6. Comparisons With Other Studies

Introduction

In recent years, significant analysis has been devoted to the problem of reducing individual airborne emissions from electric power plants—either greenhouse gases, of which carbon dioxide (CO_2) is the most pervasive,[29] or any of several criteria pollutants,[30] such as sulfur dioxide (SO_2)[31] and nitrogen oxides (NO_x).[32] Other studies have focused on demand-side innovations, principally in other sectors, that could alleviate power plant emissions.[33] Less attention has been directed to the problem of analyzing multi-emission reduction strategies. This chapter provides a summary of four recent studies addressing the joint reduction of SO_2, NO_x, CO_2, and mercury (Hg) emissions in some combination and compares them, where possible, with the findings of the analysis described in this report.

Over the past several years, the U.S. Environmental Protection Agency (EPA) has used the Integrated Planning Model (IPM) to analyze strategies for reducing emissions of SO_2, NO_x, CO_2, and Hg, first under the Clean Air Power Initiative in 1996 and again in 1999 after soliciting industry reaction and input.[34,35] The Electric Power Research Institute (EPRI) also took up the question of reducing SO_2, NO_x, and CO_2 emissions, examining both cost effects and long-term sustainability.[36] The Environmental Law Institute (ELI) approached the question differently, examining the economic impacts of a 50-percent reduction in coal-fired generation by 2010 using the Resources for the Future (RFF) Haiku electricity market model.[37] Although there are similarities among the studies, they were prepared with different objectives, incorporating different assumptions about emission limits and using different methodologies. As a result, comparisons among them must be made cautiously.

[29] For example, WEFA, Inc., *Global Warming: The High Cost of the Kyoto Protocol, National and State Impacts* (Eddystone, PA, 1998); H.D. Jacoby, R. Eckhaus, A.D. Ellerman, et al., "CO_2 Emission Limits: Economic Adjustments and the Distribution of Burdens," *Energy Journal*, Vol. 18, No. 3 (1997), pp. 31-58; S. Bernow et al., *America's Global Warming Solutions* (Washington, DC: World Wildlife Fund and Energy Foundation, August 1999); H. Geller, S. Bernow, and W. Dougherty, *Meeting America's Kyoto Protocol Target: Policies and Impacts* (Washington, DC: American Council for an Energy-Efficient Economy, December 1999); Congressional Budget Office, *Who Gains and Who Pays Under Carbon-Allowance Trading? The Distributional Effects of Alternative Policy Designs* (Washington, DC, June 2000).

[30] Other criteria pollutants include carbon monoxide, lead, particulate matter (PM_{10}), and volatile organic compounds.

[31] D. Burtraw and E. Mansur, "Environmental Effects of SO_2 Trading and Banking," *Environmental Science & Technology*, Vol. 33, No. 20 (October 15, 1999), p. 3489; K.K. Dhana, "A Market-Based Solution to Acid Rain: The Case of the Sulfur Dioxide (SO_2) Trading Program," *Journal of Public Policy & Marketing*, Vol. 18, No. 2 (Fall 1999), pp. 258-265; R.D. Lile, D. Bohi, and D. Burtraw, *An Assessment of the EPA's SO_2 Emission Allowance Tracking System* (Washington, DC: Resources for the Future, February 1997).

[32] U.S. Environmental Protection Agency, *Regulatory Impact Analysis for the Final Section 126 Petition Rule* (Washington, DC, December 1999); D. Burtraw, K. Palmer, and A. Paul, *The Welfare Impacts of Restructuring and Environmental Regulatory Reform in the Electric Power Sector* (Washington, DC: Resources for the Future, October 1998), preliminary version; A. Krupnick, V. McConnell, M. Cannon, T. Stoessell, and M. Batz, *Cost-Effective NO_x Control in the Eastern United States* (Washington, DC: Resources for the Future, April 2000).

[33] Interlaboratory Working Group, *Scenarios for a Clean Energy Future*, ORNL/CON-476 and LBNL-44029 (Oak Ridge, TN: Oak Ridge National Laboratory; Berkeley, CA: Lawrence Berkeley National Laboratory, November 2000); J. Koomey, R. Richey, S. Laitner, R. Markel, and C. Marnay, *Technology and Greenhouse Gas Emissions: An Integrated Scenario Analysis Using the LBNL-NEMS Model*, LBNL-42054 (Berkeley, CA: Lawrence Berkeley National Laboratory September 1998); Alliance to Save Energy, American Council for an Energy-Efficient Economy, Natural Resources Defense Council, Tellus Institute, and Union of Concerned Scientists, *Energy Innovations 1997: A Prosperous Path to a Clean Environment* (Washington, DC, June 1997). Modeling demand-side reductions in the end-use sectors can produce dramatic results. The *Clean Energy Future* report projects carbon reductions similar to those identified here, with a carbon allowance fee of $50 per ton and limited costs to consumers. Among the assumptions for the power sector necessary to achieve this result, however, are extension of the 1.5 cents per kilowatthour production tax credit through 2004 and capital costs for wind technology of $611 per kilowatt (as compared with $993 per kilowatt in EIA's analysis). Further, other policies in the study serve to reduce projected energy demand, so that energy consumption in 2020 is projected to be about 95 quadrillion Btu, roughly equivalent to maintaining 1998 levels of consumption for the next 20 years.

[34] U.S. Environmental Protection Agency, *EPA's Clean Air Power Initiative* (Washington, DC, October 1996).

[35] U.S. Environmental Protection Agency, *Analysis of Emissions Reduction Options for the Electric Power Industry* (Washington, DC, March 1999), web site www.epa.gov/capi/multipol/mercury.htm.

[36] Electric Power Research Institute, *Energy-Environment Policy Integration and Coordination Study*, TR-1000097 (Palo Alto, CA, 2000).

[37] Environmental Law Institute, *Cleaner Power: The Benefits and Costs of Moving from Coal to Natural Gas Power Generation* (Washington, DC, November 2000).

The studies discussed here all contain extensive analysis of impacts on the electricity generation sector.[38] Among the key variables examined are changes in capacity type, changes in fuel use and the consequent fuel price responses, changes in the overall generation mix, responses of renewable technologies, and SO_2 allowance prices and carbon allowance fees. However, because the studies assume caps of different levels, on different emissions, over different time periods, and starting from different baselines, straightforward comparisons among the studies are difficult.

In this chapter, the reference cases from the studies are compared, and two of the integrated cases from the EIA analysis are compared with integrated cases from the EPA, EPRI, and ELI studies. Generally speaking, all the studies introduce various emission caps. Beyond that immediate similarity, there are differences in the assumptions made and in the methodologies and, to a lesser extent, the initial baselines used that render highly detailed comparisons difficult. These include:

- **Integrated versus nonintegrated models.** The models used in the studies by EIA, EPRI, EPA, and ELI all have detailed representations of the electricity sector, but details in the representation of other sectors of the energy economy and their interaction with the electricity sector differ. For example, the EIA's National Energy Modeling System (NEMS) endogenously calculates consumer demand for each fuel and the prices at which the fuels are expected to be supplied in order to meet demand. When changes in assumptions (such as adding pollution control equipment or switching fuels to reduce emissions) alter fuel production costs, the projections of fuel prices and consumers' responses to them are recalculated by the model. Because the EPRI analysis used NEMS through 2020 it shares this behavior. In the EPA analysis, electricity demand and a battery of fuel supply curves are determined exogenously. When emission caps are imposed on the electricity generation sector, there are shifts in the demand for different fuels, resulting in different fuel prices (e.g., the wellhead price for natural gas) in the reference and integrated cases. Unlike in the NEMS model, however, fuel supply and demand for the electricity generation sector are not endogenously linked in an integrated system in the EPA model. Thus, the EPA analysis does not include a fuel price response to higher demand or a decline in electricity demand in response to higher prices. The Haiku model contains endogenous electricity demand that responds to changes in prices and upward-sloping fuel supply curves for natural gas and coal.

- **Treatment of nuclear power.** Because nuclear generating units produce no emissions, assumptions about their ability to remain in the generation mix through 2020 can play a key role. In NEMS, maintenance versus retirement decisions for nuclear plants are evaluated endogenously. NEMS weighs the costs of maintaining each nuclear plant against the costs of building a new plant to replace it. When the costs of new fossil plants increase (as in the cases with CO_2 caps in this analysis), the economics of maintaining existing nuclear plants improves, and fewer are retired. In the EPA analysis, nuclear capacity is assumed to decrease from 87 gigawatts in 2005 to 50 gigawatts in 2020. Like NEMS, Haiku has an endogenous nuclear retirement algorithm.

- **Knowledge and ability to react to changing market conditions, including lead time.** Decisionmakers, as represented in models, may have perfect knowledge or very little foresight. As an integrated model, NEMS incorporates macroeconomic feedback in response to the electric power industry's response to emission caps. The model used by EPA does not incorporate this type of response mechanism.

- **Treatment of Emission Caps:** Both the IPM and NEMS are able to model emission caps directly, allowing investments in controls to be made ahead of the control date. The explicit representation also enables the projected allowance prices for each controlled pollutant to be obtained as direct model outputs. Haiku has the ability to model such caps, but the ELI study employs a cap on total coal-fired generation.

- **Representation of Emission Control Technologies**: The IPM, NEMS, and Haiku models allow power plants to choose from an array of control technologies for reducing SO_2 and NO_x; however, the IPM includes a broader array of control technologies than represented in either NEMS or Haiku.

The analyses reviewed here also have some important similarities, the most important being a similar representation of available generating technologies and emission control technologies. All the models can choose to introduce new technologies such as integrated coal gasification units, gas turbines, advanced combined-cycle units, and renewable technologies. The models respond to SO_2 constraints in similar ways, either by means of adding a scrubber retrofit, switching fuels, or economic

[38] The NEMS model does not analyze or forecast health benefits. One recent estimate projected direct health benefits stemming from the Clean Air Act Amendments of $110 billion in 2010 (1999 dollars). See U.S. Environmental Protection Agency, *The Benefits and Costs of the Clean Air Act 1990 to 2010,* EPA-410-R-99-001 (Washington, DC, November 1999).

retirement. NO_x controls may be introduced during the combustion phase or through post-combustion technologies.[39] CO_2 emissions are constrained through a carbon cap.[40] Finally, all the models show similar starting points for key electric power industry statistics, including total generating capacity, coal-fired capacity, electricity demand, and baseline projections for CO_2 emissions from the electric power industry.

Summary of Studies

EPA's 1999 Emission Reduction Analysis

EPA's Clean Air Power Initiative (CAPI), which began in 1995, was intended to improve air pollution control efforts by involving the power generating industry in developing and analyzing alternative approaches to reducing three major emissions: SO_2, NO_x, and, potentially, Hg. The analysis used the IPM, a detailed model of the electric power industry in which plant operators react to alternative levels of pollution controls. CAPI proposed a "cap and trade" approach for the emissions and modeled the proposed reductions on a national scale. Initial NO_x caps were set for both summer and winter beginning in 2000, and the initial rate-based caps were then reduced to the most stringent levels modeled, 0.15 pounds per million Btu in 2005. At the same time, SO_2 was reduced in 2010 by lowering the current Clean Air Act Amendments of 1990 (CAAA90) Title IV SO_2 allowance cap by 50 percent, to about 4.5 million tons per year. A cap on Hg emissions was set in 2000 to the amount expected in 2000, and then lowered in 2005 by 50 percent, and again in 2010 by another 50 percent (total 75-percent reduction). The results of the initial analysis effort were published in 1996, and the EPA invited interested parties to comment.

EPA's Office of Air and Radiation responded to comments received and modified CAPI in a new series of modeling efforts in 1999. The emissions analyzed were SO_2, NO_x, CO_2, and Hg. Unlike the 1996 study, NO_x emissions were not reduced beyond then-current statutory requirements, such as Phases I and II of the Title IV Acid Rain program or the NO_x SIP (State Implementation Plan) Call, under which 22 States[41] and the District of Columbia must reduce NO_x emissions by 2004. Hypothetical emission caps were developed for each of the remaining emissions. This study allowed a variety of compliance options to meet the emission caps, including fuel switching, repowering, retrofitting or retiring units, and adjusting dispatch.

EPA's 1999 analysis modeled reductions of the emissions singly and, in certain combinations, jointly. SO_2 emissions were reduced from current levels to four alternative levels (by 40 percent, 45 percent, 50 percent, and 55 percent) beginning in 2007, and the targets were assumed to be met in 2010. The analysis cases used the cap and trade approach, with banking of allowances permitted from 2005 to 2007.

Two alternative cases in the EPA analysis examined CO_2 reduction options. The first provided the power industry with 463 million metric tons carbon equivalent per year in allowances and assumed that the industry would find it most economical to purchase an additional 104 million metric tons carbon equivalent in allowances on the international market, effectively capping emissions from electricity generators at 567 million metric tons carbon equivalent per year. The second CO_2 alternative introduced high efficiency assumptions, whereby electricity demand was assumed to be 15 percent lower in 2010 than projected by the industry. Demand was reduced by 1.5 percent annually during the years 2000 to 2010 and by 1 percent annually for the next 10 years. The effective CO_2 emission cap remained at 463 million metric tons carbon equivalent, and the industry was assumed to find it most economical to purchase additional allowances of 52 million metric tons carbon equivalent, yielding a domestic carbon emission cap of 515 million metric tons carbon equivalent for electricity generators.

Costs for controlling Hg emissions were analyzed by assuming that coal-fired generators would install maximum achievable control technology (MACT) in conjunction with either the 50-percent SO_2 reduction or the 515 million metric tons carbon equivalent CO_2 / high efficiency scenario. Two cases considered SO_2 and CO_2 reductions jointly: (1) the 50-percent SO_2 reduction with a CO_2 level of 567 million metric tons carbon equivalent, and (2) the 50-percent SO_2 reduction in combination with a CO_2 level of 515 million metric tons carbon equivalent and high efficiency constraints assumed to reduce demand by 15 percent in 2010.

A key finding of EPA's 1999 analysis was that a joint SO_2-CO_2 reduction strategy would cost the industry less than undertaking the reduction strategies separately. In 2010, reducing SO_2 emissions by 50 percent of the base projection was estimated to cost about $2.5 billion (1990 dollars), and meeting the CO_2 cap of 515 million metric tons carbon equivalent was estimated to cost about $2 billion, with the additional costs resulting from the

[39]Selective catalytic or noncatalytic reduction.

[40]The ELI study reduces CO_2 emissions indirectly by capping coal-fired generation.

[41]In the EIA analysis cases, the SIP Call modeled applies to 19 States, because since it was first proposed, facilities in Wisconsin have been removed from the program, and the caps on facilities in Missouri and Georgia are under review.

installation of scrubbers, introduction of natural gas combined-cycle technology, and additional dispatch of gas-fired units. Joint reduction lowered the projected aggregate costs to $3.6 billion, or by about 20 percent.[42] The EPA analysis concluded that the industry, when faced with significant CO_2 constraints over and above SO_2 caps, would avoid costly scrubber retrofits and turn to natural gas generation in order to meet SO_2 constraints.

EPRI's Energy-Environment Policy Integration and Coordination Study

The timing and coordination of multiple pollution reduction strategies was the primary focus of EPRI's E-EPIC analysis. Observing that current policy requires power generators to reduce NO_x and SO_2 emissions in the short term, while the Kyoto Protocol calls for significant reductions in CO_2 emissions over the period 2008-2012, EPRI suggested that two key questions should be addressed. First, would the large investments needed to meet the short-term NO_x and SO_2 reductions become "stranded" (unproductive) in the event that additional CO_2 reductions were to be later stipulated? Second, would the combined effects of sequential emission reduction policies lead to significant increases in the price of electricity and other distortions in the national energy system over the longer term to 2050?

EPRI used the NEMS model for the years through 2020 and then extended the NEMS Electricity Market Module to 2050, using other econometric models for projecting energy consumption, prices, and CO_2 emissions. In addition to a reference case,[43] EPRI developed a Current Policy Direction case. Modeling recent proposals addressing NO_x, particulate matter, and CO_2, the Current Policy Direction case imposed a summer NO_x reduction of 85 percent below 1990 levels in 22 States, a subsequent 50-percent reduction in SO_2 emissions by 2007, and a CO_2 emissions target of 9 percent above 1990 levels that would be phased in from 2005 through 2008.[44] In contrast, EPRI's third scenario, the "Carbon Glide Path to 2030" assumed no further NO_x or SO_2 reductions beyond current policy and imposed a gradual CO_2 reduction strategy beginning in 2005, increasing gradually to 2030, resulting in cumulative CO_2 emissions by 2050 that would be the same as in the 9 percent above 1990 case. As such, the Carbon Glide Path did not directly examine the effects of multiple emission reduction strategies.

The conclusions reached in EPRI's E-EPIC analysis differ from those of EPA's 1999 analysis. In the E-EPIC Current Policy Direction case, two-thirds of coal-fired capacity would be retired by 2020, and the coal share of generation would drop from a 2000 level of 55 percent to less than 10 percent by 2020. Nearly 500 gigawatts of gas-fired generating capacity would be added by 2020, with the gas share of total generation rising from 15 percent in 2000 to 60 percent by 2020. Although E-EPIC was tacit on total compliance costs, the study concluded that investment in initial compliance with proposed reductions for SO_2 in the short term would become stranded over the mid-term if CO_2 constraints were subsequently introduced. The study implied that this "inefficiency" could be costly to the electric power industry, and consequently to consumers, both in the short term and in the long term.

Recent Work: "Cleaner Power" Studies

In a recent report issued by Harvard University's John F. Kennedy School, Lee and Verma examined the possible effects of an integrated strategy of emissions reduction in the Midwest.[45] The report identified factors and quantified costs needed to induce coal-fired electricity generators in the Midwest to switch voluntarily from reliance on coal to greater use of natural gas. The authors assumed that coal plants in that region currently operate at just over half the capital and operating cost of a new gas-fired facility. Although the analysis did not cap emissions at specific levels and examined only the rate at which repowering from coal to gas might be induced, the authors reached several conclusions relevant to the EIA, EPA, and EPRI analyses. Their report concluded that the costs associated with reducing NO_x, SO_2, and particulate matter were not high enough to lead to retirements of Midwest coal plants in favor of new natural gas plants. Only the introduction of moderate carbon allowance fees in their analysis made significant amounts of gas-fired generation more attractive than coal-fired generation.

[42]The IPM calculates total cost as a total resource cost, thereby excluding allowance costs. EIA's analysis in 2010 for the most stringent integrated case includes about $58 billion for purchases of emission allowances in the estimated total compliance cost of $86 billion (in 1999 dollars). Higher projected prices for natural gas account for much of the remaining difference between the EPA and EIA estimates of total compliance costs.

[43]EPRI used the reference case from the EIA's *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998), NEMS run AEO99B.D100198A. The case incorporated all environmental regulations in effect as of mid-1998, including Phase II of the Title IV Acid Rain program and EPA's proposed SIP Call summer NO_x reductions for 22 States and the District of Columbia.

[44]EPRI assumed that the remainder of the Kyoto Protocol CO_2 reductions would be met through international carbon permit trading and sequestration. The 9 percent above 1990 level implies CO_2 emissions of about 1,462 million metric tons carbon equivalent in 2010, of which about 409 million metric tons carbon equivalent would be attributable to the electricity generation sector.

[45]H. Lee and S.K. Verma, "Coal or Gas: The Cost of Cleaner Power in the Midwest," BCSIA Discussion Paper 2000-08, ENRP Discussion Paper E-2000-08 (Kennedy School of Government, Harvard University, June 2000).

In order to analyze the rate of conversion from coal to gas, the authors first estimated the marginal cost of abatement for SO_2 and the average abatement costs for NO_x, particulates, and Hg, arriving at a total cost for conventional pollution abatement of about 1 cent per kilowatthour.[46] Assuming a long-term natural gas price of $2.50 per thousand cubic feet, they concluded that a carbon allowance fee of $60 to $70 per ton would prompt about two-thirds of the coal capacity[47] in the Midwest to shift to gas-fired generation. When more favorable gas prices of $2.00 per thousand cubic feet was assumed, a carbon fee between $20 and $30 per ton was expected to induce a two-thirds shift. Gas prices of $3.00 per thousand cubic feet were estimated to require a carbon allowance fee near $150 per ton in order to accomplish the same shift away from coal-fired generation.[48] The authors projected that a carbon allowance fee in the range of $60 to $85 per ton would increase retail electricity prices in the Midwest by 15 to 22 percent, to a range of 10.0 to 10.7 cents per kilowatthour.

The impacts of carbon allowance fees estimated by Lee and Verma are comparable to those in EIA's analysis. In EIA's most stringent integrated case, cumulative coal retirements nationally are projected to reach 47 gigawatts by 2010, about 15 percent of current coal capacity, with a corresponding carbon allowance fee of $134 per ton and a projected gas price of $4.33 per thousand cubic feet in 2010. Lee and Verma indicate that a combination of high gas prices ($3.00 per thousand cubic feet) and efficient conventional coal retrofits would force the conversion of 21 to 30 percent of coal-fired generating resources,[49] indicating a carbon allowance fee between $120 and $130 per ton.

A recent report from the Environmental Law Institute (ELI) arrived at findings similar to those of Lee and Verma. Using the Haiku Electricity Market Module[50] developed and maintained by Resources for the Future, ELI modeled a scenario in which coal-fired generation was reduced by 25 percent in 2005 and by an additional 25 percent by 2010, replacing the generation with electricity from gas-fired turbines and combined-cycle units.[51] The shift in generation produced dramatic changes in emission patterns, reducing SO_2 by 51 percent, NO_x by 40 percent, and CO_2 by 26 percent in 2010.[52]

ELI's analysis projected that the retail price of electricity would rise by 0.6 cents, to 6.63 cents per kilowatthour (1997 dollars), leading to total economic costs, mostly lost consumer surplus, estimated at $25.9 billion (1997 dollars) in 2010.[53] Total electricity generation was projected to grow modestly over the 1998-2010 forecast period but was projected to fall slightly in the policy case from the "business as usual," or reference, case. Total nameplate coal-fired generating capacity was projected to decline by about 9 percent, to 293 gigawatts in 2010, indicating that decreased capacity utilization rates for coal plants would not necessarily render them uneconomical. Natural gas prices were projected to increase by 21 percent in the policy case, with prices in 2010 climbing from $3.30 per million Btu in the reference case to $4.00 per million Btu in the policy case.[54] The report underscores the finding that integrated approaches to emission reductions offer significant efficiencies.

Reference Case Comparisons

Reference case results for the four studies examined here show reasonably similar starting points (Table 22).[55] In both the EPA and EPRI studies, the reference cases were calibrated to earlier versions of EIA's *Annual Energy Outlook*. EPRI used the *Annual Energy Outlook 1999* reference case, and EPA used the *Annual Energy Outlook 1998*. Projections of coal-fired capacity in 2005 are nearly identical, ranging from a high of 319 gigawatts in ELI's reference case to 303 gigawatts in the EPRI and ELI Business As Usual cases. In EPRI's Business As Usual case, coal capacity is projected to increase slightly by 2010, but in EPA's 1999 reference case it declines slightly. Projections of coal-fired generation are fairly divergent, ranging from a low of 1,770 billion kilowatthours in 2005 in ELI's reference case to a high figure of 2,156 in EIA's reference case. ELI's reference case, however, projects the lowest

[46]The authors put the upper bound at 1.36 cents per kilowatthour and the lower bound at 0.68 cents per kilowatthour (in 1998 dollars).

[47]Current coal capacity in East Central Area Reliability (ECAR) is about 84 gigawatts, suggesting a shift of about 56 gigawatts to gas.

[48]The high and low sensitivities incorporated the respective assumptions regarding high and low costs of conventional pollution abatement.

[49]In EIA's analysis, some reductions are projected to be achieved by building new renewable sources of generation, a factor not addressed in the Cleaner Power studies.

[50]Like NEMS, Haiku models some North American Electric Reliability Council regions as competitive; only in these regions are tradeable generation permits allowed.

[51]Small amounts of additional wind capacity were also projected.

[52]Reduced Hg levels were also projected in the ELI policy case, to 21 tons in 2010, or about a 75-percent reduction from the 1998 baseline of 80 tons.

[53]The analysis also identified $26.4 billion in public health benefits from reductions in SO_2 and NO_x as a result of lower particulate concentrations.

[54]In 1999, natural gas deliveries to electric utilities averaged 1,022 Btu per cubic foot; corresponding prices per thousand cubic feet would be about 2 percent lower.

[55]The study by Lee and Verma was regional in scope, preventing national comparisons.

Table 22. Key Reference Case Projections for Electricity Generation in Four Multi-Emission Studies, 2005, 2007, and 2010

Projection	EIA Reference Case			EPA 1999 Reference Case			EPRI E-EPIC Business As Usual Case			ELI Business As Usual Case	
	2005	2007	2010	2005	2007	2010	2005	2007	2010	2005	2010
Coal-Fired Capacity (Gigawatts)	302	312	317	305	304	301	303	303	305	319	321
Electricity Generation by Fuel (Billion Kilowatthours)											
Coal	2,156	2,235	2,284	2,084	2,091	2,114	2,052	2,065	2,096	1,770	1,805
Natural Gas	813	907	1,123	561	626	759	838	1,006	1,175	1,056	1,267
Nuclear	740	738	720	609	613	580	627	587	551	670	683
Renewables[a]	97	108	125	61	61	61	61	62	66	35	39
Electricity Demand (Billion Kilowatthours)	3,762	3,919	4,146	3,612	3,690	3,809	3,578	3,702	3,859	3,863	4,121
Electricity Price (1999 Cents per Kilowatthour)	6.2	6.0	5.9	NA	NA	NA	6.3	6.1	6.0	6.5	6.1
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.49	2.60	2.68	2.05	2.05	2.05	2.41	2.52	2.61	NA	3.37
Coal Minemouth Price (1999 Dollars per Short Ton)	14.76	14.23	13.69	NA	NA	NA	15.39	15.01	14.47	NA	NA
Carbon Dioxide Emissions (Million Metric Tons Carbon Equivalent)	637	658	686	605	615	621	620	634	657	652	671
Sulfur Dioxide Emissions (Million Tons)	10.4	10.1	9.7	11.0	10.9	9.7	10.5	9.8	9.2	10.1	9.0
Nitrogen Oxide Emissions (Million Tons)	4.22	4.19	4.20	4.22	4.25	4.15	3.99	4.03	4.10	5.52	5.52

[a]Excludes hydroelectric generation.
NA = not available.
Sources: **EIA:** National Energy Modeling System, run MCBASE.D121300A. **EPA:** U.S. Environmental Protection Agency, *Analysis of Emissions Reduction Options for the Electric Power Industry* (Washington, DC, March 1999), run HGIPM9C. **EPRI:** Electric Power Research Institute, *Energy-Environment Policy Integration and Coordination Study: Executive Report* (Washington, DC, April 2000), run Business As Usual. **ELI:** Environmental Law Institute, *Cleaner Power: The Benefits and Costs of Moving from Coal to Natural Gas Power Generation* (Washington, DC, November 2000), run Business As Usual.

coal share of generation in 2005, about 46 percent of total generation. Coal's share of generation is projected to stay about the same in each of the four cases from 2005 through 2010.

Projections of generation from natural gas in 2005 vary significantly in the reference cases, ranging from 561 billion kilowatthours in EPA's reference case[56] to 1,056 billion kilowatthours in ELI's study. The share of generation from gas, however, is projected to increase in all of the studies by 2010. ELI's share of gas generation expands the least, as both EIA and EPRI projections of gas generation grow at a faster rate. Gas-fired generation in the ELI reference case is substantially higher than in the other studies, especially EPA's 1999 reference case, which ELI exceeds by 495 billion kilowatthours in 2005 and by 508 billion kilowatthours in 2010.

Projections of nuclear generation exhibit widely disparate baselines in 2005, with EIA projecting 740 billion kilowatthours, EPA 609 billion kilowatthours, EPRI projecting 627 billion kilowatthours, and ELI 670 billion kilowatthours. All the studies except ELI project declining generation from nuclear sources, a trend that is most pronounced in the EPRI study, at about 12 percent by 2010.

Generation from nonhydroelectric renewable sources shows the largest response in the EIA reference case, with a projected increase from 97 billion kilowatthours in 2005 to 125 billion kilowatthours in 2010. Renewable generation increases in both the EPRI and ELI reference cases, from 61 billion kilowatthours to 66 billion kilowatthours in the former and from 35 billion kilowatthours to 39 billion kilowatthours in the latter. EPA's reference case projects no increase in renewable generation over the forecast period.

Electricity demand rises in all four reference cases, led by a 10-percent increase in the EIA study, with both EPRI and ELI projecting about a 7-percent increase and EPA a 5-percent increase. The average projected electricity price falls by similar amounts in the three studies that report prices,[57] in part because coal prices are projected to decline over the 2005-2010 period. Gas prices are projected to rise and coal prices are projected to fall across

[56]Includes generation from dual-fired facilities not otherwise specified.
[57]EPA's 1999 analysis does not report end-use prices.

all the studies. CO_2 emissions are projected to increase in all the reference cases, with EIA projecting the largest increase over the 2005-2010 period at just over 7 percent.

Comparison of Integrated Cases

In the cases that assume integrated multi-emission reduction strategies, the electric power industry is projected to respond with similar changes in the four studies. All the integrated cases project reduced coal capacity, reduced generation from coal, and increased generation from natural gas (Table 23). In three of the studies, gas prices are projected to rise over the relevant forecast horizon, and coal prices are projected to fall. EPA's analysis does not model a fuel price response.

Differences in the assumed CO_2 emission targets account for some of the differences in the projected industry response. From a reference case projection of 686 million metric tons carbon equivalent, EIA's integrated 1990-7% 2005 case assumes a reduction to 443 million metric tons carbon equivalent by 2010. EPRI's Current Policy Direction case assumes CO_2 emissions of 399 million metric tons carbon equivalent by 2010. The CO_2 targets of 567 million metric tons carbon equivalent and 515 million metric tons carbon equivalent in EPA's 1999 analysis are significantly more lenient.[58] Both the EIA and EPRI studies include a carbon allowance fee, but their emission targets are different. EPA's 1999 analysis did not report a carbon allowance fee.

The integrated cases in the four studies indicate that when CO_2 emissions are significantly reduced, the need to address directly the remaining emissions, NO_x and SO_2, is mitigated. In EIA's study, NO_x reductions of 75 percent below 1997 levels are projected to be achieved with far fewer NO_x equipment retrofits (only 197 gigawatts, compared with 312 gigawatts in the NO_x 2005 case). SO_2 equipment retrofits are projected to be 10 gigawatts in 2010 in EIA's integrated 1990-7% 2005 case, compared with 98 gigawatts in the SO_2 2005 case. The integrated cases in EPA's 1999 analysis indicate a similar industry response. Projected NO_x retrofits fall in the integrated cases relative to those in the NO_x only cases. Similarly, EPA projects greatly reduced need for scrubbers in the integrated cases, falling by more than half from 93 gigawatts in the 55-percent SO_2 reduction case to 45 gigawatts in the integrated 50-percent SO_2 reduction and the 515 million metric ton CO_2 reduction case.

The EIA study projects the greatest reduction in coal-fired capacity, from the reference case projection of 317 gigawatts in 2010 to 260 gigawatts in the integrated 1990-7% 2005 case in 2010. The EPA study, which projects steady levels of coal capacity when SO_2 constraints alone are assumed, projects about an 8-percent reduction in coal capacity to 279 gigawatts in 2010 when CO_2 emissions are capped at 515 million metric tons carbon equivalent. The EPRI study projects that coal capacity would fall by about 35 gigawatts from the reference level in 2010 in the Current Policy Direction case.

Coal-fired electricity generation is projected to decline in the integrated cases in all the studies, but the reductions vary in both magnitude and timing. In the EPA study, which projects far more coal-fired generation in its most stringent case than do the other studies, coal-fired generation still is projected to decline by 461 billion kilowatthours by 2010, to 1,653 billion kilowatthours. The EIA study projects a decline of more than half, and EPRI projects a drop of about 59 percent by 2010 in the Current Policy Direction case, virtually all of which occurs between 2005 and 2010.[59] Natural gas generation is projected to address most of the shortfall in coal-fired generation in all four studies. Renewable generation is projected to increase in all the studies except EPA's, and nuclear generation is projected to increase above reference levels in the EIA and EPRI studies.

Electricity demand is projected to be reduced in three of the studies, by about 8 percent in EIA's most stringent case, by about 7 percent in EPRI's Current Policy Direction case, and by about 2 percent in the ELI study. EPA's study does not model an endogenous demand response. Projected electricity prices are much higher in both the EIA and EPRI analyses, and a more moderate price increase is projected in the ELI study. EIA projects an electricity price of 8.4 cents per kilowatthour in 2010 in the integrated 1990-7% 2005 case, an increase of about 42 percent from the reference case projection. EPRI's Current Policy Direction case projects an average electricity price of 8.4 cents per kilowatthour in 2010, about a 37-percent increase over the reference level. In contrast, ELI projects a smaller increase of about 11 percent, to 6.8 cents per kilowatthour, an increase that only partially reflects the full cost of the coal phaseout, due to assumed efficiency gains from industry restructuring. Electricity prices are not reported in the EPA study.

In summary, although the four studies discussed in this chapter examine the impacts of efforts to reduce power sector emissions, they assume different emission targets and use different analysis approaches. As a result, it is difficult to compare the specific results of the studies. The general results are similar, however. All the studies find that efforts to reduce power plant emissions, particularly CO_2, would be expected to lead to a shift from

[58] Although it is not an integrated emission reduction scenario, ELI's cap on coal-fired generation results in significant reductions in projected CO_2 emissions, from 671 million metric tons carbon equivalent to 499 in 2010.

[59] ELI imposed a 50-percent reduction on coal-fired generation as the constraint.

Table 23. Key Projections for Integrated Emission Reduction Cases in Four Multi-Emission Reduction Studies, 2005 and 2010

Projection	EIA			EPA		
	Reference	Integrated 1990-7% 2005	Integrated 1990-7% 2008	Reference	50% SO_2 and CO_2 567 MMT	50% SO_2 and CO_2 515 MMT[a]
2005 Projections						
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	637	473	536	605	602	593
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	113	71	NA	NA	NA
NO_x Retrofits (Gigawatts)	110	196	60	199	196	194
SO_2 Retrofits (Gigawatts)	11	10	12	4	44	38
Coal-Fired Capacity (Gigawatts)	302	299	300	304	303	301
Electricity Generation by Fuel (Billion Kilowatthours)						
Coal	2,156	1,347	1,695	2,084	2,051	2,038
Natural Gas	813	1,367	1,098	561	586	526
Nuclear	740	740	740	609	609	609
Renewables[b]	97	166	174	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.49	3.46	2.85	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	14.76	13.07	13.70	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	3,762	3,564	3,648	3,612	3,612	3,539
Electricity Price (1999 Cents per Kilowatthour)	6.2	8.1	7.2	NA	NA	NA
SO_2 Emissions (Million Tons)	10.4	4.9	8.2	11.0	7.0	7.3
NO_x Emissions (Million Tons)	4.22	1.46	2.74	4.22	4.19	4.17
2010 Projections						
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	686	443	430	621	567	515
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	134	126	NA	NA	NA
NO_x Retrofits (Gigawatts)	115	197	146	209	200	190
SO_2 Retrofits (Gigawatts)	0	10	12	6	63	45
Coal-Fired Capacity (Gigawatts)	317	260	265	303	294	279
Electricity Generation by Fuel (Billion Kilowatthours)						
Coal	2,284	1,135	1,067	2,114	1,812	1,653
Natural Gas	1,123	1,839	1,935	759	1,054	972
Nuclear	720	741	741	580	580	580
Renewables[b]	125	253	254	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.68	4.33	4.16	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	13.69	11.82	12.03	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	4,146	3,832	3,868	3,809	3,809	3,568
Electricity Price (1999 Cents per Kilowatthour)	5.9	8.4	8.2	NA	NA	NA
SO_2 Emissions (Million Tons)	9.7	3.9	4.0	9.7	4.6	4.5
NO_x Emissions (Million Tons)	4.20	1.30	1.32	4.15	3.52	3.15

[a]Includes high efficiency assumptions.
[b]Excludes hydroelectric generation.
NA = not available.
Note: See Table 22 for EPA and EPRI reference case results.

Case constraints: **EIA:** CO_2 reductions to 1990 levels met in either 2005 or 2008, with CO_2 7% below 1990 level by 2010, NO_x 75% below 1997, and SO2 75% below 1997. **EPA:** carbon emissions capped at 567 MMT by 2008, and SO_2 emissions capped at 50% of CAAA by 2010; and carbon emissions capped at 515 MMT in 2008, and SO_2 emissions capped at 50% of CAAA and electricity demand reduced gradually beginning in 2001. Retrofits include units with both NO_x and SO_2 reduction technology. **EPRI:** Current Policy Direction—50% SO_2 reduction by 2007, CO_2 capped at 9% above 1990 in 2005-2008, constant thereafter; Carbon Glide—SO_2 emissions capped at 8.95 million metric tons carbon equivalent, CO_2 restrictions imposed in 2005, gradually increasing to 2030, so that cumulative CO_2 emissions by 2050 equal those obtained in Current Policy Direction case. **ELI:** coal-fired generation reduced by 25% from baseline (1998) levels by 2005, and by 50% from baseline by 2010.

Sources: **EIA:** National Energy Modeling System, runs MCBASE.D121300A, FDP7B05.D121300B, and FDP7B08.D121500A. **EPA:** U.S. Environmental Protection Agency, *Analysis of Emissions Reduction Options for the Electric Power Industry* (Washington, DC, March 1999), runs HGIPM18B and HGIPM11C. **EPRI:** Electric Power Research Institute, *Energy-Environment Policy Integration and Coordination Study: Executive Report* (Washington, DC, April 2000), runs Current Policy Direction and Carbon Glidepath. **ELI:** Environmental Law Institute, *Cleaner Power: The Benefits and Costs of Moving from Coal to Natural Gas Power Generation* (Washington, DC, November 2000), runs “Business as Usual” and “Coal Reduction.”

Table 23. Key Projections for Integrated Emission Reduction Cases in Four Multi-Emission Reduction Studies, 2005 and 2010 (Continued)

Projection	EPRI			ELI	
	Business As Usual	Current Policy Direction	Carbon Glide	Business As Usual	50% Coal Reduction
2005 Projections					
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	620	588	581	652	558
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	12	25	NA	NA
NO_x Retrofits (Gigawatts)	179	133	149	NA	NA
SO_2 Retrofits (Gigawatts)	12	0	0	NA	NA
Coal-Fired Capacity (Gigawatts)	303	286	290	319	308
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,052	1,874	1,854	1,770	1,327
Natural Gas	838	985	971	1,056	1,288
Nuclear	627	661	661	670	673
Renewables[b]	61	64	63	35	63
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.41	2.51	2.48	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	15.39	15.12	15.24	NA	NA
Electricity Demand (Billion Kilowatthours)	3,578	3,577	3,541	3,863	3,690
Electricity Price (1999 Cents per Kilowatthour)	6.5	6.6	6.9	6.5	6.8
SO_2 Emissions (Million Tons)	10.5	10.4	10.2	10.1	7.7
NO_x Emissions (Million Tons)	3.99	3.92	3.85	5.52	4.43
2010 Projections					
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	657	399	482	671	499
Carbon Allowance Fee (1999 Dollars per Metric Ton Carbon Equivalent)	0	116	56	NA	NA
NO_x Retrofits (Gigawatts)	185	133	149	NA	NA
SO_2 Retrofits (Gigawatts)	18	0	0	NA	NA
Coal-Fired Capacity (Gigawatts)	305	269	276	321	293
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,096	854	1,251	1,805	889
Natural Gas	1,175	1,943	1,690	1,267	2,061
Nuclear	551	623	623	683	685
Renewables[b]	66	157	208	39	92
Natural Gas Wellhead Price (1999 Dollars per Million Btu)	2.61	3.30	2.93	3.37	4.09
Coal Minemouth Price (1999 Dollars per Ton)	14.47	16.13	15.43	NA	NA
Electricity Demand (Billion Kilowatthours)	3,859	3,587	3,732	4,121	4,051
Electricity Price (1999 Cents per Kilowatthour)	6.1	8.4	7.2	6.1	6.8
SO_2 Emissions (Million Tons)	9.2	4.5	4.4	9.0	4.4
NO_x Emissions (Million Tons)	9.23	2.26	2.86	5.52	3.30

coal-fired generation to natural-gas-fired generation. In addition, they find that efforts to reduce CO_2 emissions would have the largest impacts, reducing the need to invest in equipment to mitigate NO_x and SO_2 emissions and making it easier, or less costly, to meet SO_2 and NO_x constraints. Generally, the studies estimate that compliance costs would vary directly with the stringency of the emission targets. Finally, the studies are in agreement that meeting combined constraints would ultimately cost less than meeting a series of individual constraints.