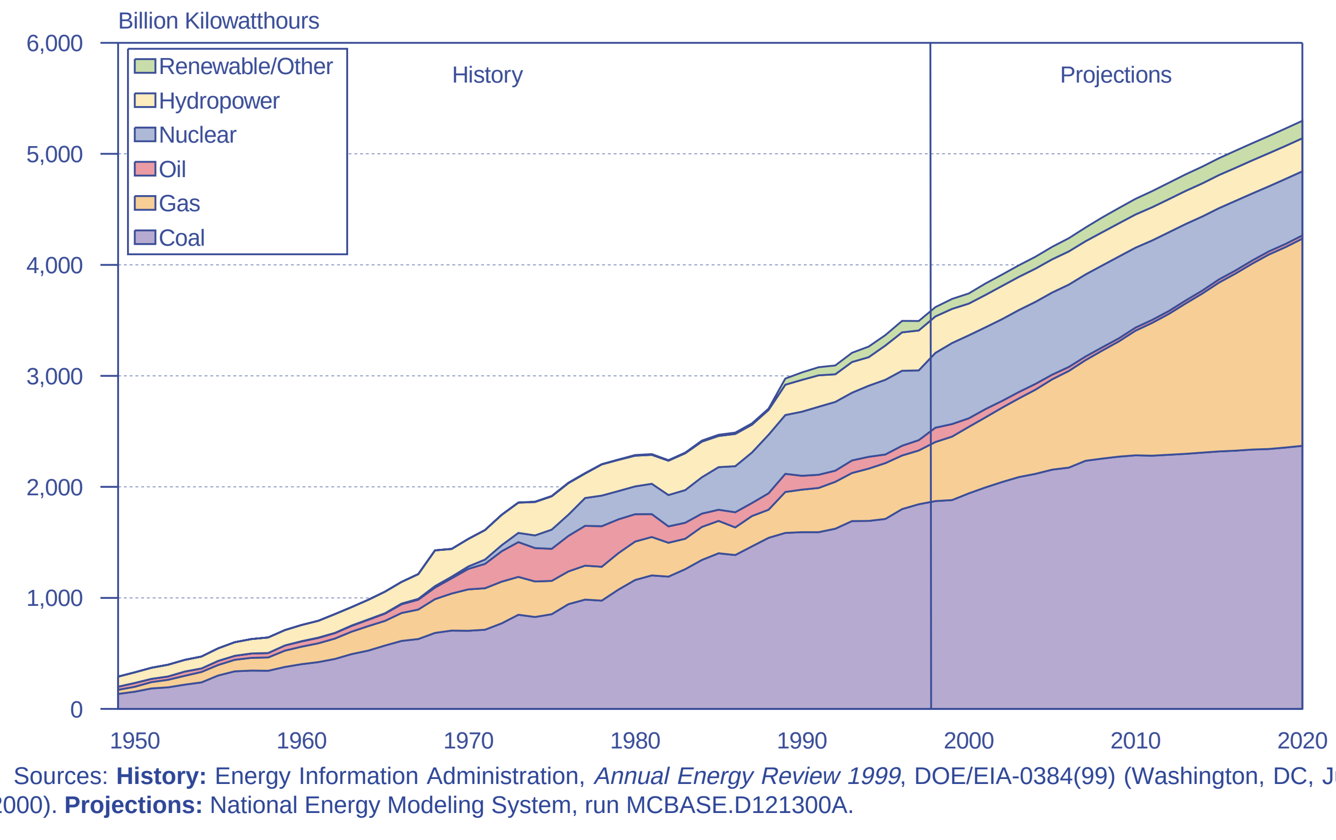
3. Electricity Market Impacts

Introduction

For the last 100 years, electricity production in the United States has been dominated by 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 2). 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 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 for a quarter century, and many previous orders have been canceled. 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. Although few new coal plants are expected to be added, existing coal plants are projected to be used more heavily as demand for electricity grows. Natural gas is expected to be the dominant fuel when new plants are needed. New natural-gas-fired combustion turbines and combined-cycle plants are the most economical options for most uses. New natural-gas-fired combined-cycle plants cost approximately half as much to build as new coal plants, are substantially more efficient, and have much lower emissions. These factors generally offset the higher fuel cost for natural gas. 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 forecast, and no new nuclear plants are forecast for the United States through 2020.

Figure 2. Electricity Generation by Fuel, 1949-1998, and Projections for the Reference Case, 1999-2020



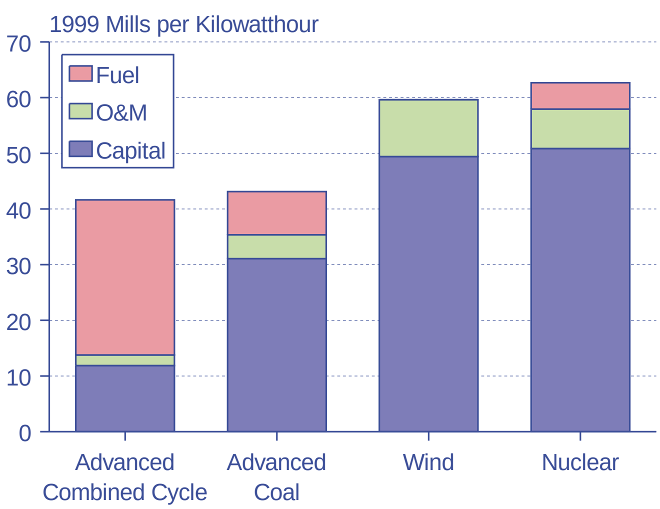
Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run MCBASE.D121300A.

In the NEMS projections, the imposition of the NO_x, SO_2, and, especially, the CO_2 emission caps analyzed in this report has impacts on all aspects of the electricity generation business. The emission caps affect capacity planning and plant retirement decisions, investments in emission control equipment, fuel choices for generation, electricity supply sector costs, and consumer prices. In turn, the change in electricity prices causes consumers to alter their electricity use by buying more efficient appliances, switching to other fuels, or generating their own electricity. This chapter discusses these issues together with the potential impact on total CO_2 emissions and key uncertainties in the projections.

Capacity Planning

In the reference case for the analysis, more than 410 gigawatts of new capacity (roughly 1,367 new 300-megawatt plants) is projected to be needed to meet the growing demand for electricity over the next 20 years and to replace 63 gigawatts of retiring power plants. The vast majority, approximately 92 percent, of the new capacity added is projected to be natural-gas-fired combustion turbines and combined-cycle facilities,[12] because their low construction costs and relatively high efficiencies make them economical for most uses. In terms of levelized costs—the costs of building and operating a new plant throughout its life—these plants are less expensive than other options for most uses (Figure 3). Other factors, such as their relatively small, modular size, low initial capital costs and low emission rates, also make them attractive.

Figure 3. Reference Case Projections of Levelized Costs for New Power Plants, 2005



Source: National Energy Modeling System, run MCBASE. D121300A.

New coal-fired plants can be economical when new plants are needed to serve continuous (baseload) needs, or when the difference between coal and natural gas prices delivered to power plants widens beyond $2.50 or so per million Btu. In the reference case this is projected to occur early in the forecast period, before gas prices begin declining from their current levels, and later in the projections, as increasing natural gas use leads to higher gas prices. For new renewable technologies, costs generally are projected to remain higher than those for coal and gas plants. Although costs have declined for wind, biomass, and solar generation technologies over the past 20 years, they still are not expected to be broadly competitive with new gas-fired plants for major capacity additions, absent subsidies or other support of some kind.

In the analysis cases, the dominant role of new gas-fired plants is projected to continue with the imposition of NO_x, SO_2, and CO_2 emission caps; however, the projections suggest that the caps would alter the economics of operating existing coal plants. Although coal plants are the major emitters of CO_2, SO_2, and NO_x in the power sector, they are very economical to operate. Producing some of the least expensive power available, the vast majority are projected to continue operating through 2020 in the reference case. When tighter emission regulations are assumed, however, operating and retirement decisions for the coal-fired plants now in operation are expected to change. Owners of the facilities will have to decide whether to pay the costs for emission allowances and fees, invest in new emission control equipment, or retire the facilities.

In the reference case, relatively few coal plants—10 gigawatts of capacity (just over 3 percent of total existing coal-fired capacity in 1999)—are projected to be retired (Table 6). In response to NO_x emission caps alone, whether imposed in 2005 or 2008, coal plant retirements are expected to be nearly the same as in the reference case. The primary compliance options to meet the NO_x emission caps are adding SNCR and SCR emission control equipment. In the reference case, SNCR and SCR controls are expected to be added to nearly 128 gigawatts of capacity to comply with the 19-State summer season NO_x cap beginning in 2004 (Table 7). In the 2005 and 2008 NO_x cap cases, however, more than twice that capacity—between 303 and 311 gigawatts—is projected to have one or the other post-combustion emission control technology added.

SNCR and SCR equipment can be expensive to add, especially to smaller plants that are used infrequently; but for many plants the projections indicate that it would be more economical to add the emission controls than to replace the plants. The EPA estimates used in

[12]See Appendixes A-I for detailed tables of the results for each of the cases.

Table 6. Projected Coal Plant Retirements, 2005-2020
(Cumulative Gigawatts of Capacity Retired After 1998)

Analysis Case	1999-2005	1999-2008	1999-2010	1999-2015	1999-2020
Reference	7	9	9	10	10
SO_2 Cap Cases					
SO_2 2005	9	10	10	11	11
SO_2 2008	8	9	9	10	11
SO_2 Sensitivity	9	10	10	11	11
CO_2 Cap Cases					
CO_2 1990-7% 2005	9	23	45	63	66
CO_2 1990-7% 2008	8	16	37	67	70
CO_2 Sensitivity	8	15	22	33	40
Integrated Cases					
Integrated 2005	7	20	41	58	66
Integrated 1990-7% 2005	8	22	47	73	79
Integrated 2008	7	16	35	62	68
Integrated 1990-7% 2008	7	17	42	85	90
Integrated Sensitivity	9	17	26	37	44

Source: National Energy Modeling System, runs MCBASE.D121300A (reference), MCNOX05.D121300A (NO_x 2005), MCNOX08.D121300A (NO_x 2008), MCSO205.D121300A (SO_2 2005), MCSO208.D121300A (SO_2 2008), MCSO205H.D121300A (SO_2 sensitivity), FDC7B05.D121300A (CO_2 1990-7% 2005), FDC7B08.D121300A (CO_2 1990-7% 2008), FDC7B05H.D121300A (CO_2 sensitivity), FDPOL05.D121300A (integrated 2005), FDP7B05. D121300B (integrated 1990-7% 2005), FDPOL08.D121500A (integrated 2008), FDP7B08.D121500A (integrated 1990-7% 2008), and FDP7B05H. D121300A (integrated sensitivity).

Table 7. Projected Additions of Power Plant Emission Controls, 1999-2020
(Gigawatts)

Analysis Case	Emission Control Technology		
	SNCR	SCR	FGD
Reference	39	90	15
NO_x Cap Cases			
NO_x 2005	59	252	14
NO_x 2008	60	243	15
SO_2 Cap Cases			
SO_2 2005	32	117	128
SO_2 2008	27	124	130
SO_2 Sensitivity	36	96	52
CO_2 Cap Cases			
CO_2 1990-7% 2005	16	42	0
CO_2 1990-7% 2008	22	54	0
CO_2 Sensitivity	26	54	0
Integrated Cases			
Integrated 2005	56	157	21
Integrated 1990-7% 2005	49	147	17
Integrated 2008	48	123	23
Integrated 1990-7% 2008	38	108	18
Integrated Sensitivity	26	60	8

SNCR = selective noncatalytic reduction. SCR = selective catalytic reduction. FGD = flue gas desulfurization (scrubbers).

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

this analysis show that adding SCR equipment to a 200-megawatt coal plant would cost approximately $72 per kilowatt and reduce NO_x emissions by between 70 and 80 percent.[13] Because only a few more coal plants are expected to be retired in these cases than in the reference case, there is little change in the projections for natural-gas-fired generation.

The primary options for reducing SO_2 emissions at coal plants are switching to lower sulfur coal, adding flue gas desulfurization (FGD) equipment (scrubbers), or retiring plants. In the reference case, to comply with the CAAA90 phase II emission cap, switching coal and adding scrubbers both play important roles. Scrubbers are expected to be added to approximately 15 gigawatts of

[13]U.S. Environmental Protection Agency, *Analyzing Electric Power Generators Under CAAA*, web site www.epa.gov.

capacity through 2020, while the share of coal consumption coming from lower sulfur western mines is projected to grow from 44 percent in 1999 to 58 percent in 2020. The price of SO_2 emission allowances is projected to be $170 per ton in 2010 and $246 per ton in 2020 in the reference case.

The requirements for tighter emission controls in the SO_2 cap cases are projected to lead to a slight increase in the number of coal plant retirements and an increase in scrubber additions among remaining coal plants. The 3,273,000-ton annual cap in the SO_2 cap cases would be difficult to meet primarily through switching to low-sulfur coal. Assuming that coal plants were to continue to operate as they do in the reference case, the 8,950,000-ton CAAA90 cap implies an average emission rate at coal plants of 0.8 pounds per million Btu—an average rate that can be achieved by scrubbing some plants and switching others to low-sulfur coal. Using the same assumptions, the 3,273,000-ton cap implies an average rate of approximately 0.3 pounds per million Btu—a rate that would be difficult to meet at most plants without adding scrubbers.

The 3,273,000-ton emission cap assumed in the SO_2 cap cases is not projected to be met until well after the effective dates of the caps, because it is assumed that power plant owners would be able to use any allowances they had accumulated through 1999. For this analysis it was assumed that the banked allowances would be used by 2015. As a result, the cap would not be fully binding until 2016 in the SO_2 cap cases. Because of the stringent cap in the SO_2 cases, between 128 and 130 gigawatts of capacity is projected to add scrubbers (Table 7). As in other cases, natural-gas-fired plants are expected to remain the most economical option when new plants are needed. As a result, projected additions of renewable plants are the same in the SO_2 cap cases and the reference case.

The expected SO_2 allowance prices in the SO_2 cap cases are much higher than those in the reference case (Figure 4). The initial response to the more stringent SO_2 cap is expected to include adding scrubbers to larger coal plants; retiring older, smaller coal plants; and adding new natural gas combined-cycle plants to replace them.

The projections for SO_2 allowance prices are sensitive to the variation in the assumed SO_2 emission target. The SO_2 allowance prices are projected to reach $735 per ton in 2010 in the SO_2 2005 case and $300 per ton in the SO_2 sensitivity case (Figure 5). Under the less stringent emission target assumed in the SO_2 sensitivity case, the expected need to add emission controls and switch to lower sulfur coals is significantly reduced.

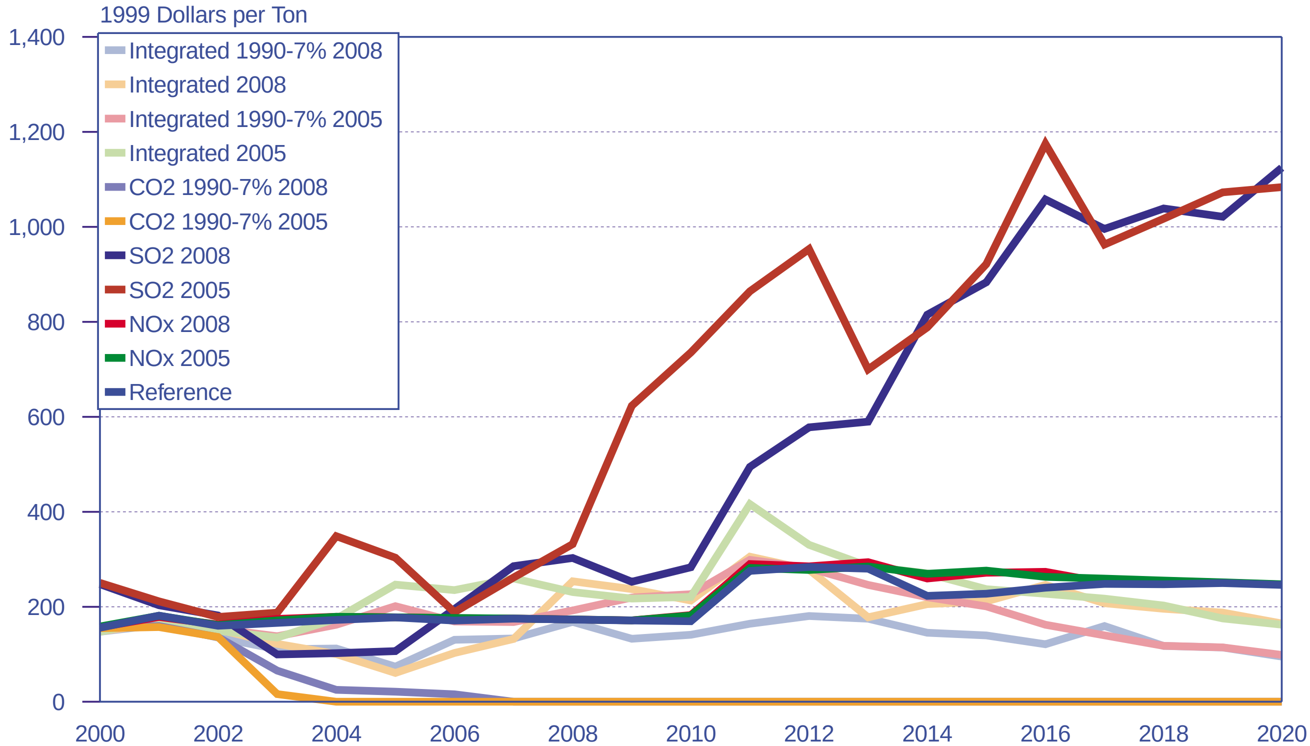
The amount of emission control equipment projected to be needed in the NO_x and SO_2 cap cases, particularly those with 2005 compliance dates, could cause system operational problems under some conditions. Typically, when new emissions controls are added, particularly SCRs, a plant must be off line for a time so that final connections can be made. Several recent studies have looked into whether the outage times (beyond normal maintenance outages) required to make final connections for equipment needed to meet the NO_x SIP call might lead to system operational and reliability problems. 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 work on their plants, and the interconnection time needed for each plant.

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 approach 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 grows more rapidly than expected over the next few years and/or delays occur in the siting and permitting of needed new plants, the additional requirement of adding a large amount of emission control equipment could exacerbate a tight market situation, leading to larger near-term price impacts than are shown in this analysis.

In the CO_2 cap cases, carbon allowance fees are expected to make it uneconomical to continue operating a large number of existing coal plants. In addition, no new coal plants are expected to be added. Unlike the NO_x and SO_2 cap cases, the CO_2 cap cases project that power plant operators would not be able to use emission control technologies to meet the assumed cap, at least not in the time horizon of this analysis. Instead they are expected to have to reduce their reliance on coal significantly and turn to lower carbon fuels, primarily natural gas. By 2020, between 66 and 70 gigawatts (22 to 23 percent) of existing coal plants are projected to be retired to comply with the CO_2 caps. The need for new NO_x and SO_2 emission control equipment is projected to be much lower in the integrated sensitivity case, because the CO_2 cap causes enough switching from coal to gas to allow the electricity generation sector to meet the assumed annual NO_x and SO_2 caps without adding much additional emission control equipment.

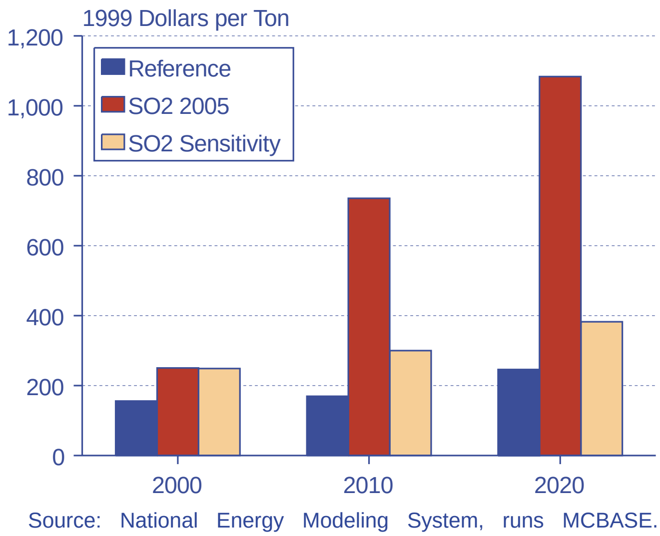
Carbon allowance fees in the CO_2 cap cases are projected to range from $139 and $143 per metric ton carbon equivalent in 2010 to $139 and $141 in 2020 (Figure 6). The integrated cases that set the carbon cap at 7 percent below the 1990 level produce the largest number of projected coal plant retirements and the largest projected increases in investments in new gas and renewable plants. The carbon allowance fee, which is assumed to be added to the electricity production price of all

Figure 4. Projected SO_2 Allowance Prices, 2000-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Figure 5. Projected SO_2 Allowance Prices, 2000, 2010, and 2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCSO205.D121300A, and MCSO205H.D121300A.

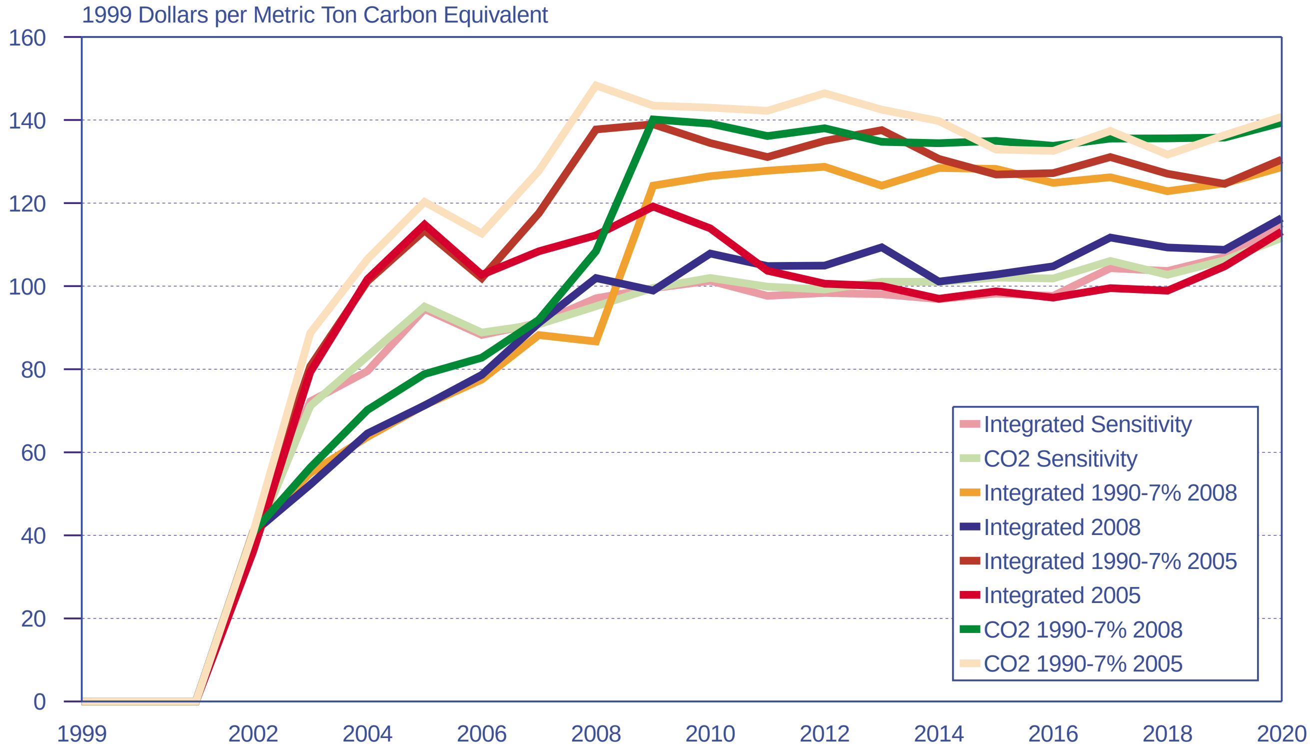
fossil-fired plants in proportion to the carbon content of their fuels, makes relatively low-carbon natural gas and carbon-free renewable and nuclear technologies more economically attractive than coal or oil facilities. It also makes maintaining existing nuclear plants more attractive than in the reference case. Relative to the reference case, between 49 and 66 gigawatts more gas-fired capacity and 34 to 38 gigawatts more renewable capacity are projected to be added,[14] and 12 to 17 gigawatts less nuclear capacity is projected to be retired.

In the CO_2 sensitivity and integrated sensitivity cases, the less stringent CO_2 cap is projected to lead to carbon allowance fees that are lower than those projected in the comparable CO_2 1990-7% 2005 and integrated 1990-7% 2005 cases. In 2010, the carbon allowance fees projected in the CO_2 sensitivity case are between \$37 and \$41 per metric ton carbon equivalent less than those projected in the comparable cases with the more stringent CO_2 caps. A large amount of new gas-fired capacity is still expected to be needed in these cases to meet the caps, but the amount of renewable capacity added—above the level projected in the reference case—is much less than projected in the cases with more stringent CO_2 caps. The relative economics of new renewable capacity are sensitive to the projected carbon allowance fees. In the CO_2 sensitivity and integrated sensitivity cases, between 16 and 18 gigawatts more new renewable capacity is projected to be built than in the reference case.

The results in the integrated cases essentially mirror those of the CO_2 cap cases; the magnitude of the projected changes in power plant operations to comply

[14]See Chapter 4 for a discussion of the specific renewables projected to be added.

Figure 6. Projected Carbon Fees, 1999-2020

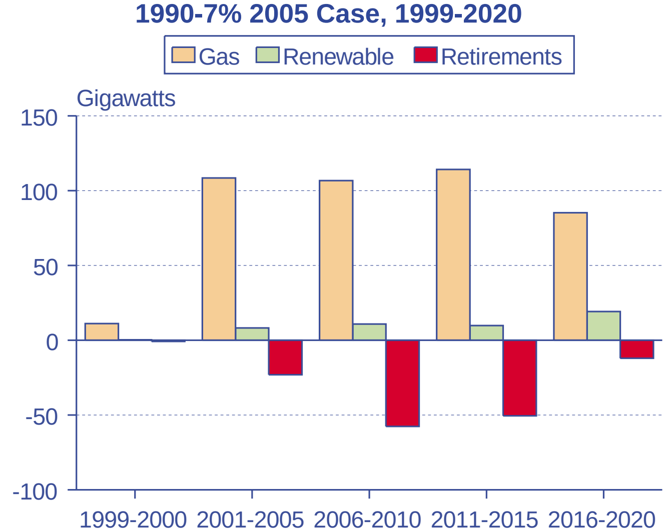


Source: National Energy Modeling System, runs FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

with the CO_2 cap generally overwhelms the projected impacts of the NO_x and SO_2 caps. New natural gas plants and, to a lesser extent, renewable plants are projected to be added to meet the growing demand for electricity and to replace retiring coal plants (Figure 7). The need for new capacity in the integrated cases, especially those with the 1990-7% CO_2 cap, is projected to require rapid construction of new plants. Almost 129 gigawatts of new capacity is projected to be needed in the integrated 1990-7% 2005 case by 2005. That rate of construction— averaging 21 gigawatts per year—would be more than double the rate of construction of new generating plants during the 1990s, which averaged only 7 gigawatts per year, and 26 percent above the level expected in the reference case.

Construction rates higher than 20 gigawatts per year were last seen in the 1980s, indicating that such construction levels are achievable. Figure 8 superimposes annual capacity additions for the period 1965 to 1985 on the projected additions from 2000 through 2020 in the integrated 1990-7% 2005 case, showing that the amount of new capacity projected to be needed in this case would be near the record levels seen in the past. This would be a difficult challenge to meet in a short time period. Combining the CO_2 cap with the NO_x and SO_2 caps is expected to reduce the need to add SNCR, SCR, and FGD equipment to reduce emissions from existing plants (Table 7), because so many coal plants are projected to be retired to meet the CO_2 cap.

Figure 7. Projected Capacity Additions by Fuel and Projected Retirements in the Integrated 1990-7% 2005 Case, 1999-2020



Source: National Energy Modeling System, run FDP7B05.D121300B.

The degree to which the CO_2 cap overwhelms the impacts of the other caps can be seen in the projections of NO_x and SO_2 emissions in the CO_2 cap cases (which assume no additional restrictions on NO_x and SO_2 emissions beyond those assumed in the reference case) (Table 8). In the CO_2 1990-7% 2005 case, power sector NO_x emissions in 2010 are projected to be 41 percent below their projected level in the reference case and within 0.9

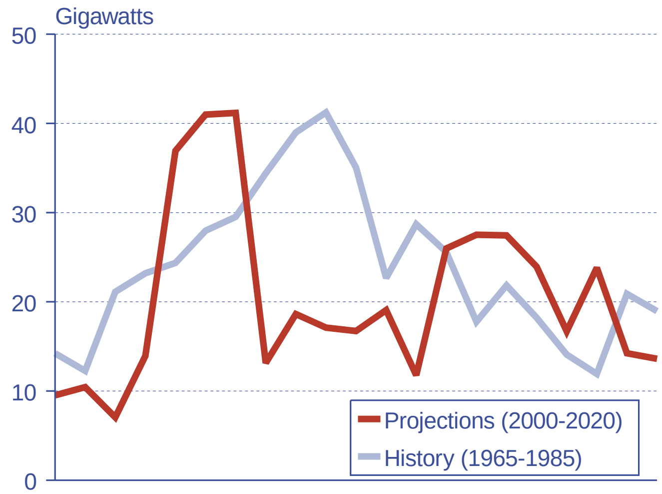
million tons of the more stringent NO_x cap. Similarly, SO_2 emissions in 2010 in the CO_2 1990-7% 2005 cap case are projected to be 17 percent below their projected level in the reference case.

As in the CO_2 cap cases, fewer nuclear power plants are projected to be retired in the integrated cases than in the reference case. Approximately 26 gigawatts (27 percent) of existing nuclear capacity is projected to be retired in the reference case, because it is expected that it will become less expensive to replace aging nuclear plants than to maintain them. In the CO_2 cap and integrated cases, however, the combination of carbon allowance fees and higher natural gas prices is projected to make replacing nuclear plants with coal or gas plants more expensive. As a result, fewer are expected to be retired. Total operating nuclear capacity in 2020 is projected to range between 84 and 89 gigawatts in the CO_2 cap and integrated cases, as compared with 72 gigawatts in the reference case and 97 gigawatts today.

In both the CO_2 cap and integrated cases, cogeneration and distributed generation capacity (in buildings) are projected to increase above the levels projected in the reference case. This analysis assumes that the proposed emission caps would not apply to cogeneration and distributed technologies located at customer sites. As a result, when the projected price of power from the grid increases, the economics of building on-site cogeneration or distributed generation facilities improve. In the reference case, cogeneration and distributed generation capacity additions are projected to total 19 gigawatts between 1999 and 2020. In the CO_2 cap cases the 2020 level is projected to be as much as 47 gigawatts higher. Similar changes from the reference case are projected in the integrated cases.

The vast majority of the cogeneration and distributed generation facilities projected to be built by 2020 in the CO_2 cap and integrated cases are expected to be fueled by natural gas, despite projections of higher gas prices in these cases than in the reference case as a result of projected increases in natural gas use for central station

Figure 8. Projected Annual Capacity Additions in the Integrated 1990-7% 2005 Case, 2000-2020, Compared with Historical Annual Capacity Additions, 1965-1985



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run FDP7B05. D121300B.

Table 8. Projected Emissions from Electric Power Plants, 2010 and 2020

Analysis Case	2010 NO_x (Million Tons)	2010 SO_2 (Million Tons)	2010 CO_2 (Million Metric Tons Carbon Equivalent)	2020 NO_x (Million Tons)	2020 SO_2 (Million Tons)	2020 CO_2 (Million Metric Tons Carbon Equivalent)
Reference	4.20	9.70	686	4.37	8.95	776
NO_x Cap Cases						
NO_x 2005	1.55	9.70	677	1.60	8.95	769
NO_x 2008	1.55	9.70	678	1.59	8.95	768
SO_2 Cap Cases						
SO_2 2005	4.04	3.67	676	4.25	3.27	776
SO_2 2008	4.16	4.12	688	4.28	3.27	781
CO_2 Cap Cases						
CO_2 1990-7% 2005	2.47	8.09	437	2.01	6.68	439
CO_2 1990-7% 2008	2.33	7.77	430	1.95	6.61	441
Integrated Cases						
Integrated 2005	1.37	4.22	474	1.18	3.27	477
Integrated 1990-7% 2005	1.30	3.92	443	1.12	3.27	440
Integrated 2008	1.42	4.52	476	1.22	3.27	477
Integrated 1990-7% 2008	1.32	4.02	430	1.16	3.27	440

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

electricity generation. For industrial cogeneration systems, combustion turbines burning natural gas are expected to be the preferred technology, although some systems currently being installed will use petroleum distillate fuels or byproduct gases from refining or chemical processes.

A number of factors make it unlikely that new coal-fired cogeneration systems will be built. For example, on a purely economic basis, the capital cost of new coal systems is significantly more than the cost of modern turbine-based natural gas systems—in many cases, more than twice as much. In addition, although fuel costs are higher, turbine-based systems cost less to operate and maintain than comparably sized coal plants. From a technical perspective, coal systems are appropriate only for a small portion of industrial facilities. Because coal systems use boilers and steam turbines, they generally have a power to heat ratio less than 0.5, which means that coal-fired generators can only be used at sites with high thermal loads. In addition, these boiler / steam turbine systems do not benefit from economies of scale at sizes below 40 megawatts, which restricts their market to larger industrial facilities. In contrast, combustion turbines can be cost-effective in systems as small as 1 megawatt, and they can be configured with power to heat ratios ranging from 0.5 to 4.0. Current environmental regulations also discourage the use of coal, with most new systems requiring significant secondary pollution abatement technologies to meet the emissions standards in their permits.

Generation by Fuel

The projected fuel mix for electricity generation in the NO_x and SO_2 cap cases (including the SO_2 sensitivity case) is not very different from that in the reference case. In the SO_2 cap cases slightly less coal-fired generation is expected (generally 1 to 2 percent less in 2020) and slightly more gas generation, because existing gas plants are projected to be used more intensively and new gas plants are projected to be added to replace the small number of coal plants that are expected to be retired.

In contrast, the projected shift from coal to natural gas and renewables is much larger in the CO_2 cap and integrated cases. Natural-gas-fired generation is projected to be much higher in the cases with CO_2 caps than in the reference case (Table 9). In the reference case, the share of generation coming from natural gas is projected to increase from 15 percent in 1999 to 20 percent in 2005, 24 percent in 2010, and 35 percent in 2020. In the integrated 1990-7% 2005 case, however, the projected natural gas shares are 34 percent in 2005, 43 percent in 2010, and 55 percent in 2020 (Figure 9). Because of the relatively high carbon content of coal—more than 70 percent higher per Btu than natural gas—the projected market-based carbon allowance fee would make it uneconomical to continue operating many coal plants. In addition, coal plants that are not retired are expected to be operated less intensively than in the reference case. The projected share of generation for coal-fired power plants in the integrated 1990-7% 2005 case is less than 17 percent in 2020, compared with 45 percent in the reference case.

Although the impact of power sector Hg emissions caps is not addressed in this report, the projected reduction in coal use in the CO_2 cap and integrated cases is expected to lead to lower mercury emissions. It is estimated that coal-fired power plants in the United States currently produce approximately 50 tons of Hg emissions per year, approximately one-third of total U.S. Hg emissions. Generation from other fuels produces much lower Hg emissions. With coal-fired generation projected to increase by 26 percent between 1999 and 2020 in the reference case, Hg emissions are projected to grow over time absent restrictions; however, the CO_2 cap and integrated cases are projected to lead to significant reductions in the use of coal and, hence, Hg emissions. In the most stringent case, the integrated 1990-7% 2005 case, coal-fired generation is projected to be 64 percent below the reference case level in 2020. Although the associated decline in Hg emissions would depend on the specific coal plants that continued generating, in percentage terms it could be similar to the change in coal-fired generation. As mentioned above, constraints on Hg emission will be examined in a later report.

Renewables are also projected to account for a much larger share of generation in the CO_2 cap and integrated cases than in the other cases (Table 10). Because renewable fuels produce virtually no NO_x, SO_2, or CO_2 emissions, their operating costs would not be affected by emission fees. As a result, they are expected to become more economical relative to fossil-based alternatives in the emission cap cases. In the reference case, because hydroelectric generation is expected to stay near today's level, the share of generation accounted for by renewable fuels is projected to change very little, falling slightly from 11 percent in 1999 to 8 percent in 2020. Generation from nonhydroelectric renewables is expected to grow, but not enough to increase the overall share from renewables.

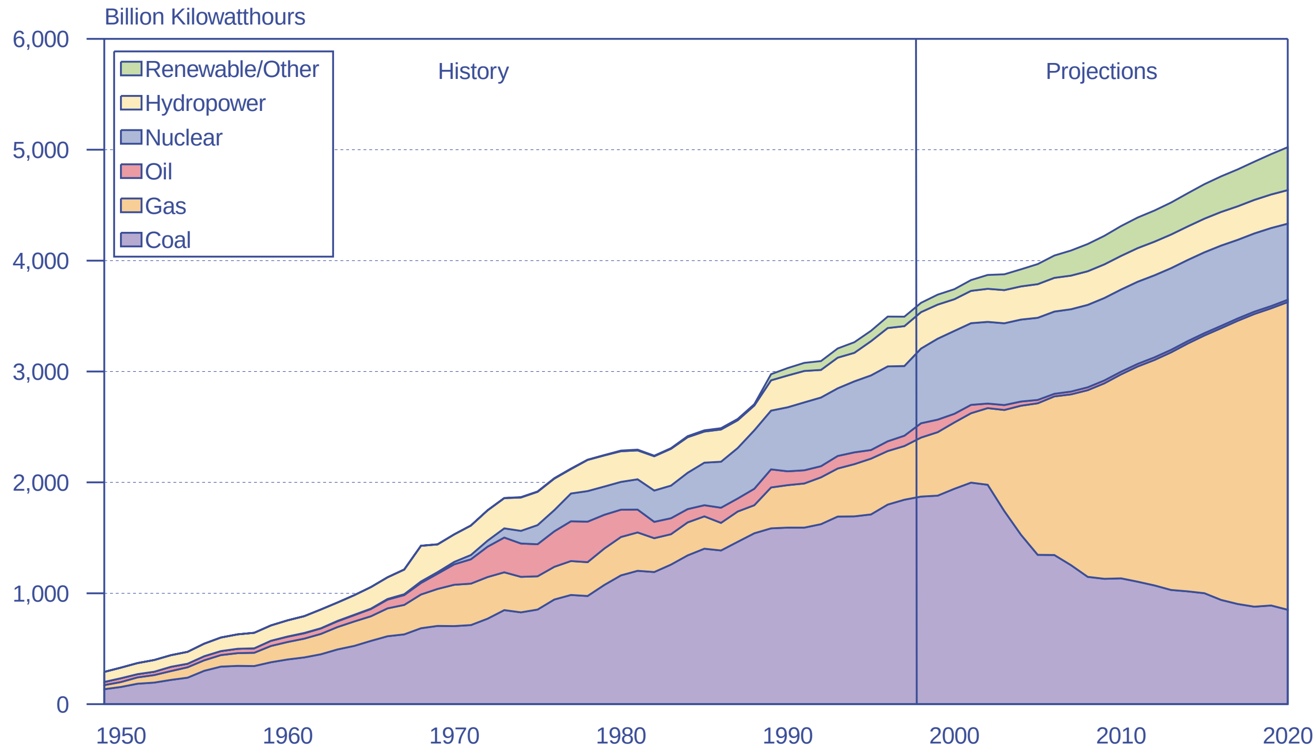
In the CO_2 cap and integrated cases, generation from renewables is expected to be much higher than projected in the reference case. The share of total generation coming from renewable facilities is projected to be as high as 14 percent in 2020 in the CO_2 1990-7% 2005 case. As discussed in Chapter 4, the projected level of renewable energy development, especially for nonhydroelectric renewables, in the CO_2 cap and integrated cases would be unprecedented in the United States and would require significant growth in the manufacturing and construction firms associated with renewable technologies.

Table 9. Projected Electricity Generation from Natural-Gas-Fired Power Plants, 2005-2020
(Billion Kilowatthours)

Analysis Case	2005	2008	2010	2015	2020
Reference	813	973	1,123	1,521	1,866
NO_x Cap Cases					
NO_x 2005	819	1,000	1,161	1,552	1,894
NO_x 2008	828	1,003	1,164	1,560	1,902
SO_2 Cap Cases					
SO_2 2005	816	1,015	1,195	1,574	1,911
SO_2 2008	801	1,003	1,146	1,570	1,901
CO_2 Cap Cases					
CO_2 1990-7% 2005	1,339	1,666	1,859	2,304	2,704
CO_2 1990-7% 2008	1,083	1,560	1,922	2,344	2,748
Integrated Cases					
Integrated 2005	1,369	1,525	1,746	2,301	2,752
Integrated 1990-7% 2005	1,367	1,683	1,839	2,324	2,774
Integrated 2008	1,060	1,615	1,789	2,309	2,746
Integrated 1990-7% 2008	1,098	1,590	1,935	2,365	2,816

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Figure 9. Electricity Generation by Fuel, 1949-1998, and Projections for the Integrated 1990-7% 2005 Case, 1999-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1999*, DOE/EIA-0384(99) (Washington, DC, July 2000). **Projections:** National Energy Modeling System, run FDP7B05.D121300B.

As with renewable capacity, the projections for renewable generation are sensitive to the assumed stringency of the CO_2 cap and the resulting carbon allowance fee. With the less stringent CO_2 cap assumed in the CO_2 sensitivity and integrated sensitivity cases, renewable generation is not projected to grow nearly as much from the reference case projections as it does in the comparable CO_2 cap and integrated cases. For example, in the CO_2 1990-7% 2005 case, generation from renewable facilities is projected to reach 712 billion kilowatthours in 2020—269 billion kilowatthours (61 percent) above the level expected in the reference case. In both the CO_2 sensitivity and integrated sensitivity cases, however, renewable generation is projected to reach between 586

Table 10. Projected Electricity Generation from Renewable Fuels, 2005-2020
(Billion Kilowatthours)

Analysis Case	2005	2008	2010	2015	2020
Reference	401	421	429	438	443
CO_2 Cap Cases					
CO_2 1990-7% 2005	477	542	574	620	712
CO_2 1990-7% 2008	483	551	581	610	679
CO_2 Sensitivity	481	539	559	563	595
Integrated Cases					
Integrated 2005	475	541	559	570	608
Integrated 1990-7% 2005	474	538	561	602	677
Integrated 2008	481	532	553	561	607
Integrated 1990-7% 2008	482	540	562	588	658
Integrated Sensitivity	479	532	553	558	586

Source: National Energy Modeling System, runs MCBASE.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

and 595 billion kilowatthours—143 to 152 billion kilowatthours (32 to 34 percent) above the reference case projection.

Electricity Costs and Consumer Prices

The addition of emission control equipment projected in the analysis cases, combined with the projected shift from coal to natural gas and renewables to comply with the emission caps, and the resultant emission allowance prices, has an impact on the costs faced by power suppliers and the electricity prices faced by consumers (Figure 10). In turn, the changes in prices lead consumers to alter their energy usage decisions, both for electricity and other fuels.

In the NO_x cap cases it is projected that $17 billion would be spent by power plant operators between 1999 and 2020 for new emission control equipment. These costs represent $7 billion above the projected expenditures in the reference case to comply with the NO_x SIP Call. Given that the 1998 net book value for plant investments for investor-owned utilities is over $363 billion, the projected costs are not large. Additional costs—in the form of lost revenue—would be faced by power plant operators who are projected to retire currently profitable plants rather than face the costs of upgrading them.

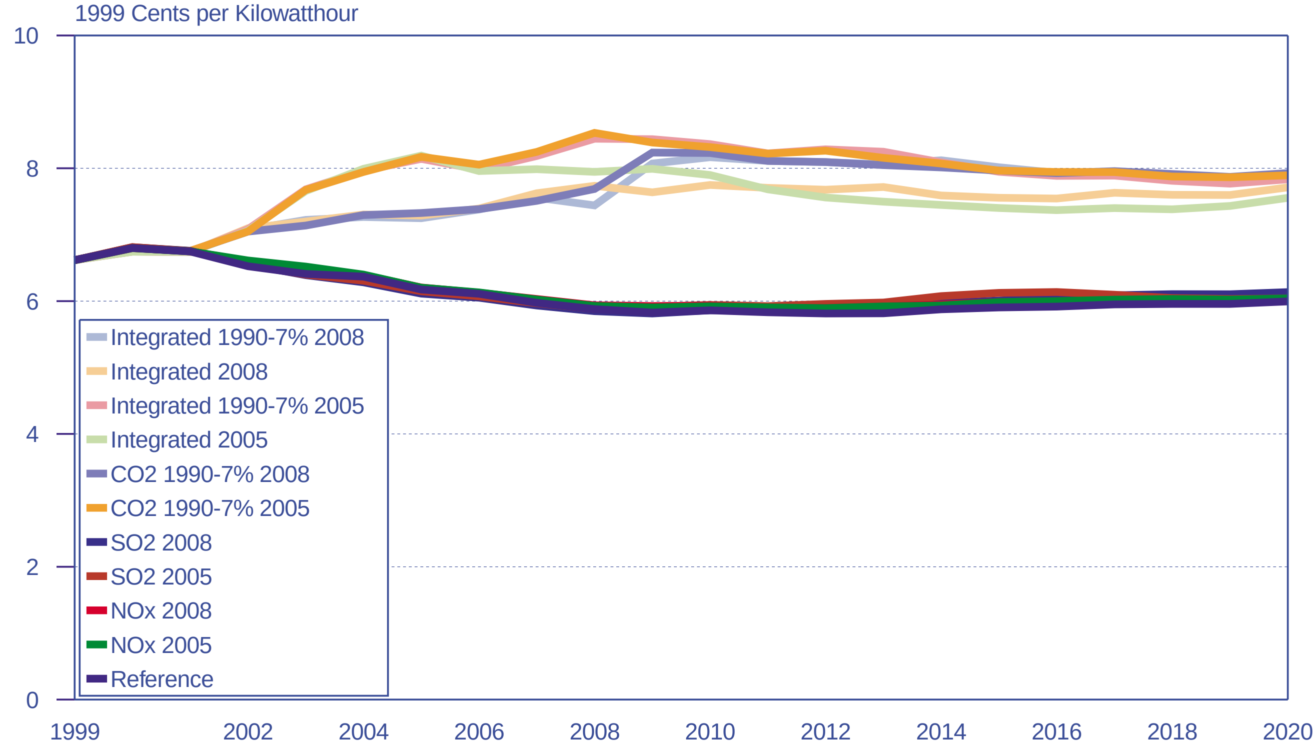
The increased costs for power plant operators, if incurred in generation markets with cost-of-service regulation, would be passed on directly to consumers in electricity prices. In competitively priced markets, however, the higher costs would be passed on to consumers only if they increased the operating costs of the generating plants that set the market price for power. For example, if SCR equipment were added to reduce NO_x emissions from a coal plant that did not set the market price for power, the costs of installing and operating the equipment would not be passed on to consumers as long as the plant's operating costs remained below the market price. In effect, the net profit from the plant would be reduced. Conversely, a plant with relatively low NO_x emissions that does not set the market price could see higher profits in these cases.

In the NO_x cap cases, a portion of the projected increase in electricity generation costs would fall on plants not setting the market price for power. In the NO_x 2005 case, the difference between the costs incurred and the increased revenue to power plant operators is projected to average $1.0 billion per year between 2005 and 2020 (Figure 11). The overall impact on electricity prices, however, is projected to be small. The price of electricity in 2010 is projected to be 1 percent higher than in the reference case.

In the SO_2 cap cases, as in the NO_x cap cases, the projected total investment in new emission control equipment would not be large relative to the $363 billion net plant investment for investor-owned utilities in 1998. Higher projected SO_2 allowance prices and greater dependence on natural gas would lead to higher generation costs and higher electricity prices. However, also as in the NO_x cap cases, a portion of the projected increase in generation costs would fall on plants not setting the market price for electricity (and a large part of the costs are fixed capital costs that do not affect operating costs), and therefore the full costs of investments in emission control equipment would not be passed on to consumers in electricity prices. The price of electricity in the SO_2 2005 case is projected to be roughly 1 percent above the reference case projection in 2010 and between 1 and 2 percent higher in 2020. Again, as in the NO_x cap cases, plants with low or no SO_2 emissions would see increased profits in these cases.

The impact on electricity prices is projected to be much larger in the CO_2 cap and integrated cases than in the NO_x and SO_2 cap cases, because there are currently no commercially available technologies for removing and storing (sequestering) CO_2. The only ways to make large

Figure 10. Projected Electricity Prices, 1999-2020

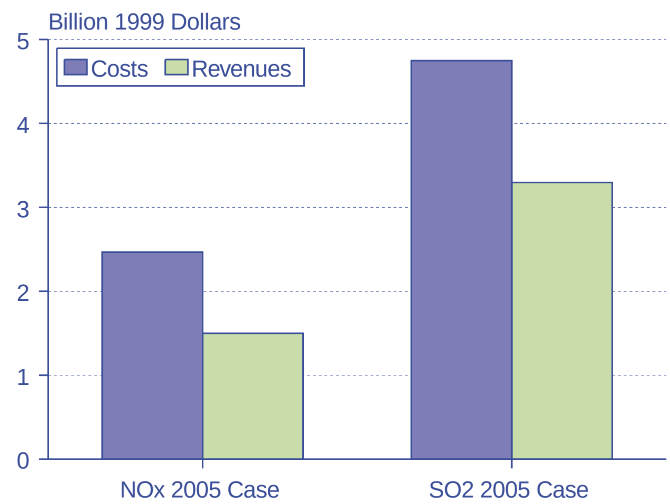


Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

reductions in CO_2 emissions are to reduce the consumption of fuels with relatively high carbon content or to increase the efficiency of electricity production and consumption. In addition, the CO_2 allowance price (throughout this report given in dollars per metric ton carbon equivalent) falls on all fossil fuel generators, those using coal, oil, and natural gas. Unlike in the NO_x and SO_2 cases, because all fossil plants are affected, the operating costs for plants setting the electricity market price are expected to increase, and consumer electricity prices are expected to increase with them. In these cases, owners of existing non-fossil-fuel plants—nuclear, hydroelectric, and other renewables—would see higher profits as market prices increased because of the CO_2 allowance price. The owners of relatively low carbon fossil plants, such as very efficient natural gas plants, could also benefit to a lesser degree.

Across the CO_2 cap and integrated cases, the price of electricity is projected to range from 17 percent to 33 percent higher than the reference case projection in 2005. Because the assumed compliance dates are less than 10 years away, markets would not have much time to adjust and take advantage of normal capital turnover. As a result, the largest differences in projected electricity prices relative to the reference case generally are seen from 2005 to 2009. In the later years of the projections, when new gas-fired and renewable generation facilities are expected to be in operation, the projected differences from the reference case are smaller. By 2020, prices in the

Figure 11. Projected Average Annual Changes from Reference Case Power Plant Costs and Revenues in the SO_2 and NO_x 2005 Cap Cases, 2005-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, and MCSO205.D121300A.

CO_2 cap and integrated cases are projected to be between 26 and 32 percent higher than projected in the reference case. Because of the higher prices expected in the CO_2 cap cases and integrated cases, electricity consumers are projected to reduce their consumption of electricity by 5.5 to 7.5 percent on average relative to the reference case over the 2005 to 2020 time period.

In each of the analysis cases, particularly the cases with CO_2 emission caps, the total impacts on electricity prices reflect both the change in resource costs (higher fuel and operating and maintenance costs) and the allowance costs on unabated emissions to the degree that they affect the plants setting the price for power. For example, in the integrated 1990-7% 2005 case, CO_2 emission allowance costs represent roughly 69 percent of the change in the total cost of service—all the costs incurred by power suppliers to meet the demand for electricity, including fuel costs, operating and maintenance costs, capital investment costs, and emission allowance costs—in 2010 and 2020.

The allowance prices for NO_x, SO_2, and CO_2 are projected to vary considerably across the analysis cases (Table 11). The differences result from the levels of and interrelationships among the three emission caps in each case. The prices for each emission allowance are inextricably linked, and caution should be used in trying to discern their individual impacts. The linkages among them can be seen by comparing the projections in the reference case and the NO_x, SO_2, and CO_2 cap cases with those in the various integrated cases. For example, NO_x allowances prices in 2010 are projected to be $2,254 per ton in the reference case, $1,081 per ton in the NO_x 2005 case, $2,467 in the SO_2 2005 case, and $0 to $85 per ton in the CO_2 cap and integrated cases (including sensitivity cases).

It may seem surprising that the projected NO_x allowance price is higher in the reference case than in the NO_x cap case with a relatively stringent limit. This occurs because the reference case cap is applied only to plants in 19 States over a 5-month summer season, and, at the margin, it is more expensive to meet than the nationwide annual cap imposed in the NO_x cap cases. The relatively high NO_x allowance prices projected in the SO_2 cap cases also occur partially because of the 19-State, 5-month season cap imposed. These cases assume the same limits that are imposed in the reference case. The NO_x allowance prices in the SO_2 cap cases are slightly higher than those in the reference case, because efforts to meet the stringent SO_2 cap lead to changes in the way particular plants are operated, increasing the cost of NO_x emission reduction options. The low NO_x allowance prices projected in the CO_2 cap and integrated cases, especially in the later years of the forecast, occur because efforts to meet the CO_2 emission caps in these cases lead to substantial reductions in NO_x emissions.

Similar linkages can be seen in the projections of SO_2 allowance prices. The reference, NO_x cap, and CO_2 cap cases all incorporate the CAAA90 8.95 million ton national SO_2 emission cap promulgated. The projected SO_2 allowance prices in the reference and NO_x cap cases are similar. However, when a CO_2 cap is incorporated with the 8.95 million ton SO_2 cap, as in the CO_2 cap cases, efforts expected to be made to meet the CO_2 cap enable

Table 11. Projected Power Plant Emissions Allowance Prices, 2005-2020
(1999 Dollars per Ton and 1999 Dollars per Metric Ton Carbon Equivalent)

	Allowance Prices											
	NO_x				SO_2				CO_2			
Analysis Case	2005	2008	2010	2020	2005	2008	2010	2020	2005	2008	2010	2020
Reference	2,374	1,296	2,254	2,071	178	173	170	246	NA	NA	NA	NA
NO_x Cap Cases												
NO_x 2005	1,196	769	1,081	1,098	178	173	181	247	NA	NA	NA	NA
NO_x 2008	1,102	1,136	1,189	1,225	178	173	182	247	NA	NA	NA	NA
SO_2 Cap Cases												
SO_2 2005	2,419	2,409	2,467	3,164	303	332	735	1,084	NA	NA	NA	NA
SO_2 2008	2,475	1,847	2,320	2,818	107	303	283	1,125	NA	NA	NA	NA
SO_2 Sensitivity	2,484	1,703	2,034	2,104	281	307	300	382	NA	NA	NA	NA
CO_2 Cap Cases												
CO_2 1990-7% 2005	1,981	0	0	0	0	0	0	0	120	148	143	141
CO_2 1990-7% 2008	2,114	0	0	0	21	0	0	0	79	108	139	139
CO_2 Sensitivity	2,191	79	85	0	4	10	5	0	95	95	102	112
Integrated Cases												
Integrated 2005	1,000	141	0	0	247	231	221	162	115	112	114	113
Integrated 1990-7% 2005	969	0	0	0	201	192	226	99	113	138	134	130
Integrated 2008	888	936	0	0	61	254	213	165	71	102	108	116
Integrated 1990-7% 2008	801	876	0	0	74	168	141	95	71	87	126	129
Integrated Sensitivity	2,253	27	64	37	104	103	101	51	94	97	101	115

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

the power sector to meet the SO_2 emissions limits without additional work. As a result, the SO_2 allowance price in these cases falls to zero. The SO_2 cap and integrated cases (excluding the sensitivity cases) incorporate the 3.27 million ton cap examined in this analysis. In the SO_2 cap cases the more stringent standard is projected to lead to much higher SO_2 allowance prices, exceeding $700 per ton in 2010 and $1,100 per ton in 2020. When the 3.27 million ton SO_2 cap is combined with a CO_2 cap in the integrated cases, however, the SO_2 allowance price is expected to range between $141 and $226 per ton in 2010, much lower than in the SO_2 cap cases.

The CO_2 allowance price also varies, but to a smaller degree, when examined with the reference case NO_x and SO_2 provisions than when examined with the more stringent NO_x and SO_2 provisions analyzed in the integrated cases. For example, the CO_2 allowance price (given in dollars per metric ton carbon equivalent) in 2010 in the CO_2 1990-7% 2005 case is projected to be $143; however, in the integrated 1990-7% 2005 case, which incorporates the same CO_2 cap, it is projected to reach only $134 per metric ton. The requirement to also reduce NO_x and SO_2 emissions in the integrated cases slightly reduces the incremental cost of reducing CO_2 emissions.

A coordinated approach to reducing power sector NO_x, SO_2, and CO_2 emissions in the integrated cases should lead to lower overall costs than one for each of the emissions individually. As shown in this report, the compliance decisions that are projected when the NO_x and SO_2 caps are examined alone are very different from those expected when the three emission caps are combined. The exact savings depend on the particular scenarios analyzed. The key factor is the timing of the NO_x and SO_2 caps relative to the timing of the CO_2 cap. On one hand, if NO_x and SO_2 caps were imposed and then followed shortly by a CO_2 cap that was unexpected, substantial investments could be made in control equipment that would later prove uneconomical. On the other hand, if the CO_2 cap preceded the NO_x and SO_2 caps, the potential for uneconomical investments in control equipment would appear to be small.

A rough measure of the maximum potential for savings in a coordinated approach would be to compare the cost increase projected in an integrated case with the sum of the cost increases projected in the cases that impose each emission cap individually. Table 12 shows the calculations for the integrated 1990-7% 2005 case and the standalone NO_x 2005, SO_2 2005, and CO_2 1990-7% 2005 cases with and without allowance fees. The values without allowance fees (often referred to as "resource costs") represent just the expected increases in expenditures on fuel and other operating costs and the increased investments in new emission control equipment and new capacity. The projected savings in total resource costs are higher in the early years—as much as $6 billion in 2006—because in the integrated cases the expected investments in control equipment to remove NO_x and SO_2 to meet the respective 2005 caps are less than those expected in the NO_x and SO_2 cap cases. After 2015, the projected savings in total resource costs are small. In the integrated case many of the plants to which controls might have been added are expected to be retired.

As might be expected, the impact of the assumed CO_2 emission caps on electricity prices is projected to be fairly sensitive to the stringency of the caps (Figure 12). For example, in the CO_2 1990-7% 2005 case, the price of electricity in 2010 is projected to be 42 percent above the reference case level. In the less stringent CO_2 sensitivity case, however, the difference is expected to be 29 percent. Similarly, average electricity prices in 2010 in the integrated 1990-7% 2005 case are projected to be 43 percent higher than projected in the reference case level, but in the integrated sensitivity case they are projected to be 30 percent above the reference case projection.

The higher electricity prices projected in the analysis cases, particularly those with CO_2 caps, lead to lower total consumption of electricity. In response to higher projected prices, consumers are expected to make efforts to reduce their electricity use (Figure 13). Efforts may include switching to other fuels, buying more efficient appliances and equipment, and simply reducing the usage of electricity-using devices. The projected small price changes in the NO_x and SO_2 cap cases are expected to lead to little change in consumer electricity consumption. In these cases, total electricity sales in 2010 are projected to be only slightly lower than in the reference case. The impact on consumer electricity use is expected to be much larger in the cases with CO_2 emission caps, where the demand for electricity is expected to be between 5.8 and 7.6 percent (241 to 314 billion kilowatthours) below the reference case in 2010.[15]

In some cases, consumers' efforts to reduce their electricity consumption could partially offset the CO_2 emissions reductions in the electricity sector. For example, if an industrial consumer reduces electricity consumption by using more coal, oil, or gas on site, the CO_2 emissions reductions that occur in the power sector could be partially offset by increases in the industrial sector. "Leakage," as it is commonly called, is always a possibility when emission caps are imposed on one sector of the economy while other sectors are not similarly constrained. The degree to which it occurs will depend on several factors, including the substitutability of other fuels for electricity in the residential, commercial, and industrial sectors and the overall economic impacts of

[15]The tendency of consumers to switch from electricity to natural gas is expected to be reduced somewhat by the increase in gas prices that would result from increased use of natural gas by eleectricity generators to meet the emission targets.

Table 12. Projected Changes from Reference Case Estimate of Total Costs of Service for U.S. Electricity Generators, 2005-2015
(Billion 1999 Dollars)

Year	NO_x 2005 Case	SO_2 2005 Case	CO_2 1990-7% 2005 Case	Sum: NO_x 2005, SO_2 2005, and CO_2 1990-7% 2005 Cases	Integrated 1990-7% Case: Projected Costs	Integrated 1990-7% Case: Projected Savings
Including Allowance Costs in Total Costs						
2005	3	3	77	82	77	5
2006	4	3	70	77	68	9
2007	3	4	77	83	74	9
2008	3	3	89	96	87	8
2009	2	4	86	92	88	5
2010	2	4	88	94	86	9
2011	2	4	87	94	84	9
2012	3	5	90	97	87	11
2013	2	3	89	94	89	5
2014	3	3	89	96	87	9
2015	2	3	85	90	86	5
Excluding Allowance Costs from Total Costs						
2005	2	3	21	26	24	2
2006	3	4	20	28	22	6
2007	2	4	22	28	23	5
2008	3	3	27	32	28	4
2009	2	3	26	30	28	2
2010	2	3	28	33	28	5
2011	1	3	28	32	29	3
2012	1	3	29	34	29	5
2013	1	2	30	33	30	3
2014	2	2	31	36	31	4
2015	1	2	29	33	32	1

Note: Totals may not equal sum of components due to independent rounding.

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

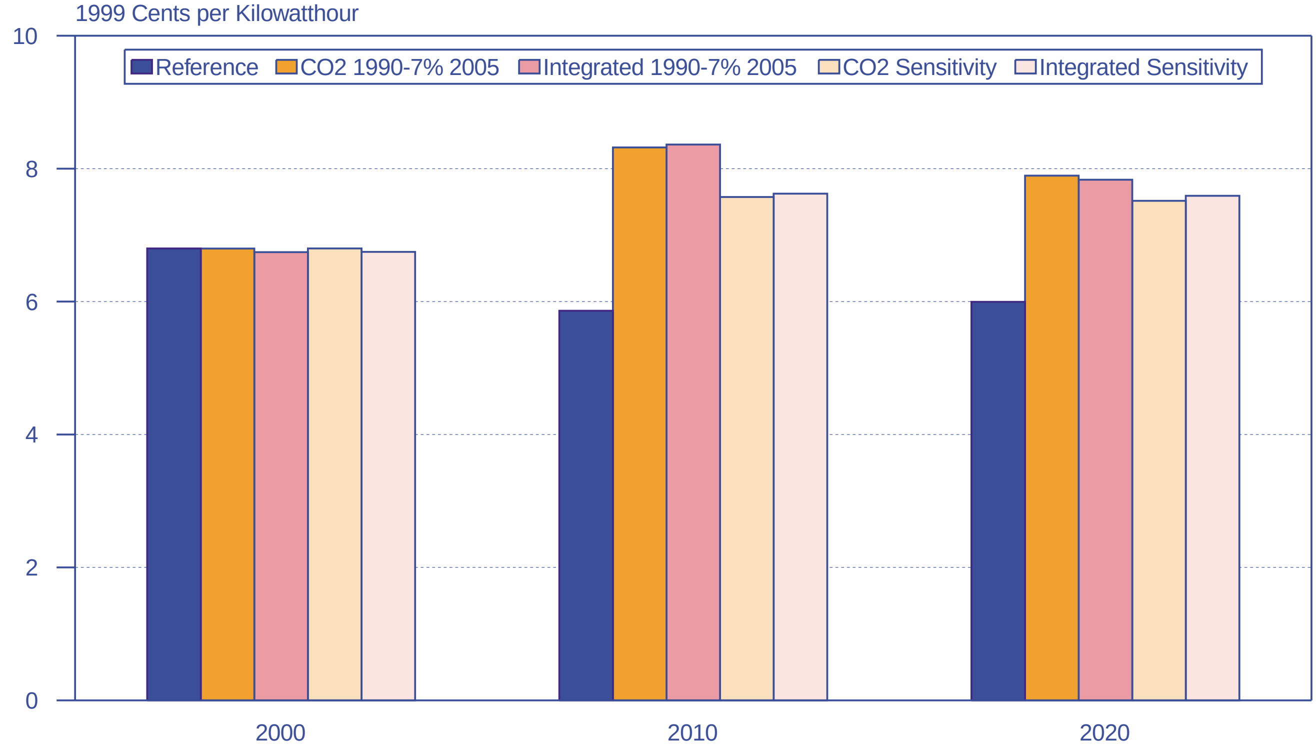
higher electricity and natural gas prices and lower coal prices resulting from the electricity sector emissions caps.

As mentioned above, in this analysis projected higher electricity prices in the cases with CO_2 caps are expected to cause consumers to reduce their electricity consumption. However, end-use consumers are also projected to face higher natural gas prices as electricity producers turn to gas to reduce their CO_2 emissions. The net effect of these price changes is a slight reduction in non-electricity sector CO_2 emissions relative to the reference case. In other words, leakage of CO_2 emissions is negative rather than positive. The decline in coal prices projected in the cases with CO_2 caps is projected to be relatively small and is not expected to increase the use of coal in the non-electricity sectors. Coal use is virtually nonexistent in the residential and commercial sectors, and its use in the industrial sector is limited. In total, U.S. energy-related CO_2 emissions are projected to be 249 million metric tons carbon equivalent below the reference case level in 2010 and 333 million metric tons below the reference case level in 2020 in the 1990-7% 2005 case. Even after those changes, however, total U.S. energy-related CO_2 emissions are projected to remain 317 and 462 million metric tons above the target set in the Kyoto Protocol in 2010 and 2020, respectively.

Overall, the Nation's total electricity bill is expected to be higher in the cases with CO_2 caps than in the reference case (Figure 14). The change is smaller in percentage terms than the change in electricity prices because of the projected reduction in electricity usage just discussed. In percentage terms, in 2010 the Nation's annual electricity bill is projected to range between 25 and 32 percent higher in the cases with CO_2 caps than in the reference case. Because of the vast size of the electricity market, these percentage changes translate to between $60 billion and $77 billion per year.

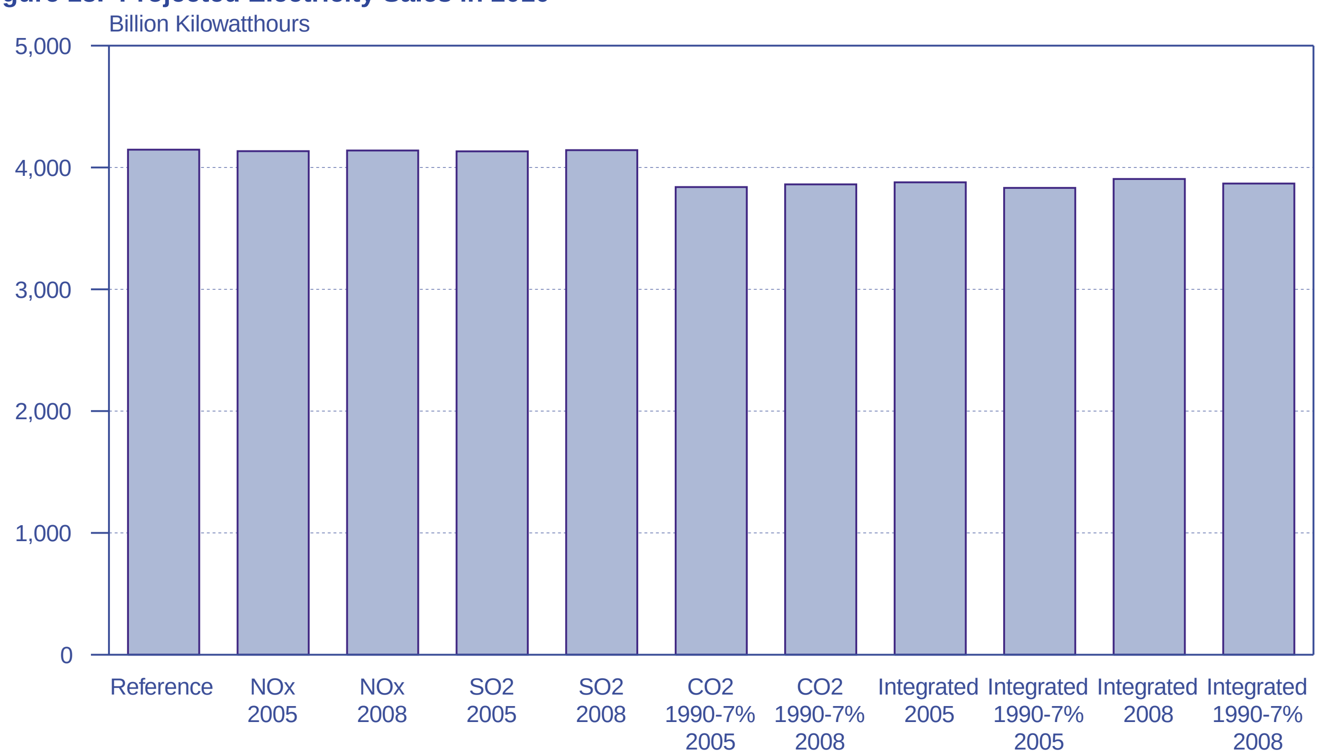
For the average household the projected increases in electricity prices could have a significant impact on annual electricity bills (Figure 15). In the reference case, the annual electricity bill for the average single-family home is estimated to be just over $881 in 1999. It is expected to increase over time, reaching $993 by 2020. In the integrated 1990-7% 2005 case, the annual electricity bill for the average single-family home is estimated to be $1,128 in 2010, or $201 higher than projected in the reference case.

Figure 12. Projected Electricity Prices, 2000, 2010, and 2020



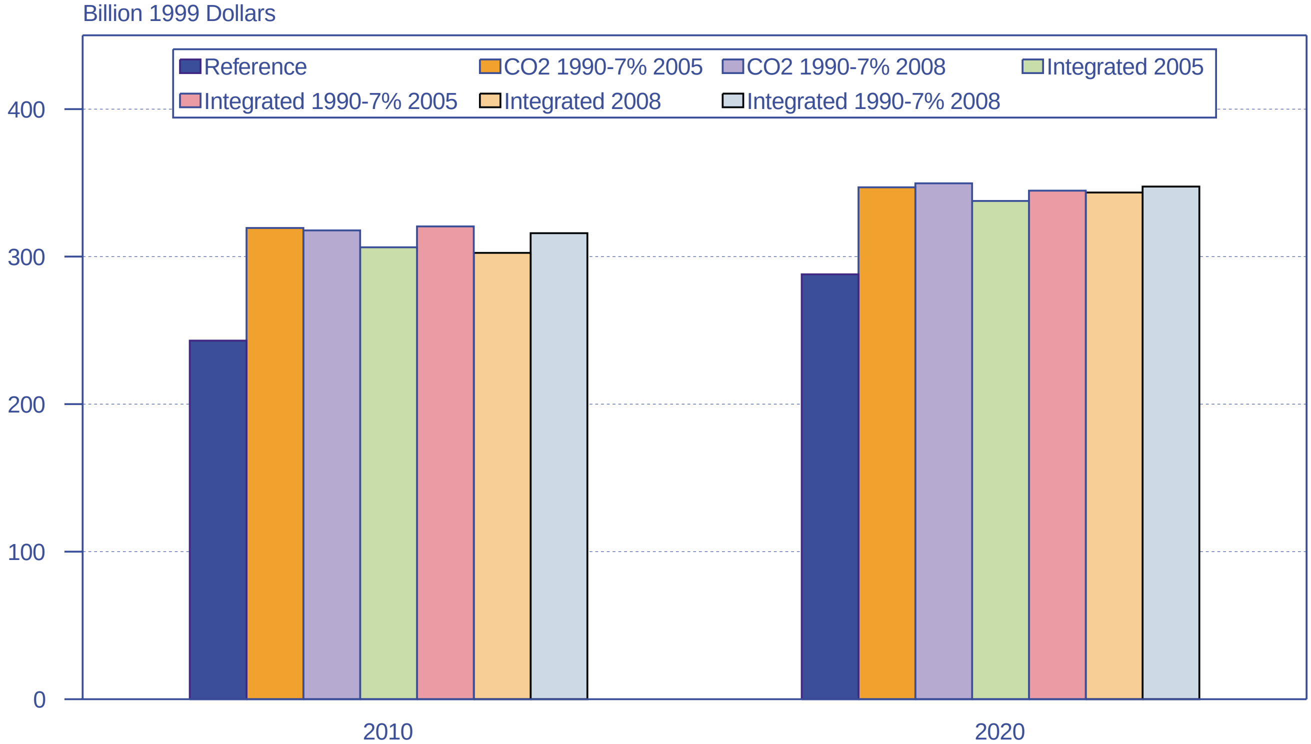
Source: National Energy Modeling System, runs MCBASE.D121300A, FDC7B05.D121300A, FDC7B05H.D121300A, FDP7B05.D121300B, and FDP7B05H.D121300A.

Figure 13. Projected Electricity Sales in 2010



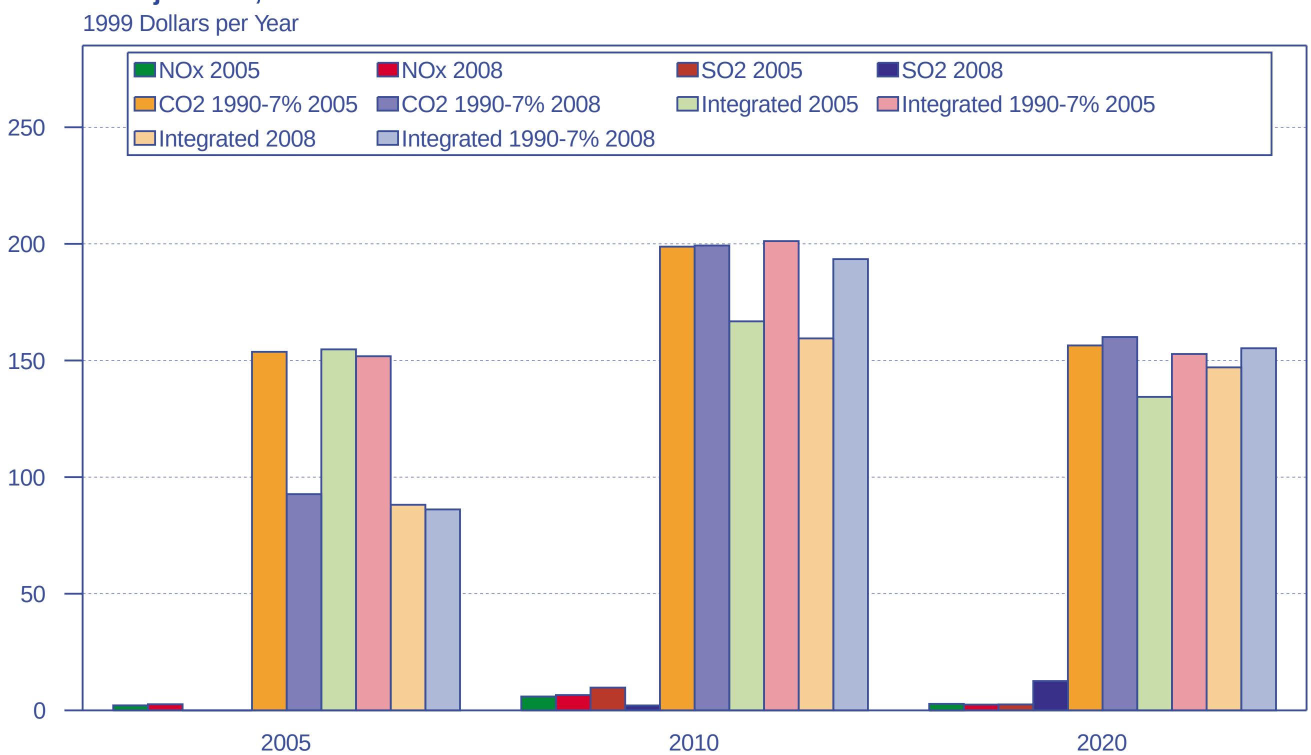
Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Figure 14. Total Projected U.S. Annual Electricity Bill, 2010 and 2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.

Figure 15. Average Projected Changes in Annual Household Electricity Bills Relative to Reference Case Projections, 2005-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05. D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

Summary

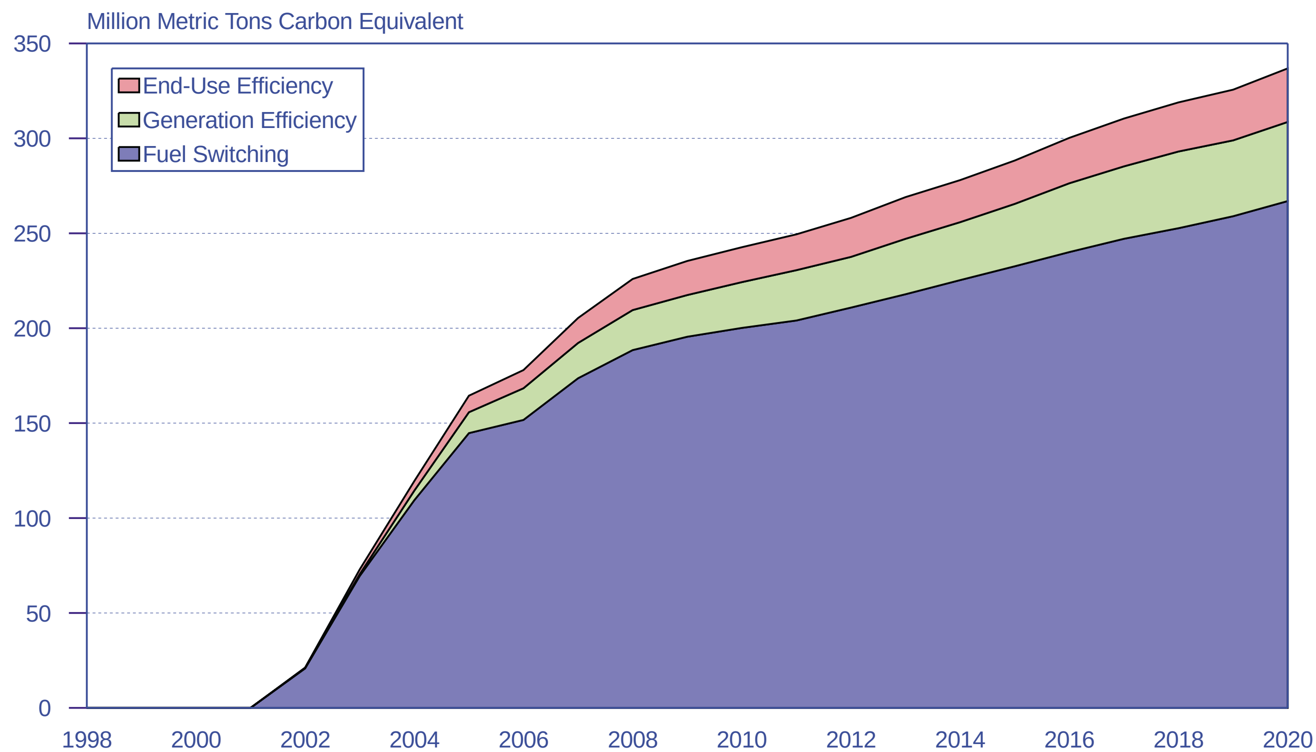
Projected Impacts

Imposing NO_x, SO_2, and CO_2 caps on the power sector is expected to have impacts on all aspects of the electricity generation sector, including capacity expansion and retirement decisions, generation by fuel, and electricity prices. A key result is that the compliance decisions made by power plant operators could be very different if the various emissions caps were imposed together or one at a time on different schedules. Power plant owners would be expected to rely heavily on investments in emission control technologies to comply with the NO_x and SO_2 caps if they were introduced individually or well in advance of a CO_2 cap; but if the NO_x, SO_2, and CO_2 caps were combined, heavy investments in NO_x and SO_2 emission control equipment are not expected to be cost-effective. Rather, many of the coal-fired power plants where such equipment might have been added are projected to be retired if a CO_2 cap is imposed.

When the three emission caps are assumed to be imposed in concert, efforts to comply with the CO_2 cap are projected to have the most significant effect, as can seen by comparing the results for the CO_2 cap and integrated cases. The projected impacts on capacity expansion and retirement, fuel use, and consumer electricity prices are similar in the CO_2 cap and integrated cases. In particular, the most significant increases in consumer electricity prices relative to the reference case projections are seen in the analysis cases that include a CO_2 cap. In the cases without a CO_2 cap, electricity prices are not projected to be more than a few percentage points above the reference case level in 2010 and 2020. In these cases some of the costs associated with adding NO_x and SO_2 control equipment are not expected to be passed on to consumers; rather, they would result in reduced profits for the plant owners who made the investments. In cases with a CO_2 emission cap, electricity prices are expected to be significantly higher. For example, in the integrated 1990-7% 2005 case, the projected electricity prices are 43 percent higher in 2010 and 31 percent higher in 2020 than those projected in the reference case.

Power plant operators and consumers are expected to contribute to the reductions in CO_2 emissions required in the cases with CO_2 caps. Power plant operators are projected to make a dramatic switch from relatively carbon-intensive coal to less carbon-intensive natural gas and carbon-free renewables (Figure 16). The plants built to replace retiring coal plants are also expected to be more efficient, further reducing their CO_2 output per kilowatthour of generation. Consumers are expected to react to higher electricity prices by reducing their consumption of electricity in part through increased investments in more efficient end-use equipment.

Figure 16. Projected Sources of Electricity Sector Reductions in Carbon Dioxide Emissions in the Integrated 1990-7% 2005 Case, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A and FDP7B05.D121300B.

Uncertainty

As with all projections, there is considerable uncertainty in the results of this analysis. Among the key factors that influence the results are the significance of the changes; uncertainty about future fuel prices, particularly for natural gas; changes in policies over the next 10 to 20 years; potential cost and performance improvements in emission control and generating technologies; the ability of the various energy markets to make the adjustments that would be needed over the next 5 to 8 years; the impacts of the ongoing changes in the structure of electricity markets; and the potential impacts of Hg emission regulations. To comply with the emission caps—particularly the CO_2 cap—examined in this report, power suppliers are projected to have to make a rapid shift away from coal-fired plants, which have been the predominant source of electric power in the United States for more than 50 years.

While this analysis suggests that electricity suppliers will be able to move to natural gas and renewable fuels, the potential impacts of a shift of this size, especially over a short time period, are difficult to predict. There is no history to use as a guide for a change of such magnitude. During the transition period there could be significant volatility in the market-based prices of emission allowances and in the wholesale and, potentially, retail prices of electricity. In addition, planning, siting, obtaining environmental permits for, and building the amount of new gas-fired capacity projected to be needed, as well as developing the natural gas resources that would be required to supply them, could be difficult in the time frame assumed here.

Because new natural-gas-fired power plants are expected to be the most important compliance option in the CO_2 cap and integrated cases, natural gas prices are critical in determining the costs of meeting the emission caps. Lower gas prices than those projected in this analysis would reduce the overall compliance costs, and higher prices would increase them.

In the past, when new emissions regulations were imposed, they stimulated research and development that lowered the costs and improved the performance of new emission control equipment and low-emission generating technologies. Because the assumed caps in this analysis would have to be met by 2005 or 2008, however, there would be little time to bring new or improved technologies to the market. Given the normal pace of environmental regulations and compliance dates, the cases with 2005 dates may be unrealistic. With a later compliance date, such improvements could be important. To meet the 2005 caps, however, power plant owners probably would have to rely on currently available technology. There would not be sufficient time to install and test new approaches. In the longer term, NEMS incorporates assumed improvements in cost and performance for new generating and emission control technologies, which reduce the projected costs of complying with the caps. This can be seen by comparing projected compliance costs in 2020 with those in 2010.

The changing structure of U.S. electricity markets—specifically the reliance on competitive markets to set electricity prices—is likely to affect the way in which power suppliers respond to emission caps. It is assumed in this report that independent power producers will dominate new power plant additions, and that wholesale power will be priced competitively.

A key uncertainty with regard to competitive power markets is how consumers and product developers might respond to competitively priced electricity. One feature that has been seen in newly competitive markets is a large amount of price volatility. Because such volatility has not occurred historically, consumers (including homeowners and commercial and industrial establishments) have not invested in equipment that could reduce their exposure to higher prices. It remains to be seen whether the market will become more responsive in the future.

A subsequent EIA service report, to be issued in early 2001, will extend this analysis to examine the impacts of a power sector cap on Hg emissions. It is not possible at this time to predict the impact of the cap in the projections; however, because power sector Hg emissions come almost entirely from coal-fired plants, it is expected that controlling them will lead to higher projected operating costs for those plants. In some cases, coal-fired plants may simply be retired rather than retrofitted with the controls that would be needed.