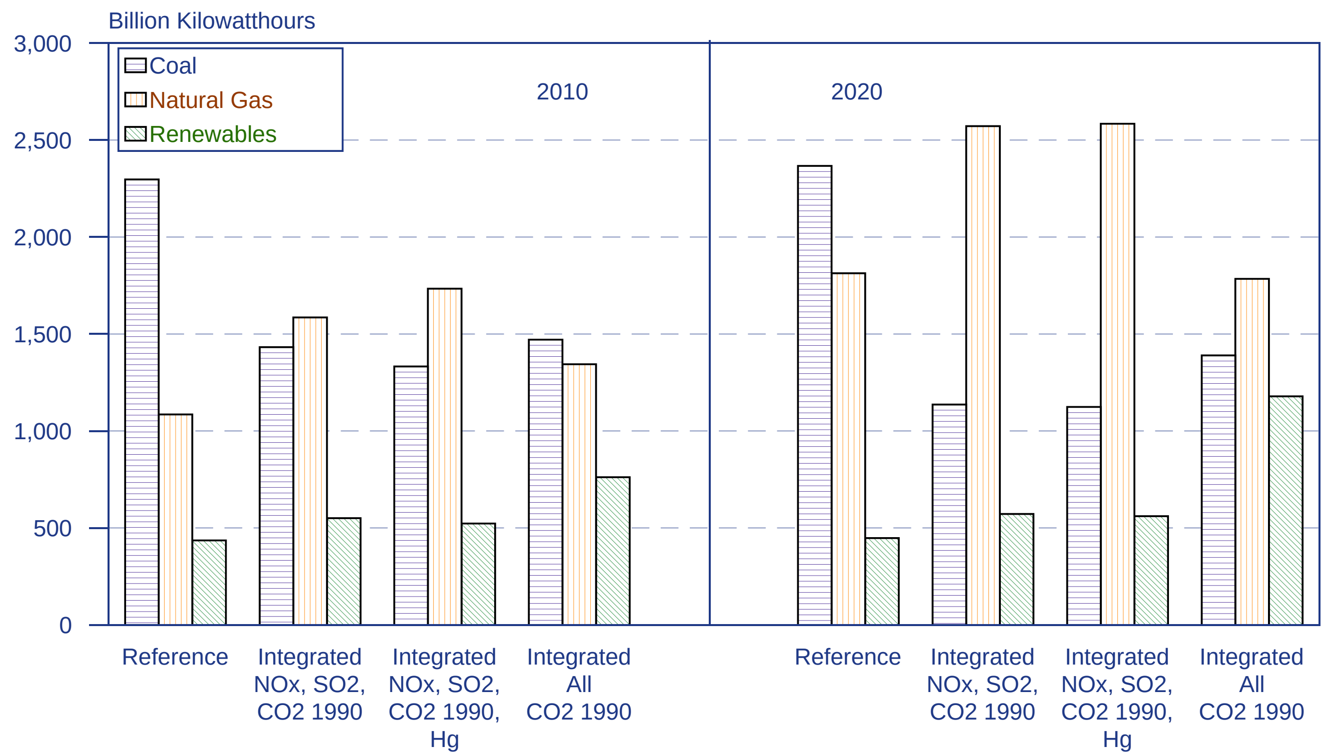
Relative to the reference case, coal-fired generation in 2010 is expected to be between 38 and 42 percent lower in the integrated NO_x, SO_2, CO_2 1990 and integrated NO_x, SO_2, CO_2 1990, Hg cases. The inclusion of an RPS, as in the integrated all CO_2 1990 case, leads to higher projections for coal-fired electricity generation than would otherwise be expected in a case with a CO_2 cap. For example, in 2010, coal-fired generation in the integrated all CO_2 1990 case is projected to be 1,471 billion kilowatthours, 10.4 percent above the level projected in the integrated NO_x, SO_2, CO_2 1990, Hg case. Under an RPS, the forced penetration of renewables that produce no CO_2 eases the pressure on power suppliers to reduce their use of coal to comply with the CO_2 cap.

The situation for natural-gas-fired generation is projected to be the opposite of that for coal—reducing power sector CO_2 emissions means increasing natural gas use. Relative to the reference case, natural-gas-fired generation in 2010 is projected to be 46 percent higher in the integrated NO_x, SO_2, CO_2 1990 case and 60 percent higher in the integrated NO_x, SO_2, CO_2 1990, Hg case. In the integrated all CO_2 1990 case, the role of increased gas use in reducing CO_2 emissions is dampened somewhat by the penetration of renewables. The renewables added to comply with the RPS reduce the need for power suppliers to add natural gas plants to displace coal plants.

Electricity generation from renewable fuels is also expected to be higher in integrated cases with a CO_2 emission cap. For example, in the integrated NO_x, SO_2, CO_2 1990 case, renewable generation in 2010 is projected to reach 551 billion kilowatthours, 115 billion kilowatthours (26 percent) higher than in the reference case. The penetration of renewables is sensitive to both the price of natural gas and the price of CO_2 allowances. Although wellhead natural gas prices are projected to be higher in the integrated NO_x, SO_2, CO_2 1990, Hg case than in the integrated NO_x, SO_2, CO_2 1990 case—which would tend to make renewables more attractive—the CO_2 allowance price is projected to be lower, leading to lower renewable penetration.

The increased dependence on natural gas and renewables to reduce power sector CO_2 emissions is expected to have implications for emissions allowance prices, electricity prices, and generating costs. In cases that combine a CO_2 emission cap with NO_x, SO_2, and/or Hg emission caps, the industry's efforts to comply with the CO_2 cap lead to much lower allowance prices for NO_x, SO_2, and Hg, because the reduction in coal use lessens the need for investments to reduce NO_x, SO_2, and Hg emissions. For example, in the integrated NO_x, SO_2, CO_2

Figure 16. Projected Electricity Generation from Coal, Natural Gas, and Renewable Fuels in the Reference and Integrated CO_2 1990 Cases, 2010 and 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, and M2P9008R_X.D070601A.

1990, Hg case, the SO_2 allowance price in 2010 is projected to be nearly zero, as compared with $794 per ton in the SO_2 2008 case, which assumes the same cap on SO_2 emissions. Also, as shown in the CO_2 1990-7% 2008 case, controlling power sector CO_2 emissions alone is expected to lead to Hg emissions in 2010 that are 53 percent lower than in the reference case.

A similar change is projected for NO_x allowance prices. In the later years of the projections in the integrated NO_x, SO_2, CO_2 1990, Hg case, the NO_x allowance price is well below the price in the NO_x 2008 case, because some of the control equipment that would be added to reduce NO_x emissions is unnecessary when coal use is reduced. When an RPS is combined with caps on NO_x, SO_2, and Hg, there is less pressure to reduce coal use for electricity generation. As a result, the projected prices of NO_x, SO_2, and Hg allowances are higher in the integrated all CO_2 1990 case than in the integrated NO_x, SO_2, CO_2 1990, Hg case.

In the three integrated cases that assume a CO_2 emissions cap at the 1990 level, the expected shift to natural gas and renewables for power generation, combined with investments made to reduce NO_x, SO_2, and Hg emissions and the costs of holding emissions allowances is projected to lead to higher electricity prices and production costs. The price of electricity in 2010 is projected to range between 7.92 and 8.13 cents per kilowatthour in the three cases—between 29 percent and 32 percent higher than projected in the reference case. Prices are slightly lower in the integrated NO_x, SO_2, CO_2 1990, Hg case than in the integrated NO_x, SO_2, CO_2 1990 case, because the cap on Hg emissions makes existing coal-fired plants less economically attractive and reduces the CO_2 allowance price required to stimulate a shift from coal to natural gas. Total revenues for the power generation industry in 2010 in the three integrated CO_2 1990 cap cases are projected to be between $54 billion and $60 billion over the reference case level. For the average household this translates into an annual electricity bill that is between $145 and $163 higher than projected in the reference case in 2010.

The addition of the RPS to caps on NO_x, SO_2, CO_2, and Hg emissions is projected to increase the resource costs of compliance faced by power suppliers from what they would be without the RPS requirement. However, the electricity price projections in the integrated all CO_2 1990 case, which includes a 20-percent RPS requirement, are lower than those in the integrated NO_x, SO_2, CO_2 1990, Hg case in later years, because the price impact of higher cost renewables is offset by lower gas prices and lower CO_2 allowance prices. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as “producer surplus”) to consumers (increasing “consumer surplus”) even though the producers’ resource costs are higher. In other words, increased reliance on renewables in the integrated all CO_2 1990 case leads to smaller increases in natural gas prices and CO_2 allowance prices. Although electricity prices are similar in the integrated cases with and without the RPS, the resource costs are higher in the case with the RPS (Figure 17).

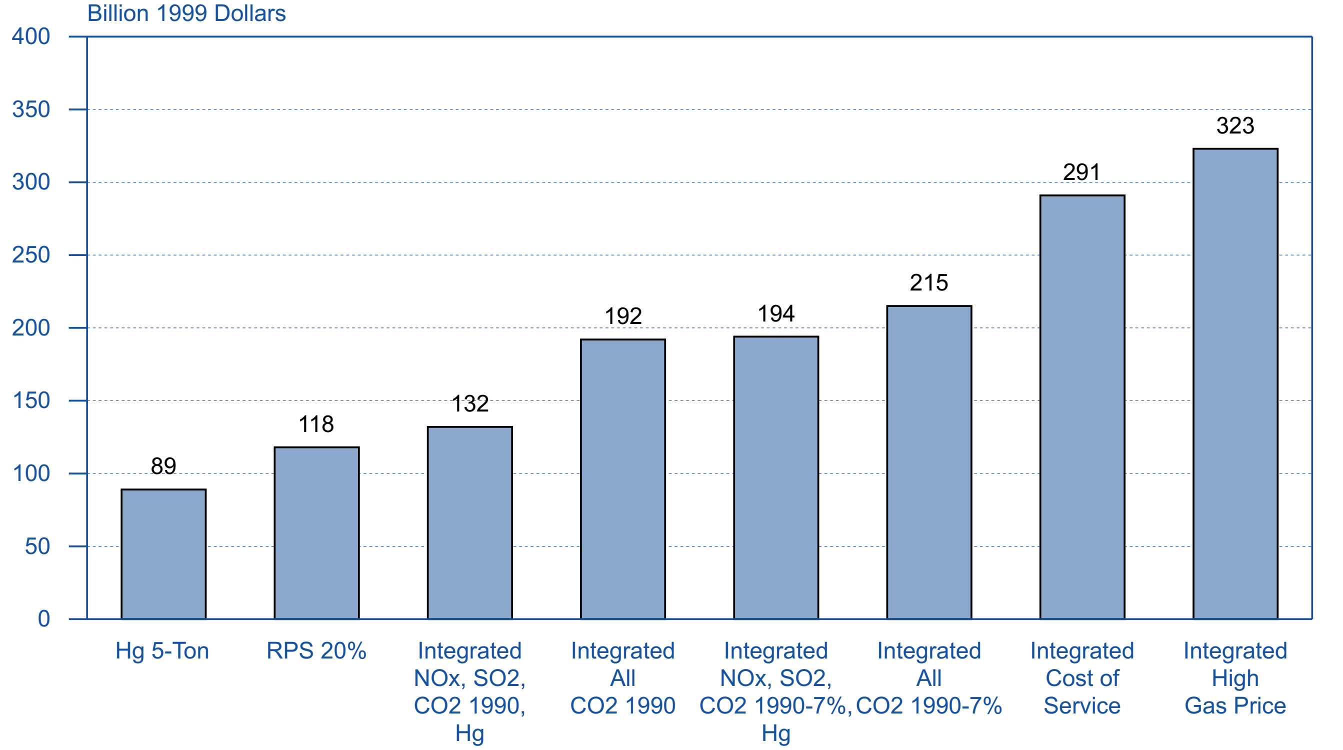
Because the decisions made to control one emission—particularly, decisions made to reduce CO_2 emissions—affect the other emissions, the timing or sequencing of the control programs could be important. When facing requirements to reduce multiple emissions, power suppliers will attempt to choose a strategy that allows them to meet all the requirements most economically. They will attempt to take account of the sequencing and timing (provided that they are known) of the various emission reduction requirements. As shown in this analysis, if the emissions reduction programs for NO_x, SO_2, Hg, and CO_2 were on the same timetable, power suppliers would be expected to retire a large number of existing coal-fired plants to reduce CO_2 emissions and forgo installing emissions control equipment to reduce NO_x, SO_2, and Hg emissions. If, on the other hand, they were required to reduce NO_x, SO_2, and Hg emissions before reducing CO_2 emissions, larger investments in NO_x, SO_2, and Hg emissions control equipment might make economic sense.

Integrated Cases Reducing CO_2 Emissions to 7 Percent Below the 1990 Level

The results in the integrated cases that cap power sector CO_2 emissions at 7 percent below the 1990 level essentially parallel those in the cases that cap them at the 1990 level. As in those cases, the key compliance strategy is a shift from coal to natural gas and renewables combined with fewer nuclear plant retirements and reduced consumer electricity use. Relative to the cases with power sector emissions capped at the 1990 level, the shift out of coal, reliance on renewables, CO_2 allowance prices, and electricity prices all are higher in the cases with CO_2 emissions capped at the 1990-7% level.

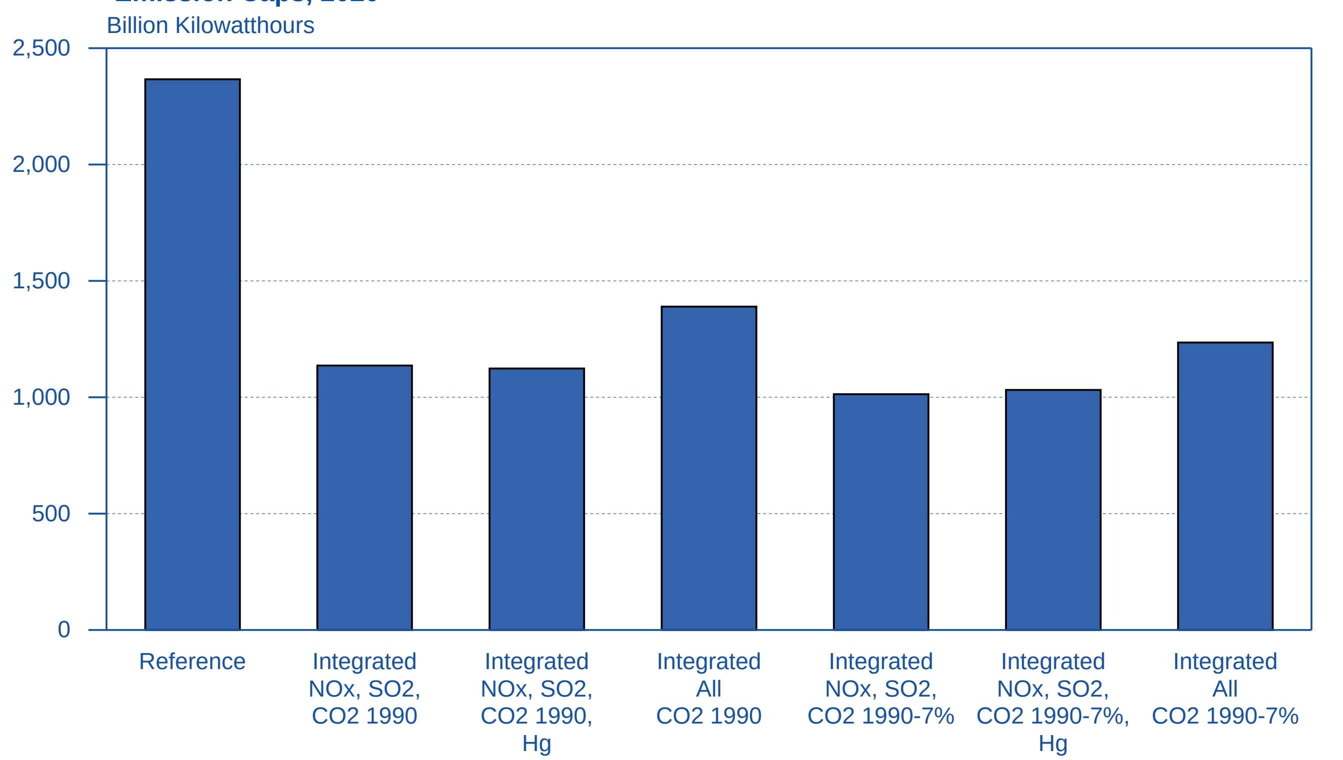
Figure 18 compares the projected coal generation in 2020 in the cases with CO_2 emissions capped at the 1990 level with those capped at the 1990-7% level. Among the comparable cases the coal generation in 2020 is between 8 percent and 11 percent lower in the cases with the more stringent CO_2 cap. Note that projected coal generation is higher in the cases that include an RPS requirement—the integrated all CO_2 1990 and integrated all CO_2 1990-7% cases. The penetration of carbon-free renewables stimulated by the RPS lowers the need to reduce coal use to meet the CO_2 emission caps. Conversely, renewable generation is significantly higher in the case with a more stringent CO_2 cap and no RPS (Figure 19). In the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, total renewable generation reaches 16.1 percent of sales in

Figure 17. Cumulative Resource Costs for Electricity Production, 2001-2020: Differences from Reference Case Projection in Selected Cases



Source: National Energy Modeling System, runs M2BASE.D080401A, M2M9008.D080401A, M2P9008.D080401A, M2RPS20.D080401A, M2P9008R.D080401A, M2P7B08.D080401A, M2P7B08R.D080401A, M2P7B08L.D080401A, and M2P7B08C.D080401A.

Figure 18. Projected Coal-Fired Electricity Generation in the Reference Case and Integrated Cases with CO_2 Emission Caps, 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A.

2020, while nonhydroelectric renewable generation (the facilities that qualify for the RPS) reaches 6.6 percent of sales. Although this amount is still far below the 20-percent level required in the cases with an RPS, it illustrates that meeting a power sector CO_2 cap set at 7 percent below the 1990 level could stimulate additional renewable development.

CO_2 allowance prices, natural gas prices, and electricity prices all are projected to be higher in the cases with a CO_2 emission cap of 7 percent below the 1990 level than they are in the cases with the less stringent CO_2 cap. For example, in 2010 CO_2 allowance prices are projected to be $120 per metric ton carbon equivalent in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, $36 (43 percent) above the level in the comparable case with the CO_2 cap set at the 1990 level (see Table 12). At the same time, electricity prices are projected to be 8.42 cents per kilowatthour (6 percent) above the level in the comparable case with the CO_2 cap set at the 1990 level and 2.28 cents per kilowatthour (37 percent) above the reference case level (Figure 20).

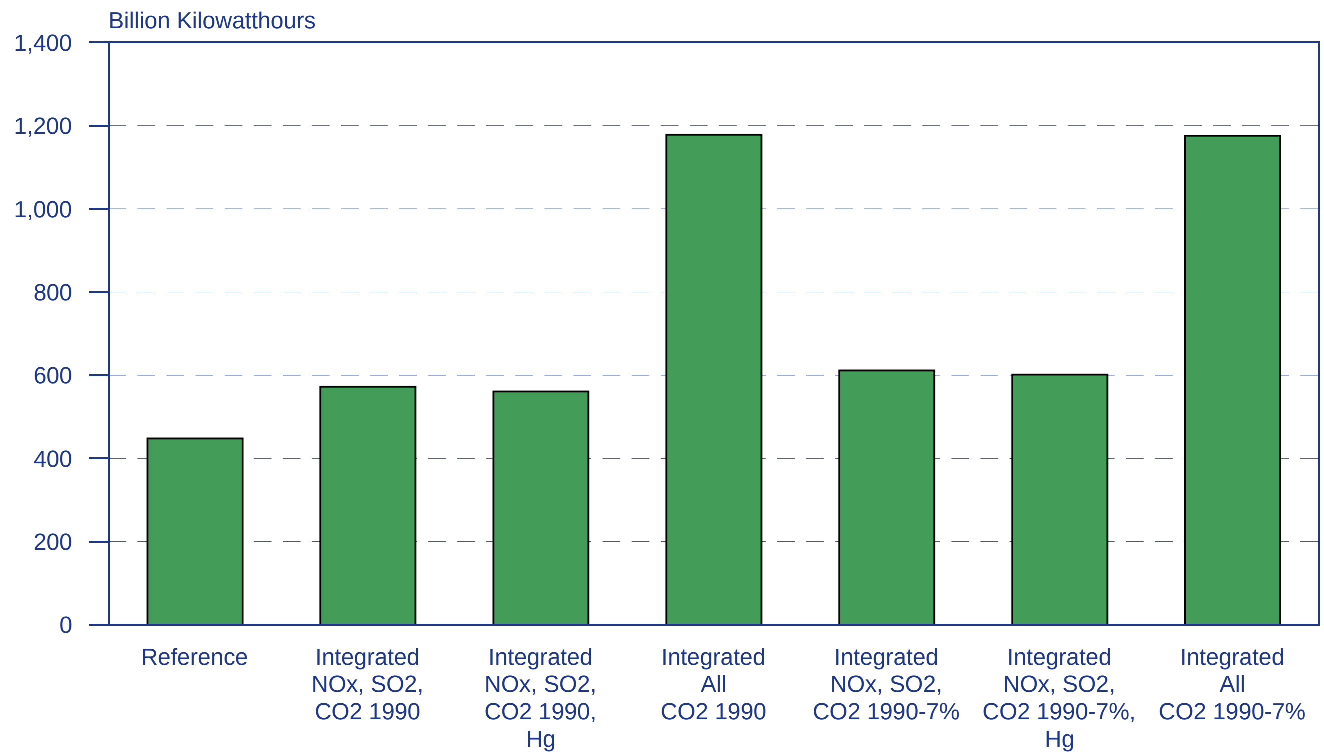
The addition of the RPS to caps on NO_x, SO_2, CO_2, and Hg emissions is projected to increase the resource costs of compliance faced by power suppliers by $21 billion over the 2000 to 2020 time period from what it would be without the RPS requirement. However, as with CO_2 1990 cap cases, electricity prices in the later years of the integrated NO_x, SO_2, CO_2 1990-7%, Hg case are higher than in the integrated case with an RPS requirement. Forcing in renewables with the RPS leads to lower natural gas prices and, in turn, lower electricity prices. The average price of natural gas delivered to electricity producers in 2020 in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case is $4.49 per thousand cubic feet, $0.56 (14 percent) higher than in the comparable case with an RPS. And with increased investment in more expensive renewable generators, resource costs are higher in the integrated case with an RPS. Essentially, the introduction of the RPS shifts revenues from suppliers (reducing what economists refer to as “producer surplus”) to consumers (increasing “consumer surplus”) even though the producers’ resource costs are higher.

Integrated Sensitivity Cases

Many factors influence the results of the model projections presented in this analysis. Sensitivity cases are employed to illustrate the potential impacts of three key areas of importance—the levels of the emission caps chosen, the pricing of electricity in regulated regions, and natural gas prices.

In the integrated moderate targets case, the caps on NO_x, SO_2, CO_2, and Hg emissions and the RPS are all less stringent than in the integrated all CO_2 1990-7% case

Figure 19. Projected Electricity Generation from Renewable Fuels in the Reference Case and Integrated Cases with CO_2 Emission Caps, 2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A.

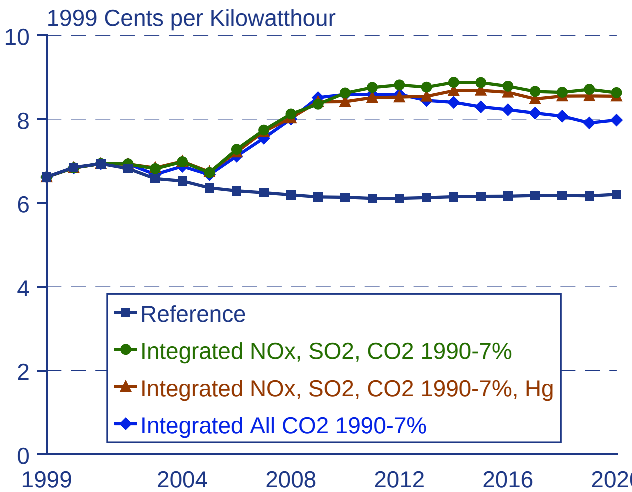
(see Tables 2 and 4 in Chapter 2). The reduced stringency of this case leads to lower allowance and electricity prices, especially in the early years of the projections (Figure 21). For example, in 2010 CO_2 allowance prices are projected to be $111 per metric ton carbon equivalent in the integrated moderate targets case, $13 (10 percent) lower than in the comparable integrated all CO_2 1990-7% case. Electricity prices are also much lower, reaching only 8.18 cents per kilowatthour in 2010, compared with 8.59 cents per kilowatthour in the integrated all CO_2 1990-7% case. By 2020 the electricity prices projected in the two cases are similar, because the more stringent RPS in the integrated all CO_2 1990-7% case leads to lower natural gas prices in 2020. As in other cases with a CO_2 cap, the key compliance strategy for electricity producers is expected to be a shift from coal to natural gas and renewables.

The integrated cost of service case assumes that emission allowances in regions of the country that remain under regulated pricing will be treated as having zero cost and not reflected in electricity prices (see Chapter 2 for a description of regional pricing). This case does not include an RPS. The resulting projections show lower electricity prices in regulated regions but higher prices in competitive regions than are projected in the comparable integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Resource costs are higher in the sensitivity case, because consumers are not expected to reduce their electricity usage by as much, and power suppliers are therefore projected to take additional actions to reduce emissions. Relative to the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, demand for electricity is projected to be higher, natural gas prices are higher, and reliance on renewables is greater. Electricity prices in the integrated cost of service case in 2010 are projected to be 25 percent higher than in the reference case but 9 percent lower than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. Total resource costs are projected to be 4 percent higher than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case.

In the integrated high gas price case (with no RPS), it is assumed that improvements in the technologies associated with the discovery, development, and delivery of natural gas are not as robust as in the reference and other cases. The change in assumptions in this case is not meant to represent an expectation but, rather, to demonstrate the sensitivity of the results to higher natural gas prices. While the main compliance strategy remains a switch from coal to natural gas and renewables, electricity prices and resource costs are projected to be higher and reliance on renewables greater. In addition, because of higher natural gas and electricity prices, consumers are projected to play a larger role in reducing emissions by lowering their use of natural gas and electricity.

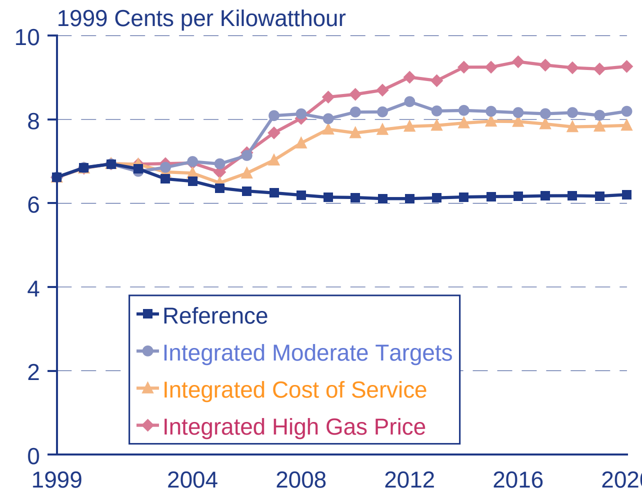
For example, the price of electricity in 2020 in the integrated high gas price case is projected to be 9.27 cents per kilowatthour—49 percent higher than in the reference case and 8 percent higher than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case, which incorporates the same natural gas technology assumptions as the reference case. By 2020, the share of generation coming from all renewables is projected to be 18 percent in the integrated high gas price, 9 percentage points higher than projected in the reference case and 4 percentage points higher than in the integrated NO_x, SO_2, CO_2 1990-7%, Hg case. On the other hand, consumers are projected to use 13 percent less electricity in 2020 in the integrated high gas price case than in the reference case.

Figure 20. Projected Electricity Prices in the Reference Case and Integrated Cases with 1990-7% CO_2 Emission Caps, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A.

Figure 21. Projected Electricity Prices in the Reference Case and Integrated Sensitivity Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A.

Summary and Uncertainties

In cases without a CO_2 emission cap, the key strategy for reducing emissions to the target caps is expected to be the addition of emissions control equipment. The equipment includes scrubbers to reduce SO_2 and Hg emissions, SCR and SNCR equipment to reduce NO_x (SCRs with scrubbers also enhance Hg removal), and ACI equipment to reduce Hg. Switching to lower sulfur and lower Hg coal and reducing overall coal use is projected to play a fairly small role. The electricity price and cost impacts in these cases are not expected to be large, generally within a few percent of the prices seen in the reference case. The resource cost impacts are generally larger than the electricity price impacts in these cases, indicating that coal plant operators are projected to have to absorb some of the costs of compliance rather than pass them on to consumers.

In cases with a CO_2 emission cap, the key strategy for meeting the cap is a shift from coal to natural gas and renewables (particularly in cases with an RPS). The continued use of existing nuclear units and lower consumer electricity use in response to higher electricity prices also play a role. When an RPS is assumed with a CO_2 cap, the projected reduction in coal use is not quite as large as when an RPS is not included. In cases in which the CO_2 cap is set at 7 percent below the 1990 level, electricity generation from coal in 2020 is projected to be around 56 percent lower than in the reference case. When a 20-percent RPS is included, the reduction in coal-fired generation is not as large, at around 48 percent below the reference case level in 2020.

The electricity price and cost impacts in cases with a CO_2 emission cap are much larger than in those without a CO_2 emission cap. With caps on NO_x and SO_2 emissions set to 75 percent below their 1997 levels, an Hg cap set to 90 percent below 1997, and a CO_2 cap set to 7 percent below 1990, the price of electricity is projected to be 37 percent higher than the reference case level in 2010 and 38 percent higher in 2020. For the average household, annual electricity bills are expected to be $192 and $177 (20 and 18 percent) higher in 2010 and 2020, respectively. Total revenues for the power generation industry are projected to be $69 billion and $67 billion higher than the reference case projections in 2010 and 2020, respectively.

In contrast to the cases without a CO_2 emission cap, the resource cost impacts in the CO_2 cap cases are typically much smaller than the electricity price impacts. Because there are no economical CO_2 removal and storage technologies, the costs of CO_2 allowances fall on all fossil generators, and coal-fired plants, with their high allowance costs, often set the market-clearing price for electricity. Owners of plants that have relatively low CO_2 emissions—i.e., existing renewable, nuclear, and efficient natural gas units—could see large increases in profits in cases with CO_2 caps if they are allowed to sell power at market rates.

As with any 20-year projection there is considerable uncertainty about the results presented here. This is particularly true for the projections concerning Hg emissions control. As stated in Chapter 2, while a substantial amount of data about Hg emissions from coal plants has been collected in recent years, considerable uncertainty still remains about the measurement and control of Hg emissions. Numerous efforts are underway to test various removal technologies, but no full-scale tests have been carried out at this point. It is possible that new, innovative technologies will be developed that significantly lower the costs of Hg removal. The Hg technology sensitivity cases presented in this report are meant to illustrate the potential impact of successful technological breakthroughs. However, it is also possible that it may be very difficult to control all coal plant types to the required level—particularly in scenarios that call for a 5-ton cap or 90 percent removal at each plant.

In the cases with a CO_2 emission cap, uncertainty exists about the ability of the power sector to move rapidly from dependence mostly on coal to dependence on natural gas and renewables. Coal-fired power plants currently account for more than one-half of the electricity produced in the United States. Although the share produced by natural gas plants is projected to grow over the next 20 years as demand for electricity grows, it is unclear whether it could also take over a large part of the market now occupied by coal at the same time. The amount of power plant construction needed to replace retiring coal plants would present a serious challenge. In addition, recent history suggests that care would have to be taken to ensure that natural gas resources were developed rapidly to avoid price shocks. The integrated case with high natural gas prices illustrates the sensitivity of the projections to natural gas price assumptions.

In regard to nonhydroelectric renewables, the amount projected to be developed, particularly in those cases with an RPS, would multiply existing capacity by 16 times by 2020. Although total resource estimates suggest that there are considerable wind, biomass, and geothermal energy supplies in the United States, the technical and economic feasibility of developing the amount called for in these cases is not fully known. It is expected that the cost and performance of new renewable generating technologies stimulated by an RPS or the need to reduce CO_2 emissions would improve as they penetrated the market, but it is unclear that such technological improvement could offset the need to develop more expensive resources.

Careful planning would be needed in all cases to ensure the reliability of the electricity system during the transition period. In cases without a CO_2 cap, system reliability could be at risk during the period when a large amount of emissions control equipment is added. In many instances, plants must be taken out of service when final connections for emissions control equipment are made. If extended outages resulted or power suppliers did not coordinate their outages, the reliability of the system could fall, increasing the potential for price volatility.

In addition, in this analysis, new generating capacity is assumed to be built as needed to meet customer demand and maintain reliability in all years and regions. While this assumption is reasonable in the long run, it is not meant to capture the potential for market problems in the short run. For example, if the demand for electricity grew more rapidly than expected over the next few years or there were delays in the siting and permitting of needed new plants, the additional requirement to take a large amount of capacity out of service to add emissions control equipment could exacerbate a tight market situation, leading to larger near-term price impacts than are shown in this analysis.

Lastly, the electricity generation system in the United States is currently undergoing significant change—moving from a long period of average cost regulated prices to one in which power prices are expected to be set by market forces. It is unclear at this time how new competitive pricing practices—real-time rates, congestion charges, etc.—might influence consumer responses to the electricity price changes projected in this report. The exact form that each of the regional markets will take is not known at this time. Care will have to be taken to ensure that the policy instruments designed to reduce emissions will operate well within them. Each of the various policy instruments available—technology standards, emission taxes, cap and trade systems of various forms—would have different impacts on electricity prices and resource costs.