Executive Summary

Background

This analysis responds to a request from the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform[1] to examine the costs of power sector multi-emission reduction strategies (see Appendix A for the requesting letters). The Subcommittee asked the Energy Information Administration (EIA) to examine the impacts of imposing caps on power sector emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury (Hg), and carbon dioxide (CO_2), with and without a renewable portfolio standard (RPS).[2] Specifically, the Subcommittee requested "that EIA analyze the cost implications—the likely impacts on both consumers and energy markets" of various multi-pollutant strategies.

At the request of the Subcommittee, an initial analysis of emissions caps on NO_x, SO_2, and CO_2 was released in December 2000.[3] The current report extends the earlier analysis to add the impacts of reducing power sector Hg emissions and introducing RPS requirements. This report also incorporates the impacts of the higher natural gas prices seen in 2000 and early 2001. The emission caps on NO_x and SO_2 analyzed in this report are assumed to be phased in over the 2002 to 2008 time period. When the 1990-7% cap on CO_2 emissions is incorporated, it is assumed to be achieved over the 2008 to 2012 time period. The cap on Hg emissions is assumed to be fully effective in 2008.

Analysis Approach

The analysis in this report was prepared using the National Energy Modeling System (NEMS). NEMS simulates the energy investment and utilization decisions of the various sectors of the U.S. economy—i.e., households, commercial establishments, industrial facilities, and energy suppliers. When power sector emission caps are imposed, NEMS simulates the decision process in each economic sector to determine an appropriate compliance strategy. Unless otherwise specified, each of the emission caps imposed is assumed to be implemented under a "cap and trade" system patterned after the SO_2 allowance program created in the Clean Air Act Amendments of 1990 (CAAA90).[4] All electricity generators, excluding cogenerators, are assumed to be covered by the emissions caps. Electricity generators are assumed to behave competitively, incorporating the costs of emissions allowances in their electricity bid prices.[5] Because of the uncertainty inherent in any forecast, sensitivity cases are used to illustrate the importance of key assumptions in the analysis; however, numerous uncertainties remain, as discussed at the end of this Executive Summary.

Electricity Market Impacts

Reference Case

Over the next 20 years coal is expected to remain the most important fuel for electricity generation (Figure ES1). Its share of generation is expected to decline, however, because natural-gas-fired generating plants are expected to account for more than 90 percent of new power plant additions. The reference case for this analysis incorporates the CAAA90 NO_x and SO_2 regulations but does not include limitations on either Hg or CO_2 emissions.

After declining in 2000 and 2004 in response to current regulatory actions, NO_x emissions in the reference case are expected to rise slowly through 2020 (Figure ES2), but they are expected to remain below the 2000 level in 2020.

SO_2 emissions are also expected to decline as the second phase of the CAAA90 SO_2 allowance program takes

[1]In the 107th Congress this subcommittee has been renamed the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs.

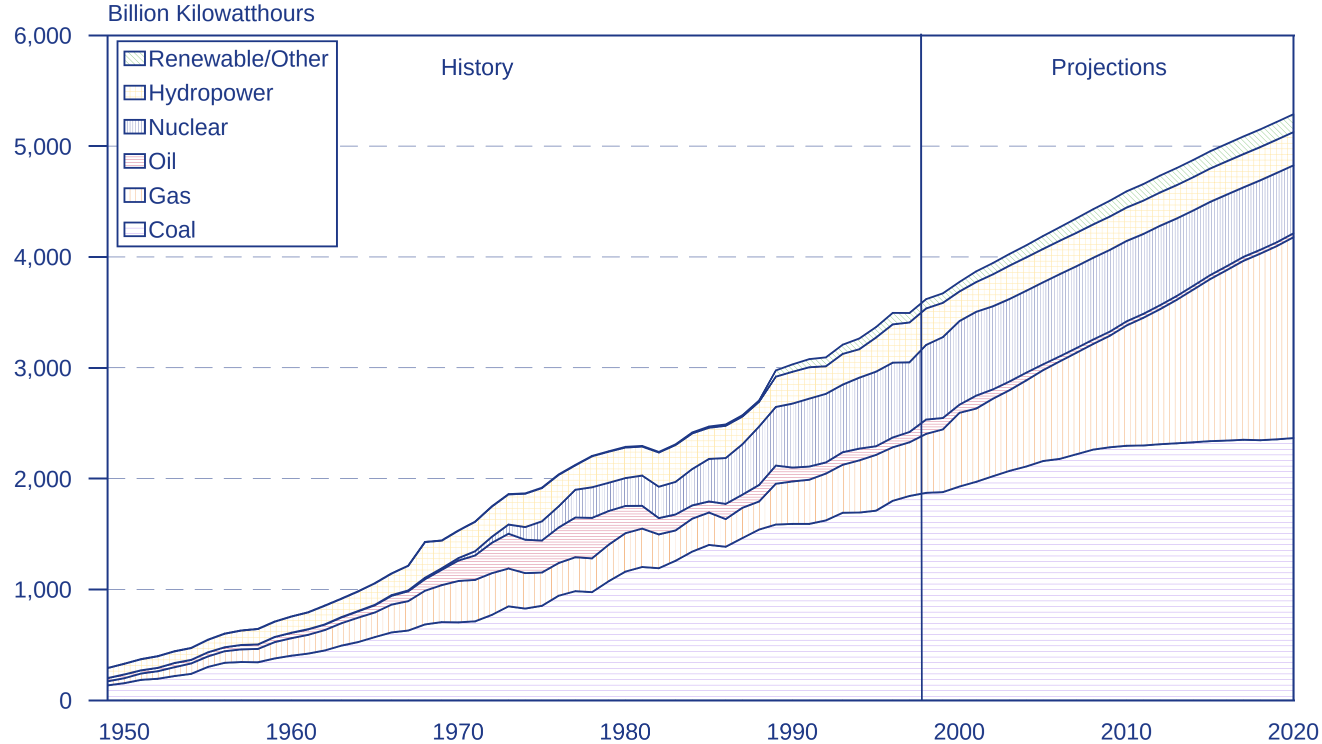
[2]A renewable portfolio standard (RPS) requires that qualifying renewable facilities generate a specified share of power sold. Qualifying renewable generators are issued credits for each kilowatthour they generate, which they can keep for their own use or sell to others who need them to meet the RPS requirement.

[3]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Nitrogen Oxides, Sulfur Dioxide, and Carbon Dioxide*, SR / OIAF / 2000-05 (Washington, DC, December 2000).

[4]The reader should be aware that numerous policy instruments—e.g., taxes, Maximum Achivable Control technology (MACT), no-cost allowance allocation with cap and trade, allowance auction with cap and trade, Generation Performance Standard (GPS) allowance allocation with cap and trade—are available. Each of the options would have different price and cost impacts.

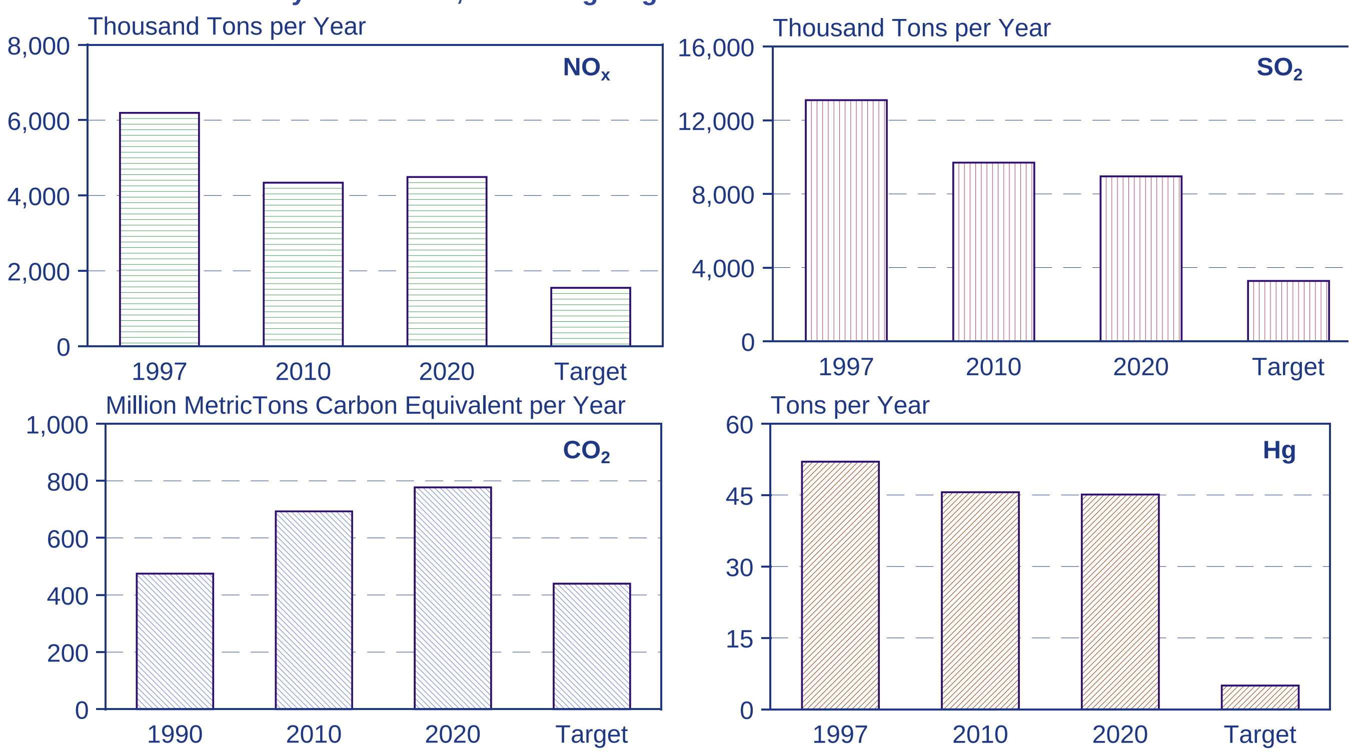
[5]One case prepared for this analysis assumed that emissions allowances would be treated as having zero value in regions where electricity prices continue to be based on cost of service rather than competitive pricing.

Figure ES1. 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.

Figure ES2. Historical Emissions, Reference Case Projections for 2010 and 2020, and Target Caps for Electricity Generators, Excluding Cogenerators



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run AEO2001.D101600A.

effect. Because power companies have accumulated (banked) allowances for later use, the 8.95 million ton SO_2 emission cap is not expected to be reached until well after the 2000 compliance date. Once the cap is reached, SO_2 emissions are expected to remain at that level through 2020.

Power sector Hg emissions are expected to remain fairly steady in the reference case over the next 20 years, at about 45 tons per year. Although coal use is expected to grow, the projected switch to lower sulfur—and lower Hg—coal and the addition of equipment to reduce SO_2 emissions reduces the increase in Hg emissions that might otherwise be expected.

Power sector CO_2 emissions are expected to increase steadily through 2020. The increased use of existing coal-fired power plants, the addition of a small number of new coal-fired plants, and growing dependence on natural gas to meet growth in the demand for electricity are the key factors in the increase.

Reducing NO_x and SO_2 Emissions

When it is assumed that NO_x and SO_2 emissions must be capped at 75 percent below their 1997 levels by 2008, power suppliers are projected to add emissions control equipment to meet the caps—scrubbers to reduce SO_2 emissions and selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) equipment to reduce NO_x emissions. They are also expected to shift toward lower sulfur coal to reduce SO_2. The mix of fuels used to generate electricity is expected to change very little from the reference case, with only a small shift from coal-fired to natural-gas-fired generation.

Although scrubbers, SNCRs, and SCRs can be expensive, they generally are not costly enough to make existing coal-fired plants uneconomical. Adding both NO_x and SO_2 control equipment would likely cost between $150 to $250 per kilowatt of generating capacity, as compared with the $500 to $1,000 per kilowatt that a new plant might cost. As a result, the average national price impacts of reducing NO_x and SO_2 are expected to be small, generally within 1 percent of the projections without the more stringent emission caps. The addition of SO_2 control equipment to meet the lower SO_2 cap also leads to a reduction in Hg emissions—lowering the annual total in 2020 by 13 tons (28 percent) from the level expected without the more stringent SO_2 cap.

Reducing Hg Emissions

As in the case of NO_x and SO_2 emissions, the key compliance strategy for reducing Hg emissions is projected to be the addition of emissions control equipment. The technology represented in this analysis is the use of activated carbon injection (ACI) with and without spray cooling and / or a supplemental fabric filter. This technology has been demonstrated in pilot-scale tests; however, there is substantial uncertainty about the ultimate cost and performance characteristics of ACI, because full-scale tests of the technology at high removal levels have not been completed. Other technologies, including advanced coal washing approaches, the use of alternative absorbents, systems to recycle activated carbon for repeated use, and systems to control NO_x, SO_2, and Hg emissions together, are in various stages of research and development. In addition, there is uncertainty about the role that SCRs may play in reducing Hg emissions. Although it is possible that some of these technologies will prove economical, it may be difficult or nearly impossible to remove 90 percent of the Hg from certain coal types in some power plant configurations.

When it is assumed that power suppliers must meet a 5-ton national cap (90 percent below the 1997 level) on annual Hg emissions by 2008, they are projected to switch to lower Hg coal, add scrubbers that reduce both SO_2 and Hg emissions, and add ACI equipment. In addition, electricity producers are expected to reduce their use of coal slightly and increase their use of natural gas. The average Hg content of coal used for electricity generation is projected to fall by 15 percent between 2000 and 2020 as generators reduce their emissions to meet the targets, assuming that a cap and trade program is implemented for controlling Hg emissions. They are also projected to add scrubbers to 52 gigawatts of capacity to reduce Hg and SO_2 emissions, as compared with about 15 gigawatts when the CAAA90 SO_2 cap (8.95 million tons per year) is assumed. The additional scrubbers are projected to reduce SO_2 emissions to 19 percent below the CAAA90 cap. Power suppliers are also projected to add ACI equipment to the vast majority of coal-fired plants and to reduce their overall coal-fired generation by 7 percent in 2010 and 2020 to meet the 5-ton Hg cap.

The actions needed to meet a 5-ton Hg emission cap are projected to have a larger price impact than those needed to meet the NO_x and SO_2 emission caps (Figure ES3). In this case, electricity prices are projected to be between 3 and 4 percent higher in 2010 and 2020. The price increases expected to result from the 5-ton Hg cap are projected to increase the Nation's total electricity bill by $8.4 billion in 2010 and $6.1 billion in 2020 relative to the reference case projections. When a less stringent 20-ton Hg cap is assumed, the electricity price impact is projected to be similar to that for controlling NO_x or SO_2 emissions, generally within 1 to 2 percent of the price expected without a cap. Similarly, if engineers are successful in developing more economical Hg control systems, such as ACI systems that allow large-scale recycling of activated carbon, the electricity price impact of meeting a 5-ton cap is also projected to be within 1 to 2 percent of the price expected without a cap.[6]

One important question with respect to reducing Hg emissions is whether they would be controlled with a cap and trade program, or whether maximum achievable control technology (MACT) standards would be set for each plant type. Because Hg is classified as a hazardous air pollutant (HAP), a MACT approach may be implemented. A cap and trade program would give power suppliers flexibility to reduce emissions at the lowest possible cost, but reductions under such an approach may not be uniform across the country.

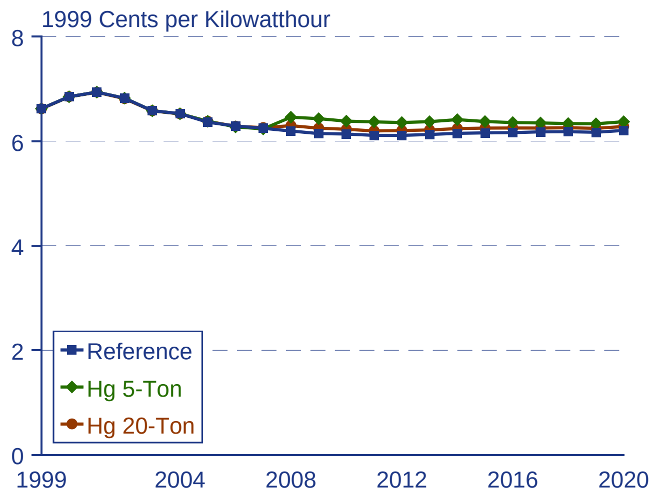
In an analysis assuming that all coal-fired power plants would be required to reduce the Hg in the coal they use by 90 percent, the results generally are similar to those of the 5-ton cap and trade case; however, there are several key differences. First, requiring all plants to reduce the amount of Hg in the coal they use by 90 percent would not achieve a 90-percent reduction in overall Hg emissions. Because the coal used annually in power plants is estimated to contain roughly 74 tons of Hg, a 5-ton cap actually represents a 93-percent reduction from the Hg content of the coal. Thus, a 90-percent MACT would force Hg emissions to 7.4 tons if there were no change in coal use. However, because coal use is expected to increase, Hg emissions in a 90-percent MACT case are expected to exceed this level. Projected power sector Hg emissions in 2020 when a 90-percent MACT standard is assumed are just over 8 tons—a reduction of approximately 84 percent from the 1997 level and more than 3 tons (60 percent) above the emission target assumed in the 5-ton cap and trade case.

The electricity price impacts under a MACT approach are projected to be lower than under a cap and trade system, because no Hg allowance prices would be reflected in power plant operating costs,[7] and the effective limit on Hg emissions would not be as stringent. The projections for regional Hg emissions in 2020 under the two regulatory approaches show only slight variations (Figure ES4). The results suggest that if large reductions—on the order of 90 percent—are required under either regulatory approach, there is likely to be little opportunity for overcompliance in some areas and undercompliance in others. In the Hg 20-ton case, however, the burden of reducing emissions is not projected to be spread as evenly, with the percentage reduction in most regions ranging from 47 to 75 percent in 2010.

Reducing CO_2 Emissions

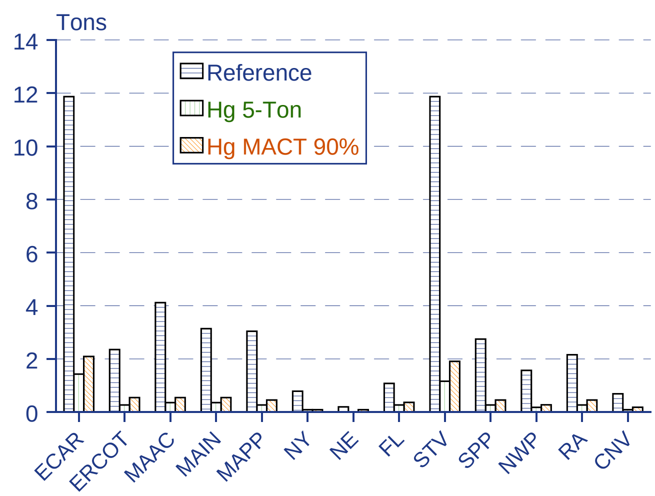
Unlike for NO_x, SO_2, and Hg, the primary compliance strategy for an assumed reduction in power sector CO_2 emissions to 7 percent below their 1990 level is projected to be a major shift in the fuels used to produce electricity (Figure ES5). To reduce CO_2 emissions, power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewable fuels. In addition, fewer nuclear plants are projected to be retired, consumers are expected to reduce their use of electricity in response to

Figure ES3. 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. See Chapter 2 of this report, pages 5-10, for case descriptions.

Figure ES4. Projected Regional Hg Emissions in the Reference, Hg 5-Ton, and Hg MACT 90% Cases, 2010

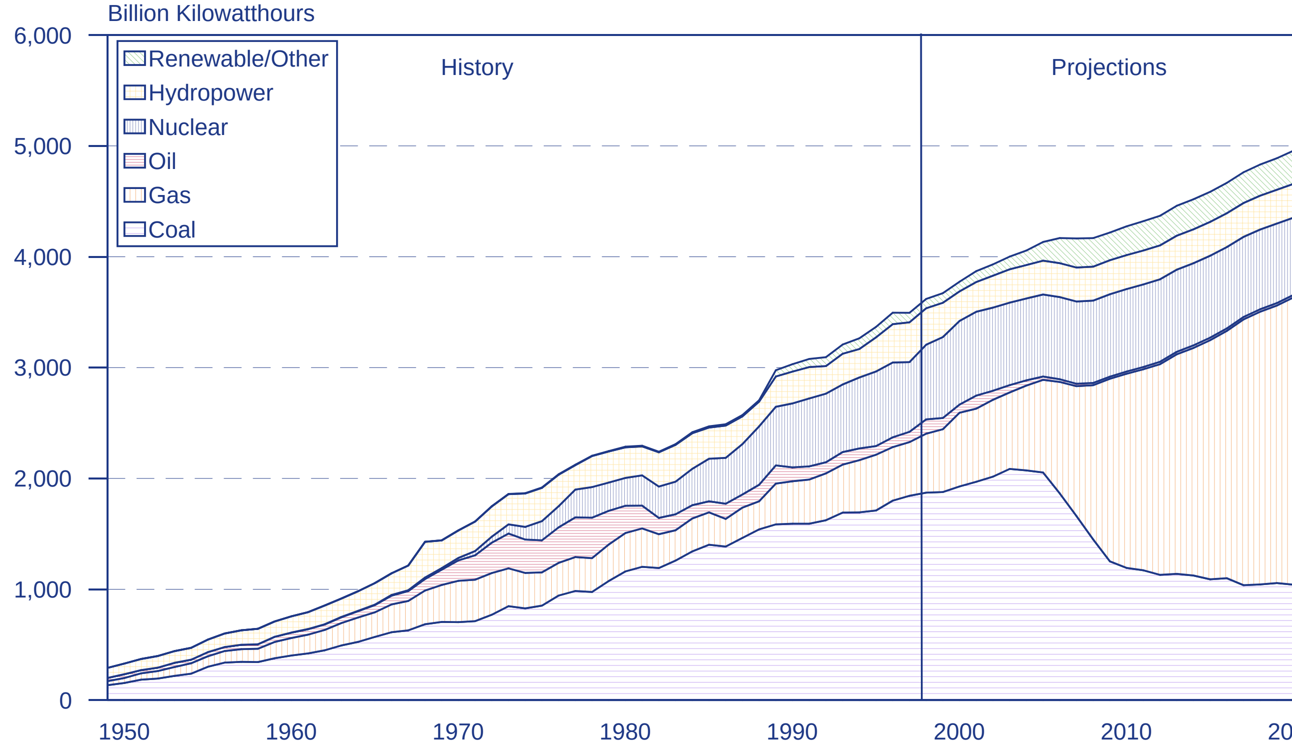


Source: National Energy Modeling System, runs M2BASE. D060801A, M2M9008.D060801A, and M2M9008M.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions. See Figure 26 in Chapter 4 for a map of electricity supply regions.

[6]The ACI recycling technology is meant to be representative of several Hg removal technologies that are now in various stages of development. It is impossible to predict at this time which technology might prove to be the most economical.

[7]Although coal-fired plants usually do not set market clearing prices, they do set them in some regions during periods of relatively low demand.

Figure ES5. Electricity Generation by Fuel, 1949-1999, and Projections for the CO_2 1990-7% 2008 Case, 2000-2020



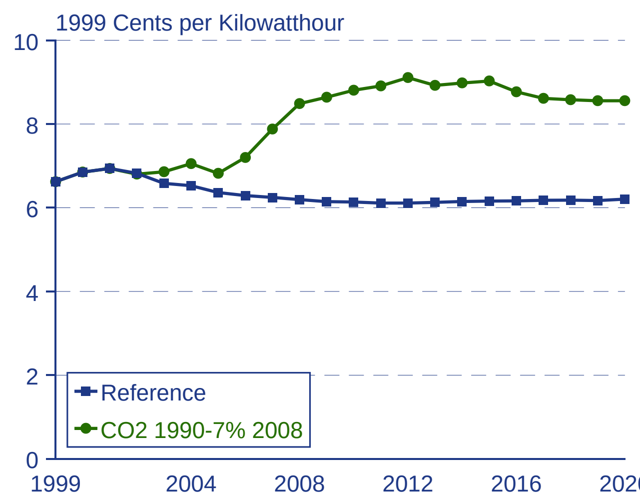
Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run M2C7B08.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions.

higher electricity prices, and cogeneration capacity is expected to grow to avoid higher grid-based electricity prices. In the later years of the projections, technologies for the capture and storage of carbon from fossil-fired power plants may emerge, but they are not expected to be economical in the time frame of this analysis.

Coal-fired electricity generation is projected to be 48 percent lower in 2010 and 56 percent lower than in the reference case in 2020 when a CO_2 cap at 7 percent below the 1990 level is assumed. Conversely, natural-gas-fired generation is projected to be 61 percent higher in 2010 and 43 percent higher in 2020. Similarly, renewable generation is expected to be 27 percent higher in 2010 and 32 percent higher in 2020. In addition, because nuclear capacity retirements are expected to be 14 gigawatts lower, electricity generation from nuclear power plants is expected to be 3 percent higher in 2010 and 14 percent higher in 2020 than projected in the reference case.

As a result of higher natural gas prices and the costs of CO_2 allowances purchased by power producers, electricity prices are projected to be much higher when CO_2 emissions are capped than when NO_x, SO_2, or Hg emissions are capped—43 percent higher in 2010 and 38 percent higher in 2020 than projected in the reference case (Figure ES6). Consumers are expected to reduce their electricity consumption by 8 percent in 2010 and 12 percent in 2020 when faced with higher electricity prices.

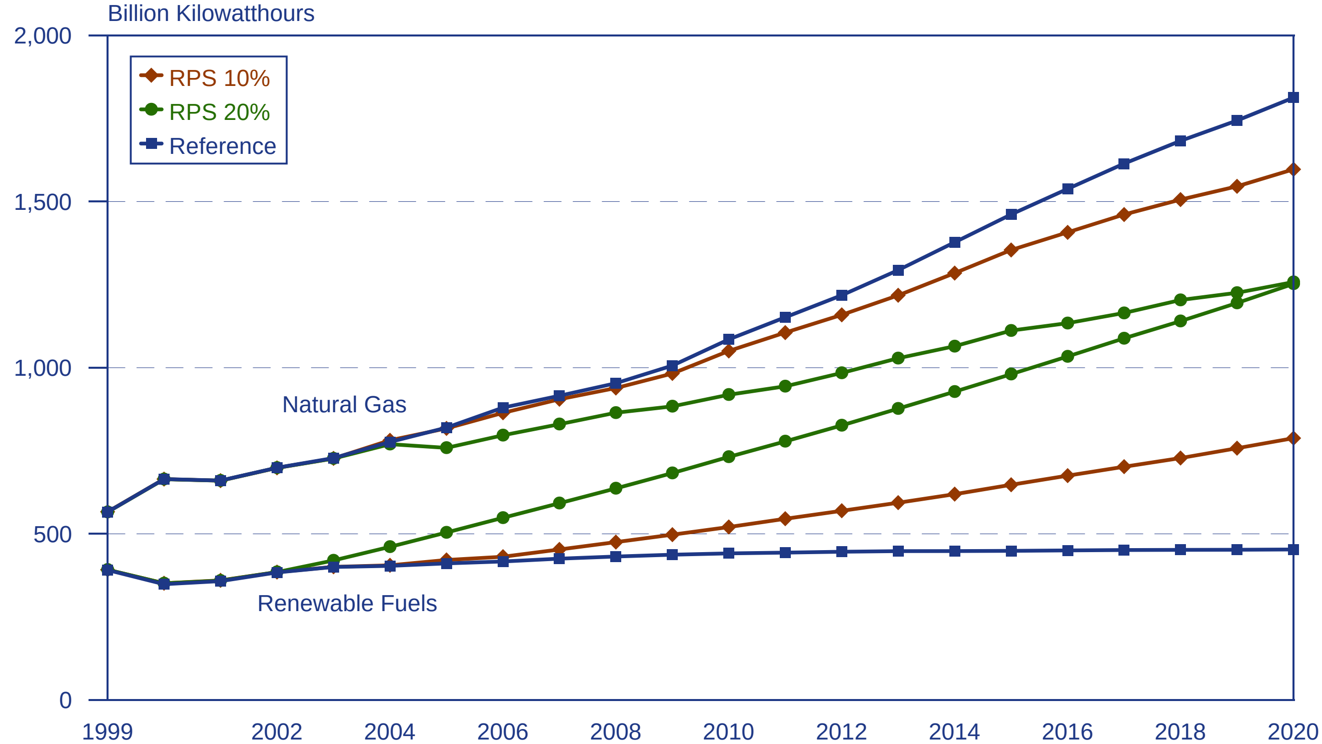
Figure ES6. Projected Electricity Prices in the Reference and CO_2 1990-7% 2008 Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A and M2C7B08.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions.

For the average household, annual electricity bills are projected to be $218 (23 percent) higher in 2010 and $173 (17 percent) higher in 2020 than in the reference case. Consequently, the Nation's total electricity bill is projected to be $80 billion higher in 2010 and $63 billion higher in 2020.

Figure ES7. Projected Electricity Generation from Natural Gas and Renewable Fuels in the Reference, RPS 20%, and RPS 10% Cases, 2000-2020



Note: Conventional hydroelectric generation, included in the projections shown in this figure, does not qualify under the RPS.

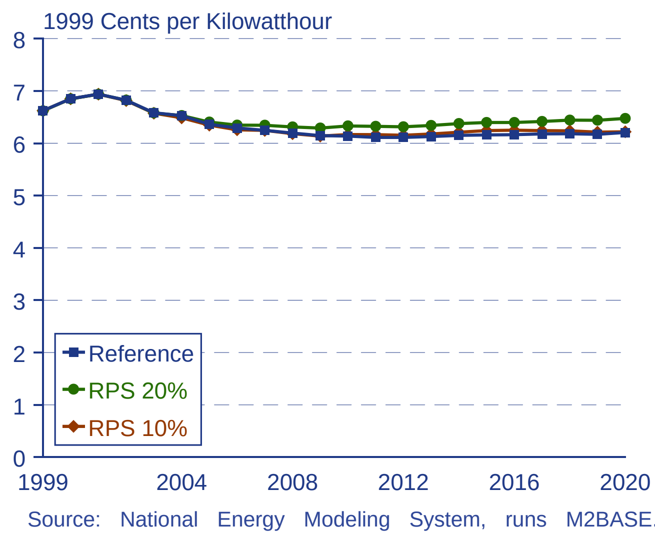
Source: National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_X.D070601A, and M2RPS20H_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

Implementing a Renewable Portfolio Standard

When it is assumed that 20 percent of electricity sales must be produced from nonhydroelectric renewable fuels over the next 20 years, electricity generation from renewable fuels is projected to increase at the expense of growth in natural gas and, to a lesser extent, coal use (Figure ES7). The key renewables expected to benefit from an RPS are biomass (co-fired in coal plants and dedicated plants) and wind. The development of the large amount of renewables needed to satisfy the RPS is projected to lead to higher electricity prices. To reach the assumed target of 20 percent of electricity sales generated from nonhydroelectric renewable sources by 2020, developers are expected to turn increasingly to more expensive renewable options. As a result, the renewable credit price—the subsidy needed to make the new nonhydroelectric renewable plants competitive with other generating options—is projected to be between 4 and 5 cents per kilowatthour between 2010 and 2020, in order to provide sufficient incentive for the electric power industry to build new renewable capacity rather than less expensive natural-gas-fired capacity.

The impact on electricity prices is much smaller than the renewable credit prices. Because each seller of electricity must hold renewable credits equal only to the required RPS share of renewables (i.e., 10 percent of sales in 2010 and 20 percent in 2020), the price of electricity when a 20-percent RPS is imposed is projected to be 3.3 percent higher in 2010 and 4.3 percent higher in 2020 than in the reference case (Figure ES8). However, the impact of the RPS on electricity prices is sensitive to the required RPS share. For example, when a 10-percent RPS by 2020 is

Figure ES8. 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. See Chapter 2 of this report, pages 5-10, for case descriptions.

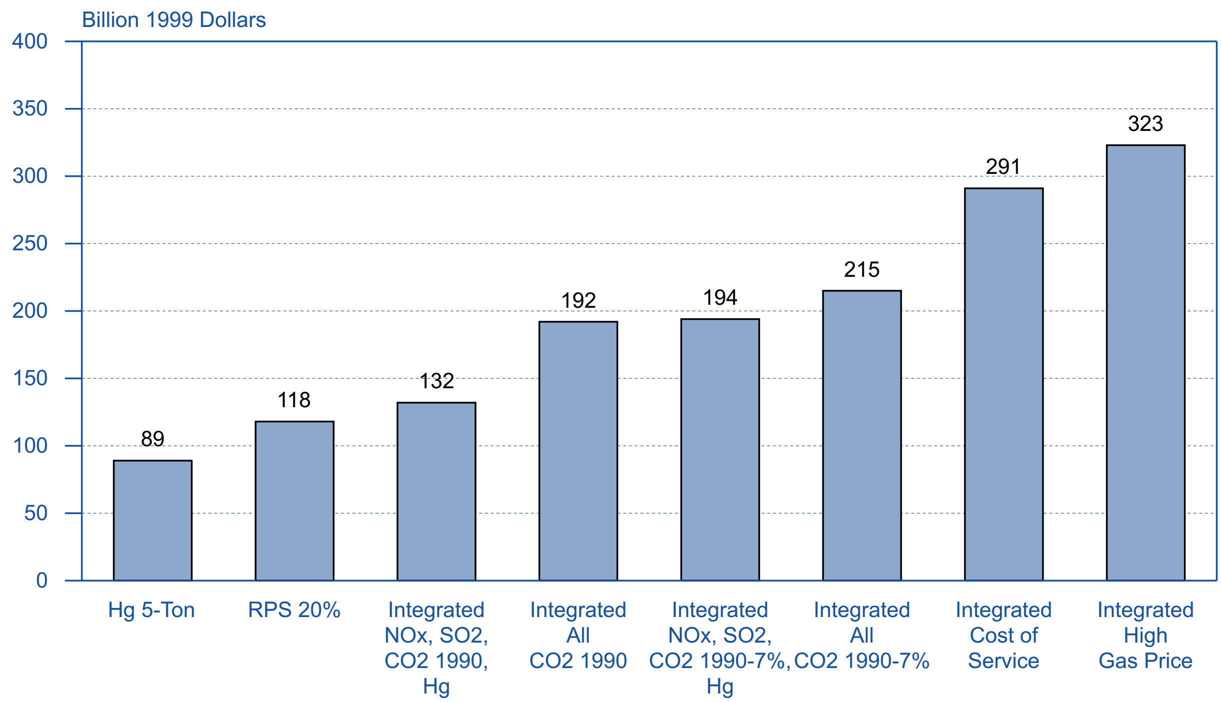
assumed, electricity prices are projected to be 0.5 percent higher in 2010 and 0.2 percent higher in 2020 than projected in the reference case—a much smaller increase than when a 20-percent RPS by 2020 is assumed.

Reducing Power Sector NO_x, SO_2, CO_2, and Hg Emissions Together, With and Without an RPS

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.

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 (Figure ES9). 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,[8] 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.[9] 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.

Figure ES9. 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.

[8]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.

[9]Retail electricity prices are assumed to be determined competitively in regions where most of the States have passed legislation or issued regulatory orders to deregulate their electricity sectors. In other regions, retail electricity prices are assumed to continue to be based on cost of service pricing.

When power sector CO_2 emissions caps are assumed—whether at the 1990 level or 7 percent lower—the effects of compliance efforts far outweigh the steps that would be taken to comply with the other emission caps. As in the case of a CO_2 cap alone, the primary compliance strategy is expected to be a major shift in the fuel mix used to produce electricity (Table ES1). Power suppliers are projected to shift away from coal to natural gas and, to a lesser extent, renewable fuels. In addition, fewer nuclear plants are projected to be retired, consumers are expected to reduce electricity use in response to higher electricity prices, and cogeneration capacity is expected to be expanded in response to higher grid-based electricity prices. The role of renewables is especially important when an RPS requirement is included (Figure ES10).

When CO_2 emissions are capped at the 1990 level, with or without other emission caps, coal-fired electricity generation in 2020 is projected to be approximately half the level projected in the reference case (Figure ES11), and the projected share of electricity generation from natural gas is much larger. When an RPS is included, the expected increase in renewable electricity generation dampens the increase in natural gas generation and slightly reduces the need to limit coal-fired generation. The addition of carbon-free renewables stimulated by the RPS lowers the need to reduce coal use to meet the CO_2 cap. In contrast, when the cap on CO_2 emissions is tightened to 7 percent below the 1990 level, the projected reduction in coal-fired generation is even larger.

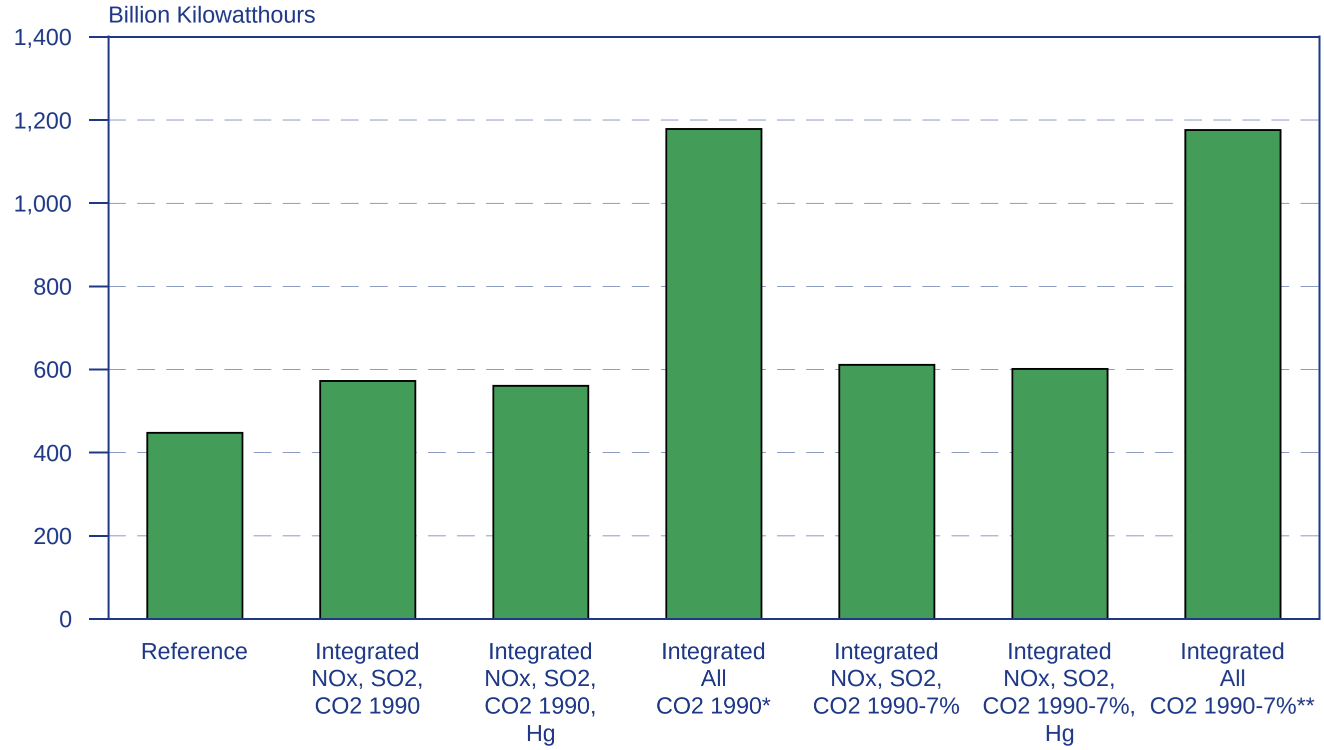
The combination of higher natural gas prices and CO_2 allowance prices is projected to lead to significant electricity price increases when a CO_2 cap is incorporated with other emission caps. As might be expected, when the CO_2 cap is set to 7 percent below the 1990 level, the

Table ES1. Key Results for the Electricity Generation Sector in Integrated Cases, 2010 and 2020

Analysis Case	Generation by Fuel (Billion Kilowatthours) Coal	Natural Gas	Renewable Fuels	Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	Electricity Price (1999 Cents per Kilowatthour)	Electricity Sales (Billion Kilowatthours)	Annual Household Electricity Bill (1999 Dollars)	Total Electricity Revenue (Billion 1999 Dollars)
2010								
Reference	2,297	1,085	436	2.87	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	8.13	3,873	1,108	315
Integrated NO_x, SO_2, $CO_2$1990, Hg	1,333	1,734	523	3.40	7.92	3,896	1,090	308
Integrated All CO_2 1990[a]	1,471	1,344	762	2.97	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	8.62	3,830	1,152	330
Integrated NO_x, SO_2, $CO_2$1990-7%, Hg	1,113	1,889	542	3.66	8.42	3,851	1,136	324
Integrated All CO_2 1990-7%[b]	1,268	1,512	745	3.13	8.59	3,830	1,147	329
Integrated Sensitivity Cases								
Integrated Moderate Targets	1,539	1,456	572	3.09	8.18	3,870	1,109	316
Integrated Cost of Service	1,046	2,025	554	3.96	7.68	3,956	1,069	304
Integrated High Gas Price	1,124	1,838	553	4.08	8.60	3,838	1,152	330
2020								
Reference	2,366	1,813	448	3.22	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	8.41	4,291	1,177	361
Integrated NO_x, SO_2, $CO_2$1990, Hg	1,124	2,584	561	3.72	8.36	4,309	1,172	360
Integrated All CO_2 1990[a]	1,390	1,784	1,178	3.09	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	8.63	4,218	1,185	364
Integrated NO_x, SO_2, $CO_2$1990-7%, Hg	1,032	2,608	602	3.74	8.55	4,257	1,182	364
Integrated All CO_2 1990-7%[b]	1,235	1,909	1,176	3.31	7.98	4,313	1,142	344
Integrated Sensitivity Cases								
Integrated Moderate Targets	1,413	2,138	755	3.74	8.19	4,318	1,158	354
Integrated Cost of Service	894	2,719	705	4.15	7.86	4,453	1,126	350
Integrated High Gas Price	1,082	2,098	735	5.05	9.27	4,188	1,237	388

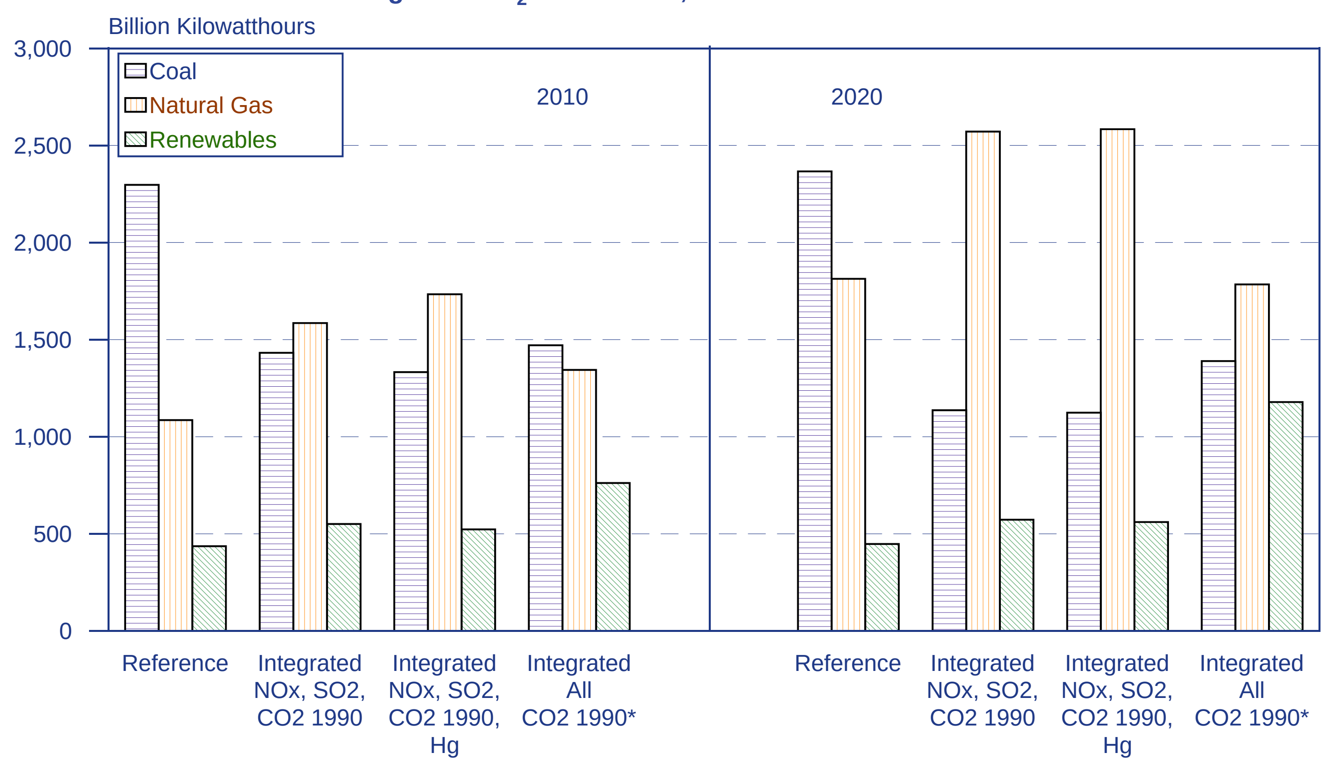
[a]Includes NO_x, SO_2, CO_2 1990, and Hg emissions caps and the 20-percent RPS by 2020.
[b]Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, M2P9008R_X.D070601A, M2NM7B08.D060901A, M2P7B08.D060801A, M2P7B08R_X.D070601A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A. See Chapter 2 of this report, pages 5-10, for case descriptions.

Figure ES10. Projected Electricity Generation from Renewable Fuels in the Reference Case and Integrated Cases with CO_2 Emission Caps, 2020



*Includes NO_x, SO_2, CO_2 1990, and Hg emissions caps and the 20-percent RPS by 2020.
**Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.

Figure ES11. Projected Electricity Generation from Coal, Natural Gas, and Renewable Fuels in the Reference and Integrated CO_2 1990 Cases, 2010 and 2020



*Includes NO_x, SO_2, CO_2 1990, and Hg emissions caps and the 20-percent RPS by 2020.
Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM9008.D060801A, M2P9008.D060801A, and M2P9008R_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

projected impact on electricity prices is larger than when the CO_2 cap is set to the 1990 level (Figure ES12). For example, the price of electricity in 2010 is projected to be 7.92 cents per kilowatthour when NO_x, SO_2, and Hg caps are combined with a CO_2 cap set to the 1990 level, but 8.42 cents per kilowatthour when they are combined with a CO_2 cap set to 7 percent below the 1990 level—29 percent and 37 percent higher, respectively, than in the reference case. The higher electricity prices are projected to lead to increases of $146 and $192, respectively, in annual household electricity bills and $53 billion and $69 billion, respectively, in the Nation's total electricity bill.

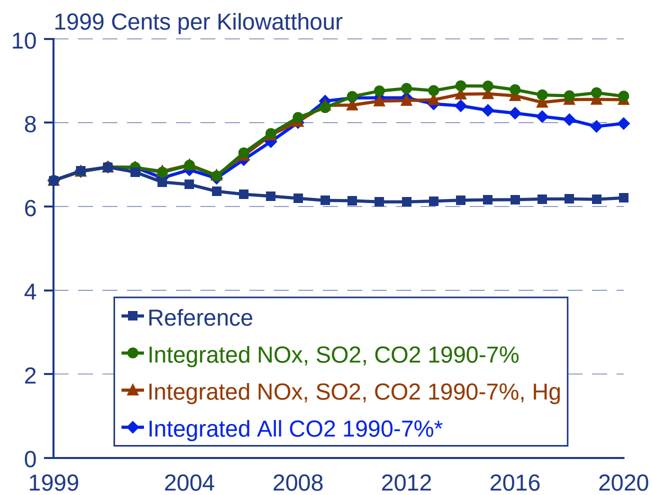
When an Hg emission cap is combined with caps on NO_x, SO_2, and CO_2 emissions, the impact on electricity prices is projected to be lower than when NO_x, SO_2, and CO_2 emissions caps are implemented without an Hg cap. As explained, the Hg reduction requirement increases the costs of continuing to operate coal-fired plants and reduces the CO_2 allowance price needed to stimulate power suppliers to turn from coal to natural gas and renewables. Because the CO_2 allowance price impacts all fossil fuel generators, when it is lower the costs of operating all fossil plants and the resulting electricity prices are also lower.

When an RPS is also included, the resource costs of compliance are projected to be $21 billion higher than they would be without he RPS. Electricity prices are projected to be higher in the early years of the forecast, when new renewable power plants are built rather than new natural-gas-fired plants. In the later years, however, the increased use of renewable fuels reduces natural gas consumption in the power sector, leading to a smaller projected increase in natural gas prices and lower CO_2 allowance prices and, in turn, a smaller increase in electricity prices.

Among the key assumptions that influence the projections when multiple emission caps are modeled are the levels of the emission caps, the approach used to price electricity, and the response of the natural gas market to increased demand from the electricity sector. For example, when less stringent caps on NO_x, SO_2, Hg, and CO_2 are assumed—requiring approximately half the reductions assumed in the more stringent scenarios—electricity prices in 2010 are projected to average 8.18 cents per kilowatthour, as compared with 8.59 cents per kilowatthour when the more stringent caps are assumed (Figure ES13).

Smaller increases in electricity prices are also projected when it is assumed that prices in many regions of the country will continue to be based on cost of service pricing. Regulators in those regions could treat any emissions allowances allocated to the companies they regulate as having zero cost, so that they would not be added to the operating costs of electric power plants. With this assumption, the price of electricity in 2010 is projected to be 9 percent less than when the wholesale power market is assumed to behave competitively—still 25 percent higher than without the stringent emission

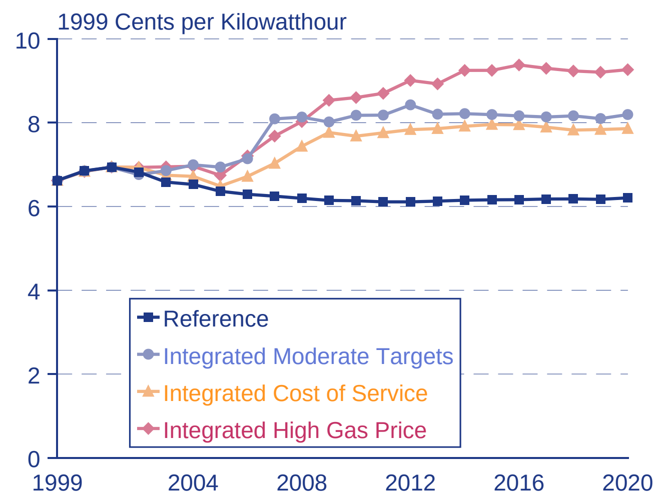
Figure ES12. Projected Electricity Prices in the Reference Case and Integrated Cases with 1990-7% CO_2 Emission Caps, 2000-2020



*Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.

Source: National Energy Modeling System, runs M2BASE.D060801A, M2NM7B08.D060901A, M2P7B08.D060801A, and M2P7B08R_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

Figure ES13. Projected Electricity Prices in the Reference Case and Integrated Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2PHF08R_X.D070901A, M2P7B08C.D060901A, and M2P7B08L.D060901A. See Chapter 2 of this report, pages 5-10, for case descriptions.

caps. However, power suppliers would have to take additional actions to reduce emissions, because consumers would not be expected to reduce their electricity usage as much as they would if electricity prices reflected the full opportunity costs of emissions allowances. As a result, supplier resource costs would be higher.

Electricity prices could be substantially higher if natural gas prices turn out to be higher than expected. When the reference case technology assumptions for natural gas discovery and production are replaced with assumptions of less robust technology development, the projected price of electricity in 2020 with combined NO_x, SO_2, Hg, and CO_2 emission caps is 9.3 cents per kilowatthour—49 percent above the reference case projection and 8.4 percent above the corresponding projection based on reference case natural gas technology assumptions. The higher natural gas prices would also lead to greater reliance on renewable fuels and more conservation by consumers. Of course, the same technology assumptions would lead to higher natural gas prices in the reference case, even without the imposition of new emissions caps.

Coal Market Impacts

Reducing NO_x, SO_2, and Hg Emissions

When stringent caps on power sector NO_x, SO_2, and Hg emissions are assumed to be imposed one at a time, coal consumption and production are expected to be reduced only slightly, because the primary response of power suppliers is projected to be the installation of pollution control equipment rather than a shift in fuel use. When a stringent SO_2 cap is assumed there is a projected shift away from lower sulfur coals, because adding scrubbers to reduce SO_2 would enable power producers to use less expensive higher sulfur coals. Similarly, when a 5-ton Hg cap is assumed, a shift to lower Hg coals is also expected, but adding activated carbon injection systems to capture Hg is expected to be the key compliance strategy.

Reducing CO_2 Emissions

Imposing a CO_2 emission cap, whether at the 1990 level or 7 percent below the 1990 level and with or without stringent NO_x, SO_2, and Hg emission caps, is expected to have a dramatic impact on coal use in the power sector. Because the carbon content of coal is the highest among the fossil fuels, power suppliers are expected to reduce their coal use to meet a CO_2 emission cap. For example, when a CO_2 cap set to 7 percent below the 1990 level is assumed, coal consumption for electricity generation in 2020 is expected to be 59 percent below the reference case level. The impacts are slightly less, with coal consumption in 2020 projected to be 54 percent lower than in the reference case forecast, when a CO_2 cap set to the 1990 level is assumed together with NO_x and SO_2 emission caps.

Natural Gas Market Impacts

Reducing NO_x, SO_2, and Hg Emissions

As with coal, reducing NO_x, SO_2, and Hg emissions is not projected to have large impacts on natural gas markets—generally increasing its use in the power sector by a small amount. More significant impacts are expected when Hg emissions are capped at 5 tons than when either an NO_x or SO_2 emission cap is assumed. For example, when Hg emissions are capped at 5 tons, electricity sector natural gas consumption is projected to be 0.8 trillion cubic feet (11 percent) higher in 2010 than in the reference case.

Reducing CO_2 Emissions

The impact on natural gas markets of capping power sector CO_2 emissions is projected to be much larger than the impacts of other emission caps. Power suppliers are expected to turn to natural gas if they are required to reduce CO_2 emissions. For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x, SO_2, and Hg, electricity sector natural gas consumption is projected to be 10.6 trillion cubic feet in 2010 and 13.4 trillion cubic feet in 2020, as compared with 6.8 trillion cubic feet and 11.2 trillion cubic feet projected for 2010 and 2020 in the reference case. The one exception is when a 20-percent RPS is included with the emission caps. In this case, the projected increased in generation from nonhydroelectric renewable fuels partially reduces the need to turn to natural gas.

To meet the increased demand for natural gas when CO_2 emission caps are assumed, both domestic production and imports of natural gas are expected to grow. Total U.S. gas supplies are projected to reach 38.5 trillion cubic feet in 2020 if stringent caps are placed on power sector NO_x, SO_2, Hg, and CO_2 emissions—approximately 3.2 trillion cubic feet above the reference case projection. Of the 3.2 trillion cubic feet projected to be added, 0.8 trillion cubic feet is expected to come from domestic resources and 2.3 trillion cubic feet from higher imports. The annual increases in production required between 2005 and 2010 would be near record levels, representing a serious challenge for the industry.

The projected increase in natural gas use for electricity generation when a cap on power sector CO_2 emissions is assumed is expected to lead to higher natural gas prices (Figure ES14). For example, when power sector CO_2 emissions are capped at 7 percent below their 1990 level in combination with stringent emission caps on NO_x,

SO_2, and Hg, the natural gas wellhead price is projected to be $3.66 per thousand cubic feet in 2010 and $3.74 per thousand cubic feet in 2020, as compared with $2.87 and $3.22 in the reference case.

Renewable Fuels Market Impacts

Reducing NO_x, SO_2, and Hg Emissions

When stringent caps on power sector NO_x, SO_2, and Hg emissions are assumed either one at a time or together, the projected impact on renewable fuel use for electricity generation is small. Because natural gas plants emit virtually no SO_2 or Hg emissions and very low NO_x emissions, they are expected to remain the most economical option when new electric power plants are needed. As a result, few new renewable power plants are projected to be built in response to stringent NO_x, SO_2, or Hg emissions caps.

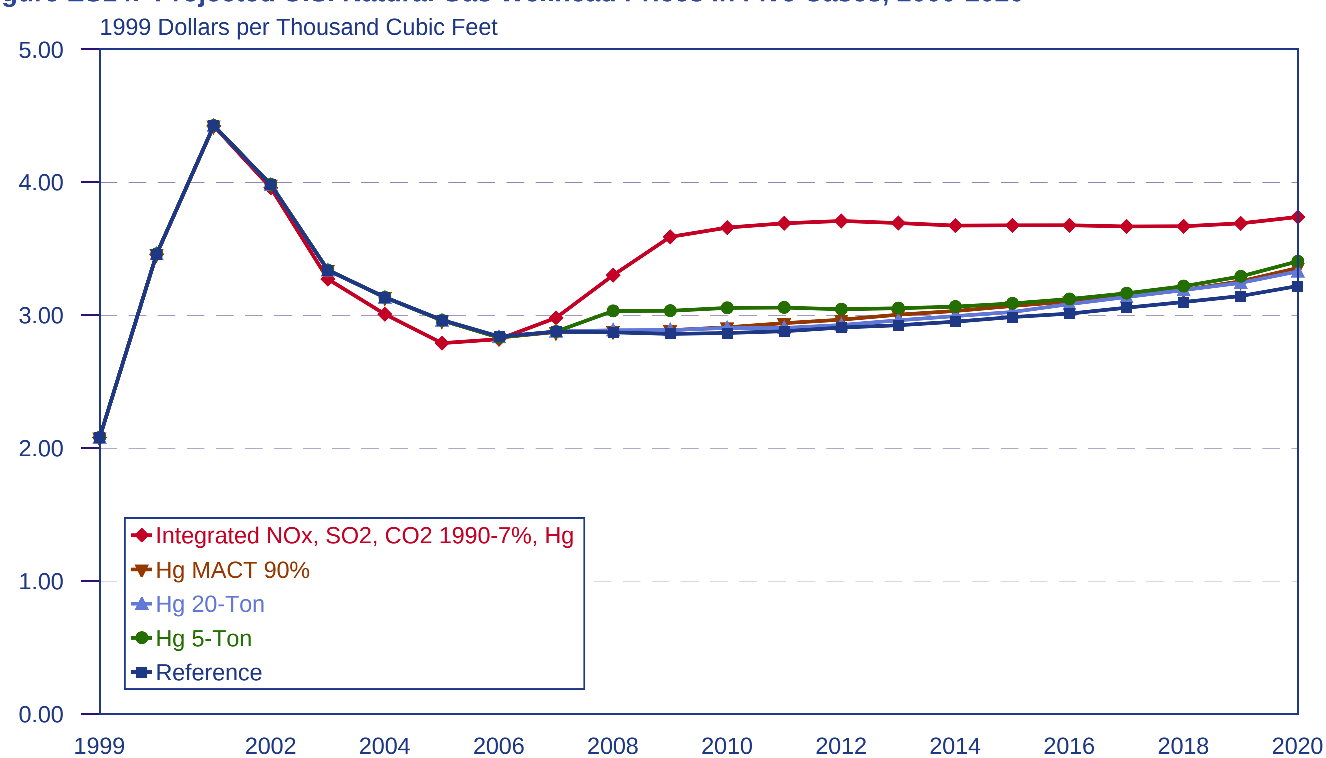
Reducing CO_2 Emissions

Imposing a CO_2 emission cap on the power sector—especially one set to 7 percent below the 1990 level—is projected to have a significant impact on the development of renewable generating facilities (Figure ES15). Although the primary compliance option for meeting a power sector CO_2 emission cap is expected to be increasing generation from natural-gas-fired power plants, the use of renewable fuels is also expected to grow, whether the CO_2 cap is assumed to be imposed alone or in concert with stringent caps on NO_x, SO_2 and Hg. The combination of higher natural gas prices as electricity suppliers consume more and the cost of CO_2 allowances begins to make new renewable plants economical. For example, when a CO_2 cap of 7 percent below the 1990 level is assumed, nonhydroelectric renewables are projected to provide 6.4 percent of U.S. electricity sales in 2020, up from 2.0 percent in 2000 and more than double the reference case projection of 2.8 percent in 2020. The key renewable energy technologies stimulated by a CO_2 cap are expected to be biomass (co-fired in coal plants and used in dedicated plants) and wind.

Implementing a Renewable Portfolio Standard

An RPS reaching 20 percent by 2020 is projected to have a larger impact on the use of renewable fuels for electricity generation than are power sector emission caps on NO_x, SO_2, Hg, and/or CO_2. In general, meeting emissions reduction requirements by adding emissions control equipment and/or changing the mix of fossil fuels used for power production is projected to remain less costly than switching to more expensive renewable alternatives in the absence of an RPS. The key renewables expected to be stimulated by a 20-percent RPS are biomass, wind, and geothermal technologies. By 2020 the generation from qualifying nonhydroelectric renewable technologies is projected to reach 932 billion

Figure ES14. Projected U.S. Natural Gas Wellhead Prices in Five Cases, 2000-2020



Source: National Energy Modeling System, runs M2BASE.D060801A, M2M9008.D060801A, M2M6008.D060801A, M2M9008M.D060801A, and M2P7B08.D060801A. See Chapter 2 of this report, pages 5-10, for case descriptions.

kilowatthours when a 20-percent RPS is assumed, as compared with 135 billion kilowatthours projected in 2020 in the reference case without an RPS.

Macroeconomic Impacts

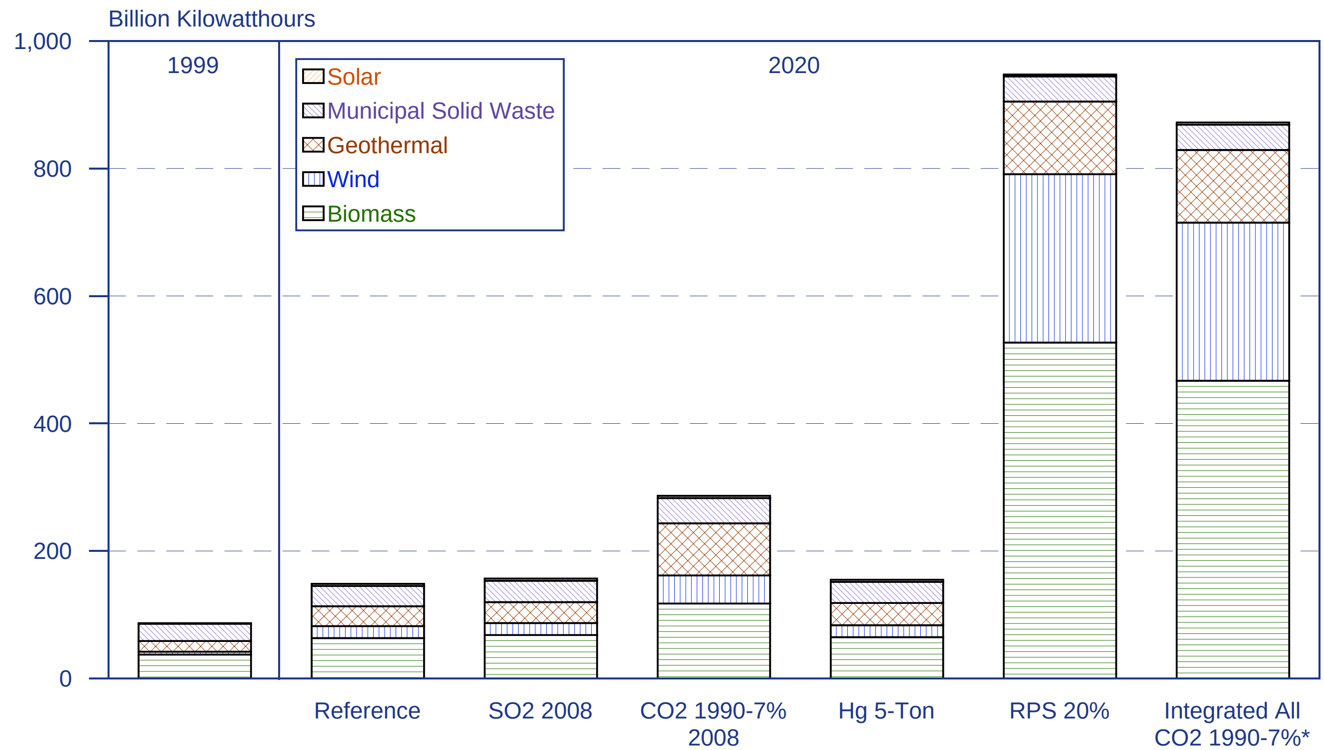
When stringent caps on power sector NO_x, SO_2, Hg, and CO_2 emissions are assumed, higher prices for electricity and natural gas are projected to have an impact on the U.S. economy. Higher energy prices would stimulate consumers to reduce their energy use and industries to shift to less energy-intensive production processes and products. The impact would be largest in the short term, when the economy first reacts to the higher prices. In the long run the economy is projected to recover and return to a more stable growth path. When the four emission caps are first phased in, the unemployment rate is projected to be as much as 0.4 percentage points higher and real gross domestic product as much as much as 0.9 percentage points lower in 2010 than projected in the reference case. By 2020, as the economy adjusts to the higher prices, real GDP is projected to be only 0.1 percent below the reference case level, and the unemployment rate is projected to be near the reference case level.

If, rather than a no-cost allocation of emission allowances, allowances were auctioned by the Federal Government, the economic impact could be different. The key question is what the Federal Government would do with the funds raised in the auction. If funds were returned to power suppliers, the effect would be the same as that of the no-cost allocation. If, on the other hand, they were given back to consumers in a lump-sum payment or through a cut in personal income taxes, the effect would be to help consumers maintain their level of overall consumption but reduce total investment. In the near term, this would be expected to reduce the impact on the economy, with GDP in 2010 projected to be 0.8 percent lower than in the reference case, as compared with 0.9 percent lower GDP with a no-cost allocation. In the longer term, the opposite would be the case: 0.4 percent lower GDP in 2020, as compared with 0.1 percent lower under the no-cost allocation scheme.

Uncertainties

As with any 20-year projections there is considerable uncertainty about the results of this analysis. The evolution of new technologies is unpredictable, and Hg emissions control technologies are relatively new and untested on a commercial scale. In addition, while a substantial amount of data about Hg emissions from coal-fired power plants has been collected in recent years, there still is considerable uncertainty in the measurement of Hg emissions. It is possible that new, innovative technologies could be developed that would lower the costs of Hg removal. In this analysis, an Hg technology sensitivity case is used to illustrate the potential impacts of

Figure ES15. Projected Electricity Generation from Nonhydroelectric Renewable Energy Sources, 2020



*Includes NO_x, SO_2, CO_2 1990-7%, and Hg emissions caps and the 20-percent RPS by 2020.
Source: National Energy Modeling System, runs M2BASE.D052301A, M2SO208P.D052401A, M2C7B08.D052301A, M2M9008.D052301A, M2RPS20_X.D070601A, and M2P7B08R_X.D070601A. See Chapter 2 of this report, pages 5-10, for case descriptions.

successful technological breakthroughs. It is also possible that for some coal-fired plants Hg emission reductions may be difficult to achieve, particularly to the levels that would be needed to meet a national 5-ton annual cap or a MACT standard of 90-percent removal. In addition, Hg control would be more expensive if power plant waste containing Hg were required to be treated as hazardous waste. Similar uncertainty exists for technologies designed to capture CO_2 emissions and sequester the carbon. Many technologies are being explored, but it is unclear whether they might be economical in the near term. If they do evolve quickly, the need to reduce coal use in the power sector dramatically to meet a CO_2 emission cap could be lessened.

In the case of CO_2 emissions, it is far from certain that the power sector would be able to move from dependence mostly on coal to dependence on natural gas and renewables in a relatively short time period without encountering supply problems. Coal-fired power plants currently account for more than one-half of the electricity produced in the United States, and although natural gas is projected to capture a larger share over the next 20 years in the absence of CO_2 caps as demand for electricity grows, it is not clear that it could at the same time also take over a large part of the market now occupied by coal. Undertaking the amount of power plant construction, natural gas drilling, and pipeline construction needed to replace retiring coal plants would be a serious challenge. In addition, recent history suggests that natural gas resources would need to be developed rapidly in order to avoid price shocks. In this analysis, an integrated case that includes higher natural gas prices illustrates the sensitivity of the projections to variations in future natural gas prices.

The changes required for electricity producers to comply with the power sector emission caps analyzed in this report, especially the caps on CO_2 emissions, are projected to cause significant shifts in the generating capacity and fuels used to produce electricity. There is substantial uncertainty about how the various fuel markets—for coal, natural gas, and renewables—might respond to the projected changes, as well as the degree to which consumers might respond to the projected increases in electricity prices. History does not offer clear guidance as to how the various markets might respond to changes as large as those required by the proposed emissions targets.

With respect to nonhydroelectric renewables, the amounts of new power generation capacity projected to be developed, particularly in cases with an RPS, would multiply existing renewable capacity by up to 16 times by 2020. While total resource estimates suggest that there are considerable wind, biomass, and geothermal resouces in the United States, the technical and economic feasibility of developing the amount called for in the RPS cases is not fully known. This analysis assumes that the development costs will increase as additional resources are used. If the cost increases are not as large as assumed here, the costs of an RPS could be lower than projected.

Careful planning would be needed in all cases to ensure that the reliability of the electricity system would not be compromised during the transition period. In cases without a CO_2 cap, system reliability could be of particular concern during the period when a large amount of emissions control equipment would have to be added. In many cases plants must be taken out of service when the final connections are made for new emissions control equipment. If extended outages resulted, or if power suppliers did not coordinate their outages to ensure that a large number of facilities would not be out of service at the same time, system interruptions could create the potential for price volatility in power markets.

Finally, wholesale electricity markets in the United States currently are undergoing significant change, moving from a long period of average cost regulated prices to a system in which power prices are set by market forces. The exact form that each of the regional markets will take is not known at this time. Changes in market structure as a result of the transition to competition could affect the choice of policy instruments needed to promote the efficient implementation of new emissions standards. Numerous policy instruments, including MACT standards, no-cost allowance allocation with cap and trade, allowance auction with cap and trade, and Generation Performance Standard (GPS) allowance allocation with cap and trade, are available. Each of the options would have different price and cost impacts.