5. Comparisons with Other Studies

Introduction

This chapter is divided into two sections. The first describes selected studies in which a renewable portfolio standard (RPS) has been modeled as a policy option to increase electricity generation from eligible renewable sources. The results of those studies are compared with those obtained in the RPS cases of the present study. The second section describes another multiple emission reduction analysis, which examined potential reductions of mercury (Hg) emissions in combination with reductions in emissions of sulfur dioxide (SO_2) and carbon dioxide (CO_2). Comparisons of studies targeting emissions of SO_2, nitrogen oxides (NO_x), and CO_2 (but not Hg), singly and in various combinations, were included in the earlier analysis by the Energy Information Administration (EIA).[47]

As there are many different types of RPS and various mechanisms for their implementation, there are many analyses of different RPS proposals. Many were done more than a few years ago, making valid comparisons difficult.[48] Others did not focus on the electricity generation sector.[49] Very few modeled a 20-percent RPS target, and none modeled an RPS and multiple emission reductions jointly.[50] Analytical modeling of potential reductions in Hg emissions is relatively new, and comparative analyses may number as few as one. In this chapter, the results of EIA's current analysis are compared with results from three other RPS analyses and one analysis of Hg emission reductions:

- An EIA analysis in the *Annual Energy Outlook 2000* (*AEO2000*) that included sensitivity cases modeling an RPS[51]
- An RPS analysis by the Union of Concerned Scientists (UCS), also published in 1999[52]
- An RPS analysis sponsored by the Tellus Institute (Tellus), published in 1997[53]
- An Hg emission reduction analysis by the U.S. Environmental Protection Agency (EPA), published in 1999.[54]

The EPA mercury study was part of a larger analysis of multiple emission reductions, in which various reductions in SO_2 and CO_2 emissions were modeled in combination with Hg emission reductions.[55] No RPS analysis was included in the study.

[47]Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR/OIAF/2000-05 (Washington, DC, December 2000), Chapter 6.

[48]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).

[49]S. Bernow et al., *America's Global Warming Solutions* (Washington, DC: World Wildlife Fund and Energy Foundation, August 1999). This study focused on CO_2 reductions. In an offline analysis, a Systems Benefits Charge of 2 mills per kilowatthour induced a 10-percent share of generation from new renewable sources. Those generators were then modeled as planned capacity, and a 10-percent RPS was achieved.

[50]Interlaboratory Working Group. 2000. *Scenarios for a Clean Energy Future*, ORNL/CON-476 and LBNL-44029 (Oak Ridge, TN: Oak Ridge National Laboratory, and Berkeley, CA: Lawrence Berkeley National Laboratory, November 2000). This study modeled an RPS through an extension of the 1.5 cents per kilowatthour production tax credit (PTC) for wind and dedicated biomass installed by 2004 and a 1.0 cent per kilowatthour PTC for biomass co-firing in 2000-2004. The study's Advanced Scenario included an RPS, represented as an additional 1.5 cents per kilowatthour PTC for 2005-2008, with carbon reduction scenarios. The analysis covered all end-use sectors.

[51]Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washington, DC, December 1999), p. 18.

[52]S. Clemmer, A. Nogee, and M. Brower, *A Powerful Opportunity: Making Renewable Electricity the Standard* (Cambridge, MA: Union of Concerned Scientists, January 1999). See also S. Clemmer, D. Donovan, and A. Nogee, *Clean Energy Blueprint: A Smarter National Energy Policy for Today and the Future*, Phase I (Cambridge, MA: Union of Concerned Scientists, June 2001), web site www.ucsusa.org. The *Clean Energy Blueprint* analysis focuses on policies designed to improve energy efficiency and to develop renewable resources, including a 20-percent RPS by 2020. Projected savings on consumers' energy bills begin to outstrip the costs of the program in 2010, and net benefits over the period 2002-2020 total $31 billion (1999 dollars). Phase II, forthcoming in summer 2001, will address emission reduction strategies and improvements in power plant efficiency.

[53]S. Bernow, W. Dougherty, and M. Duckworth, "Quantifying the Impacts of a National, Tradable Renewables Portfolio Standard," *The Electricity Journal* (May 1997).

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

[55]The EPA is currently working on a comprehensive update of this modeling effort.

Models produce different results for many reasons. The following are some of the most important:

Representation of the energy system. All the models used in the studies compared here include detailed representations of the electricity generation sector, but there are some differences in terms of interaction with other energy sectors. For example, EIA's National Energy Modeling System (NEMS) is a comprehensive model, integrating not only energy supply but also end-use demand and macroeconomic feedback. NEMS endogenously projects consumer demand for each fuel and the prices at which the fuels are expected to be supplied in order to meet demand. Changes in assumptions, such as the addition of pollution control equipment, alter electricity dispatch decisions, leading to a fuel price response. NEMS then recalculates projections of fuel prices and consumers' response to them, based on the projected changes in the electricity generation sector. In contrast, EPA's Integrated Planning Model (IPM) does not endogenously integrate fuel supply and demand. Thus, the EPA analysis does not include an endogenous fuel price response to altered demand.[56] Neither the UCS analysis nor the Tellus analysis, despite being based on NEMS, included an endogenous price response to changing fuel demands in the generation sector, because only the Electricity Market Module was run.

Assumptions regarding costs and performance of pollution control technologies. The EIA and EPA analyses used similar cost assumptions for various control technologies; however, because the Hg targets are so stringent, often requiring large investment in control equipment, even minor differences in cost can affect the choice of retrofit equipment. Because information about the technologies to reduce Hg emissions is incomplete, there are differences in assumptions concerning practicable retrofit options. EIA's analysis allowed for as many as 32 distinct plant retrofit configurations, and EPA's analysis modeled 16 retrofit combinations; but it is unclear how many practicable combinations there are. Further, new research has been conducted since the time of the EPA report, resulting in some revisions to cost and performance parameters for Hg control technology.

Assumptions regarding the extent of renewable resources and the penetration of renewable technologies. Models may reasonably differ over the shape of the supply functions at more ambitious RPS levels. For example, the UCS analysis was more optimistic than EIA's analysis with regard to the technological costs of wind turbines as supply resources are depleted. As a result, much more wind generation was projected in the UCS study. The optimal rate of biomass co-firing at utility coal units is debatable, ranging not only in magnitude (from 5 percent to 10 percent) but also in the pace of deployment. NEMS models grid-connected central-station and distributed generators in its Electricity Market Module as well as distributed generation in its Residential Demand and Commercial Buildings Modules.[57] Other studies project increased supply of solar technologies through a variety of off-grid applications.

Assumptions regarding the effects of new renewable resources on existing industry reliability standards. Because of the intermittent nature of both wind and solar resources, their contribution to regional reliability is assumed to be less than their total capability. Under the more ambitious RPS targets, the share of generation from intermittent sources can approach maximum industry standards, which vary at the regional level. Reliability standards, determined through loss-of-load probability calculations, enable regions to meet their generating reserve margins. NEMS assumes that the maximum contribution of renewable generators is capped at 15 percent,[58] whereas other models may allow greater shares from intermittent sources.

Differences in reference scenarios. Energy models are heavily dependent on assumptions of baseline values for critical variables, the most important of which are fuel prices, especially natural gas, and the rate of growth for electricity demand. The studies compared below were conducted at various times over a five year period from 1997 to 2001, and consequently the studies begin from different values. Wellhead natural gas prices in 1998 and 1999 were both lower in real terms than in 1997, but prices were sharply higher in 2000.[59] Consequently, EIA's study uses a much higher wellhead price for the near term in its reference case. Generally, electricity demand growth has accelerated over the last several years, and the studies project increasingly higher growth rates as the reference year of the study moves forward. The Tellus study, using the *AEO1996* (initial forecast year 1996), and the UCS study, using the *AEO1998* (initial forecast year 1998), both assume demand growth rates of 1.4 percent, as does the *AEO2000* sensitivity case (initial forecast year 2000); and

[56]The EPA analysis did provide for slight increases in price at higher consumption levels, but the model results never reached those levels.

[57]Energy Information Administration, *Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO66(2001) (Washington, DC, January 2001); Energy Information Administration, *Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO67(2001) (Washington, DC, January 2001); see also E. Boedecker, J. Cymbalsky, and S. Wade, "Modeling Distributed Electricity Generation in the NEMS Buildings Models," (Washington, DC, September 2000), http://www.eia.doe.gov/oiaf/analysispaper/electricity_generation.html.

[58]In the present EIA analysis, only one region (Rocky Mountain-AZ) is projected to reach the maximum.

[59]Energy Information Administration, *Annual Energy Review 2000*, DOE/EIA-0384(00) (Washington, DC, July 2001), Table 6.8.

the current EIA study used a growth rate of 1.8 percent (initial forecast year 2000). EPA's Hg analysis assumed a 1.6-percent growth rate from 1997 to 2000 and a 1.8-percent growth rate from 2001 to 2010.

On the other hand, the analyses compared here have a number of similarities. The three RPS studies were based on the NEMS Electricity Market Module, with customized modifications to its Electricity Capacity Planning Module. Although the RPS targets analyzed ranged from 4 percent to 20 percent, the technological menu available to each model was similar, regional resource attributes were roughly similar, and electricity prices in competitive regions were assumed to depend on the marginal cost of generation. For Hg emissions, EPA's IPM model relied on a representation of coal supply similar to the Coal Market Module of NEMS, and abatement strategies were assumed to rely on the same types of control technologies applied to similarly representative plant configurations. Baseline assumptions about the generation fuel mix and Hg emissions in the two studies are comparable.

RPS Analyses

EIA's *AEO2000* Analysis of a 7.5-Percent RPS

EIA analyzed a 7.5-percent RPS target as a sensitivity case in the *AEO2000*. With the RPS targets set at 2.4 percent for the years 2000-2004, then increasing linearly to 7.5 percent in 2010 (see Table 29), the case replicated the targets called for in the Comprehensive Electricity Competition Act (CECA). An interesting feature of the CECA RPS was a cap of 1.5 cents per kilowatthour on the price of renewable credits. For the *AEO2000* analysis, EIA modeled three sensitivity cases, one of which removed both the 1.5-cent cap and a sunset provision, which would have allowed the 7.5-percent RPS target to lapse after 2015 (the "no cap, no sunset" case). The effects of the RPS were isolated by removing the renewable credit cap and using reference case assumptions about the regulation of wholesale electricity markets, rather than competitive assumptions.

In the no cap, no sunset case, EIA found that about 30 gigawatts of wind, 9 gigawatts of dedicated biomass, and 5 gigawatts of geothermal capacity were added to reference case projections by 2020 to meet the 7.5-percent RPS target. Electricity prices in 2020 were projected to be 0.3 cents higher than in the reference case. In two other RPS sensitivity cases, both of which included either the 1.5-cent cap on renewable credit prices or the sunset provision, it was projected that the 7.5-percent RPS target would not be achieved. A maximum 1.5-cent renewable credit was found to be largely insufficient to overcome the cost advantages enjoyed by fossil technologies and meet the relatively modest 7.5-percent target.

UCS Analysis of a Range of RPS Targets

In January 1999, UCS published a study analyzing several RPS proposals under consideration in Congress. The proposals ranged from modest RPS targets of 4 percent by 2010 (Schaefer bill, H.R. 655) to 20 percent by 2020 specified in the most ambitious proposal (Jeffords bill, S. 687) and included the CECA proposal of 7.5 percent.[60] As such, the proposals represented increases in electricity generation from renewable sources ranging from 10 percent to about 500 percent above reference levels.

Like the EIA analysis, the UCS modeled a national RPS requirement with trading of credits. UCS employed a model called RenewMarket, patterned after the Electricity Capacity Planning (ECP) module in NEMS. Like the ECP, RenewMarket compared the long-term costs of various technologies and allocated sufficient capacity to meet regional electricity demand at the lowest cost. Unlike the ECP, RenewMarket incorporated different assumptions about several renewable technologies. The forecast horizon for the UCS analysis was 10 years longer than that of NEMS, extending to 2030.

UCS incorporated four changes to RenewMarket with regard to wind and geothermal energy. UCS included an industrial growth rate penalty in the form of a capital cost multiplier that was applied when the growth in installed domestic capacity exceeded 20 percent per year on average over the previous 3 years. UCS also imposed a capital cost penalty on wind as the penetration of wind increased in a given region. The cost approximated the value of adding a combustion turbine to provide firm power as the capacity credit for wind declined at higher penetrations. UCS allowed RenewMarket to develop lower class wind resources at lower cost where it was economically feasible. Finally, UCS increased the amount of geothermal capacity that RenewMarket would allow to be built in a given year, from 300 megawatts to 1,000 megawatts.

The UCS analysis also used different assumptions in regard to the learning curve that provides for a reduction in capital costs as a technology penetrates the market. UCS assumed that exogenous factors, such as research and development and international growth, would spur further capital cost reductions across technology types. The NEMS assumption is more restrictive, limiting the international learning effect to a maximum of one unit per technology per year, regardless of the amount of international builds. RenewMarket also reduced the price response to declining demand for

[60]In the UCS analysis, the RPS was 5.5 percent, reflecting the original RPS goal of the Clinton Administration.

natural gas, resulting in higher prices and fewer builds of new gas-fired generators than would be obtained in the ECP.[61]

The UCS study found that the average price of electricity under an RPS increased from reference levels. Under the Jeffords proposal, a 20-percent RPS, UCS found that average electricity prices fell by 13 percent between 1998 and 2020, down from the 18-percent decline projected under reference conditions.[62] UCS also found that natural gas prices increased by less under the Jeffords proposal than under the other RPS targets examined over the forecast period. Although the 20-percent RPS target produced the highest net costs,[63] reaching a peak in 2024, costs were projected to decline rapidly over the remainder of the forecast horizon to 2030.

Tellus Analysis of a 4-Percent RPS in 2010

Two years before the UCS study, the Tellus study used NEMS to analyze an RPS proposal contained in Rep. Schaefer's bill, H.R. 655. That bill called for eligible renewable generation to supply 2 percent of total electricity generation in 2000, 3 percent by 2005, and 4 percent by 2010, making it one of the more modest RPS proposals. Basing their analysis on EIA's 1996 *AEO* reference case, the authors used the standard method of inducing additional renewable generation by imposing a negative "shadow price" on the operating cost of eligible renewable generation. By decrementing operating costs in this way, the RPS target was eventually met, and the shadow price reflected the national credit trading price.

The results of the Tellus analysis were similar to those of other studies. The authors found that meeting a 4-percent RPS target by 2010 increased average electricity prices by 0.03 cents per kilowatthour over reference levels. The shadow price peaked in 2005 at about 1.25 cents per kilowatthour, falling to about 1.0 cent in 2010. Most of the new generation came from wind sources, with geothermal also increasing its share significantly. These renewable sources tended to displace natural gas generation, although small amounts of coal and oil were also removed. At the regional level, California-Southern Nevada and the Pacific Northwest each accounted for about one-fourth of the new renewable generation, with the Rocky Mountain area, Texas, New England, and the Mid-Atlantic also projected to have significant increases. These regions combine high avoided costs with favorable renewable resource opportunities in responding to the constraints of the modeled RPS.

Comparison of RPS Results

The RPS targets and implementation schedules modeled for the EIA, UCS, and Tellus studies are shown in Table 29. Table 30 shows detailed results, where available. The current EIA study models a 20-percent RPS by 2020, as did the UCS analysis of the Jeffords bill. The RPS target in EIA's *AEO2000* no cap, no sunset case was lower, 7.5 percent (by 2010), and the Tellus analysis assumed the 4-percent requirement (by 2010) proposed in the Schaefer bill. Also shown in Table 30 are the results for EIA's integrated RPS case with reductions for four targeted emissions. The Tellus study is not included in Table 30 because of a lack of comparable quantitative results.

Differences in baseline values, largely attributable to the timing of the studies, influenced the ease with which the RPS target could be met. EIA's reference case for the current study, based on the *AEO2001*, estimated that generation from eligible renewables was 80 billion kilowatthours, accounting for only 2.1 percent of total generation in 2000; the UCS study, based on *AEO1998*, projected a 2.9-percent share for renewables in 2000. The Tellus study, which did not include electricity generated by cogenerators for their own use, projected that renewables would account for 1.9 percent of total electricity generation in 2000. In addition, because the studies used different base years, there were significant differences in the initial (year 2000) prices of natural gas: UCS, $2.59 per million Btu to electricity generators; EIA (*AEO2000*), $2.20 per million Btu; and EIA (current study), $3.46 per million Btu at the wellhead (values converted to 1999 dollars).

Table 29. Assumptions for Renewable Portfolio Standards and Timing in Four Analyses

Study	RPS Target and Implementation Schedule
EIA, Current Study. .	5% by 2005, 10% by 2010, 20% by 2020
EIA, *AEO2000*	2.4% 2000-2004, increasing to 7.5% by 2010
UCS.	5% by 2005, 10% by 2010, 20% by 2020
Tellus	2% by 2000, 3% by 2005, and 4% by 2010

Sources: **EIA, Current Study:** National Energy Modeling System, run M2RPS20_x.D070601A. **EIA, *AEO2000*:** National Energy Modeling System, run RPS2KFUL.D100699B. **UCS:** S. Clemmer, A. Nogee, and M. Brower, *A Powerful Opportunity: Making Renewable Electricity the Standard* (Cambridge, MA: Union of Concerned Scientists, January 1999). **Tellus:** S. Bernow, W. Dougherty, and M. Duckworth, "Quantifying the Impacts of a National, Tradable Renewables Portfolio Standard," *The Electricity Journal* (May 1997).

[61]For example, in 2020 RenewMarket projects a price decline of $0.015 per million Btu for each quadrillion Btu reduction in cumulative consumption. Prior to 2005, changes in gas consumption are assumed to have no effect on price in the UCS analysis.

[62]The UCS analysis used the 1998 *AEO* reference case, which projected a decline of 1.1 cents per kilowatthour in average U.S. electricity prices between 1998 and 2020.

[63]Net cost was defined as increased expenditures on electricity minus savings from lower natural gas prices.

The different models projected similar responses to the RPS constraints. Generally, natural gas prices were projected to fall, CO_2 emissions were projected to be reduced in proportion to the RPS target, and NO_x and Hg emissions were projected to be reduced slightly. SO_2 emissions tended to remain fairly constant, with each study representing the CAAA90 SO_2 cap of 8.95 million tons.

The RPS increases the price of electricity on average, mostly because these generating sources are more expensive than coal- or natural-gas-fired generation, and all the studies report prices that rise in proportion to the target modeled. EIA reports an increase of about 4 percent in the RPS case in 2010, and UCS reports an increase of 2 percent. The larger price impact in EIA's RPS study arose from different assumptions about

Table 30. Comparison of Key RPS Results

Item	EIA, Current Study: Reference	EIA, Current Study: RPS 20%	EIA, Current Study: Integrated All CO_2 1990-7%	EIA, *AEO2000* RPS Case	UCS[a]
2005 Projections					
Coal-Fired Capacity (Gigawatts)	313	312	312	312	285
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,159	2,129	2,066	2,094	1,945
Natural Gas	820	759	803	665	799
Nuclear	740	740	740	674	605
Nonhydroelectric Renewables	105	199	198	185	193
Wind	16	27	27	32	20
Biomass (Including Co-Firing)	45	82	82	105	102
Geothermal	18	59	57	19	42
Municipal Solid Waste and Landfill Gas	25	30	30	29	28
All Solar Sources	1	1	1	1	1
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.96	2.91	2.80	2.30	2.86
Electricity Price (1999 Cents per Kilowatthour)	6.4	6.4	6.7	6.4	6.4
Electricity Demand (Billion Kilowatthours)	3,794	3,787	3,747	3,627	3,581
Renewable Credit Price (1999 Cents per Kilowatthour)	0	4.9	3.2	NA	0.5
SO_2 Emissions (Million Tons)	10.38	10.39	8.55	10.60	NA
NO_x Emissions (Million Tons)	4.30	4.25	3.03	5.43	NA
Hg Emissions (Tons)	45.2	45.0	40.7	NA	NA
Carbon Emissions (Million Metric Tons)	644	625	598	626	589
2010 Projections					
Coal-Fired Capacity (Gigawatts)	327	316	281	308	270
Electricity Generation by Fuel (Billion Kilowatthours)					
Coal	2,297	2,157	1,268	2,101	1,852
Natural Gas	1,085	919	1,512	890	1,028
Nuclear	725	725	741	627	561
Nonhydroelectric Renewables	136	426	440	301	396
Wind	18	96	93	80	94
Biomass (Including Co-Firing)	56	190	211	151	208
Geothermal	31	104	99	35	57
Municipal Solid Waste and Landfill Gas	28	35	36	34	35
All Solar Sources	2	2	2	2	3
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.87	2.65	3.13	2.43	3.09
Electricity Price (1999 Cents per Kilowatthour)	6.1	6.3	8.6	6.3	6.3
Electricity Demand (Billion Kilowatthours)	4,147	4,117	3,830	3,883	3,856
Renewable Credit Price (1999 Cents per Kilowatthour)	0	4.5	3.0	NA	1.6
SO_2 Emissions (Million Tons)	9.70	9.70	3.60	9.70	NA
NO_x Emissions (Million Tons)	4.34	4.23	1.41	5.56	NA
Hg Emissions (Tons)	45.6	44.1	5.0	NA	NA
Carbon Emissions (Million Metric Tons)	693	639	441	646	582

[a]UCS gas price is in dollars per thousand Btu to electricity generators, not national average wellhead price.
NA = not available.
Sources: **EIA, Current Study:** National Energy Modeling System, runs M2BASE.D060801A, M2RPS20_x.D070601A, and M2P7B08R_x. D070601A. **EIA, *AEO2000*:** National Energy Modeling System, run RPS2KFUL.D100699B. **UCS:** S. Clemmer, A. Nogee, and M. Brower, *A Powerful Opportunity: Making Renewable Electricity the Standard* (Cambridge, MA: Union of Concerned Scientists, January 1999).

technology costs and renewable resource availability. The Tellus study projected a negligible price increase over the reference level in 2010 for the 4-percent RPS target.

In each study, generation from nonhydroelectric renewables responded according to the RPS targets that were assumed. Both EIA's RPS 20% case and the UCS study projected well over 800 billion kilowatthours from eligible renewables by 2020. For 2010, EIA's RPS 20% case projected that generation from nonhydroelectric renewables would reach 426 billion kilowatthours in the RPS case, UCS projected 396 billion kilowatthours, and Tellus projected 144 billion kilowatthours. When joined with the emissions caps in EIA's integrated all CO_2 1990-7% case, generation from eligible renewables reaches 440 billion kilowatthours. All the studies showed significantly lower natural-gas-fired generation and smaller reductions in coal-fired generation. In EIA's RPS 20% case the decline was about 12 percent in 2010 for natural gas and about 8 percent in 2010 for coal. Similar declines were projected in the UCS and Tellus studies.[64] A slight decrease in demand was projected in both the RPS 20% case of the current EIA study and the EIA *AEO2000* analysis.

Of the eligible renewable sources, geothermal and biomass co-firing tend to be used first, and wind and dedicated biomass generation tend to be heavily exploited at higher RPS targets. In EIA's RPS 20% case, geothermal makes up 44 percent of the increase in 2005, but after all low-cost geothermal resources are taken, wind and biomass sources penetrate the market at a higher rate later in the forecast. Biomass co-firing is also important in the near term, making up 39 percent of the renewable increase in 2005 in EIA's RPS case. By 2010, the biomass contribution to generation is about twice as large as the wind contribution in both the EIA studies, and together they account for about 73 percent of the total increment in EIA's RPS case. Landfill methane is projected to fill a significant niche in all the analyses. Wind generation, however, clearly plays a critical role in all the studies. By 2010, wind accounts for 27 percent of the renewable increase in EIA's RPS 20% case and 24 percent of the increase in the UCS study. Despite different cost assumptions in the several models, all the studies indicate that even relatively modest renewable credit prices make wind technology competitive in favorable resource regions.

All the studies project that a national RPS would contribute to reductions of CO_2 emissions in the electricity generation sector. In the RPS 20% case, EIA projects a reduction of 54 million metric tons carbon equivalent (8 percent) from reference levels by 2010. The expected reduction is similar in the UCS analysis, 54 million metric tons carbon equivalent by 2010. EIA's AEO2000 analysis projected a reduction of 35 million metric tons carbon equivalent by 2010. The 4-percent RPS target modeled in the Tellus analysis yields a reduction of 9 million metric tons carbon equivalent, about 2 percent of reference case levels.

Renewable credit prices are comparable across the studies. EIA's 20-percent target (10 percent in 2010) results in a renewable credit price of 4.5 cents per kilowatthour in 2010 in the RPS case, after which the price declines. With the higher natural gas prices obtained in the integrated all CO_2 1990-7% case, the renewable credit price is reduced to 3.0 cents per kilowatthour in 2010. The UCS study projects a credit price of 1.6 cents per kilowatthour (1999 dollars) in 2010, but the longer forecast horizon (to 2030) results in a later peak of 2.7 cents per kilowatthour in 2024.[65] The 4-percent RPS target in the Tellus study yields a peak renewable credit price of 1.3 cents per kilowatthour (1999 dollars) in 2005, declining to 1.1 cents in 2010.

At the regional level, California-Southern Nevada and the Pacific Northwest are projected to become significant net suppliers of renewable credits to other regions in all the studies, and Texas and New England are also generally expected to be net suppliers in all the studies. With the higher RPS target in the UCS study and in the RPS 20% case of the current EIA study, MAPP (Upper Midwest) is projected to become the largest regional contributor to a national RPS target. At the lower target level in the Tellus study, wind resources in the MAPP region are not exploited, and the region is a net consumer of renewable credits.

[64]Bernow reports 48 billion kilowatthours of natural-gas-fired generation displaced and 4 billion kilowatthours of coal-fired generation displaced.

[65]The UCS methodology for calculating the credit price allowed renewable generators to see higher RPS targets in the future, so that while the target is increasing (as under the Jeffords proposal), more costs could potentially be recovered in the future, which tended to reduce the credit price in the near term. As the target is approached and / or met later in the forecast, the credit price and the shadow price tend to converge.

Mercury Emission Reduction Studies

EPA Analysis of Emissions Reduction Options for the Electric Power Industry

EPA's Clean Air Power Initiative (CAPI) produced a new series of modeling efforts in 1999.[66] The emissions analyzed were SO_2, NO_x, CO_2 and Hg. Slightly revising an earlier 1996 study,[67] NO_x emission reductions were not assumed beyond then-current statutory requirements, such as Phases I and II of the Title IV Acid Rain program or the NO_x SIP Call, under which 19 States and the District of Columbia must reduce NO_x emissions by 2004. Hypothetical emission caps were developed for each of the remaining emissions. The study allowed a variety of compliance options to meet the emission caps, including fuel switching, repowering, retrofitting or retiring units, and adjusting dispatch.

In modeling Hg emission reductions, EPA made assumptions about Hg concentrations in fuels and the control technologies plant operators might employ (Table 31).[68] Since the completion of EPA's report, further research has resulted in generally lower estimates of Hg concentrations by coal supply areas, accounting for some of the differences between the EPA and EIA assumptions shown in Table 31.[69] In its modeling, EIA also disaggregated by coal quality, allowing lower quality coals (gob and waste anthracite, not displayed in Table 31) to have much higher Hg concentrations than they would if combined in a weighted average with lower Hg coals. Still, EIA's estimates of Hg concentrations are lower in virtually all cases, reflecting the wide variability in Hg content among coal samples.[70] Concentrations of Hg in lignite from all regions are substantially less in EIA's estimate, and Hg concentrations in Powder River Basin subbituminous coal are also significantly different. Further differences are apparent in the important bituminous supply regions in Kentucky, West Virginia, and Pennsylvania.

There can be substantial variation in the Hg concentrations of coal from different coal seams within a State, and even within an individual coal mine. In some cases, the degree of variability reflects the uncertainty of using State-level values as a proxy for fuels consumed at

Table 31. Comparison of EPA and EIA Assumptions for Average Mercury Concentrations in Selected Coals
(Pounds per Trillion Btu)

State of Origin	Coal Rank	EPA Assumption	EIA Assumption
Alabama	B	11.91	8.16
Colorado	B	5.89	3.56
Illinois	B	7.18	5.84
Indiana	B	7.96	5.95
Kentucky	B	9.92	6.81
Louisiana	L	28.04	8.08
Maryland	B	26.58	15.55
Montana	B	8.38	NA
Montana	L	17.87	9.13
Montana	S	9.97	5.19
New Mexico	S	7.06	7.18
North Dakota	L	19.73	8.38
Ohio	B	14.94	15.72
Oklahoma	B	10.76	33.27
Pennsylvania	B	18.13	11.40
Texas	L	31.51	14.77
Utah	B	2.87	4.18
West Virginia	B	10.11	8.10
Wyoming	B	8.13	2.23
Wyoming	S	9.35	5.77

B = bituminous, L = lignite, S = subbituminous. NA = not available.

Sources: **EPA:** U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress*, Volumes I and II, EPA-453/R-98-004A and B (Washington, DC, February 1998). **EIA:** U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999).

[66]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 the development and analysis of alternative approaches to reducing three major emissions: SO_2, NO_x, and, potentially, Hg. The analysis used the Integrated Planning Model (IPM), a detailed model of the electric power industry in which plant operators react to alternative levels of pollution targets. 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 a fairly stringent absolute cap of 0.15 pounds per million Btu in 2005. At the same time, SO_2 was reduced in 2010 by lowering the Clean Air Act Amendments of 1990 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, 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 were published in 1996.

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

[68]EPA based the mercury concentrations on U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress*, Volumes I and II, EPA-453/R-98-004A and B (Washington, DC, February 1998).

[69]U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999).

[70]In 1999, EPA also estimated total Hg emissions at around 50 tons. Both EIA and EPA now estimate these emissions at around 43 tons.

coal-fired generating stations.[71] Further, EPA assumed a 21-percent reduction in Hg concentration from coal cleaning for bituminous coals shipped from 14 States, an adjustment not reflected in Table 31. The Hg concentrations used for EIA's analysis represented measurements taken at electric power plants, after preparation.[72] EPA and EIA used similar estimates for the negligible Hg concentrations in both oil and natural gas.

Another key difference between the EIA and EPA studies lies in the emissions modification factors (EMFs) corresponding to specific plant configurations (Table 32). After the Hg content of the fuel is estimated, Hg reductions in both models are calculated by applying assumed levels of reductions for specific items of control equipment. Plants may be configured with one or more control technologies, each assumed to reduce Hg in the flue gas by a certain percentage. The EMFs are nearly identical for particulate removal equipment. With regard to scrubbers, EPA modeled a generic scrubber with an EMF of 66 percent, whereas EIA used technology-specific EMFs for scrubbers ranging from 34 percent to 81 percent.[73] EPA and EIA also differed on the removal rate for fabric filters (also called baghouses), with EPA assuming an EMF of 56 percent and EIA 31 percent. EPA also assumed a variety of EMFs based on the boiler type present at the generating station, ranging from 41 percent to 100 percent. EIA, however, used a generic EMF of 93 percent, representing reductions in the combustion process from either the boiler-type or any NO_x controls.

Like the present EIA analysis, the EPA analysis concluded that the only viable control technology for directly reducing Hg emissions alone was activated carbon injection (ACI).[74] However, combining ACI technology with equipment designed to mitigate other emissions further reduces Hg, so that, effectively, plant operators have several compliance alternatives. EPA began with a simplified plant configuration menu of eight existing configurations,[75] each of which could fire either bituminous or subbituminous coal (16 model plant types), and then allowed the plants to deploy ACI in combination with spray coolers and / or fabric filters. Implied reduction rates for these mitigation options ranged from 65 percent Hg removal (cold side electrostatic precipitator using subbituminous coal with spray cooler and ACI) to 90 percent Hg removal (several combinations that include wet scrubbers).[76] EPA further assumed that higher reduction targets would require disproportionately greater amounts of activated carbon, reaching a peak ratio of 15,000 grams carbon to each gram Hg for the configuration of electrostatic precipitator with bituminous coal.

EPA's estimates of the costs for these technologies are compared with EIA's estimates for similar plant configurations in Table 33. Both EIA and EPA report high capital costs associated with the installation of fabric filters, and EIA's estimates of capital costs associated with spray coolers and fabric filters are slightly higher than EPA's. These capital costs, however, are generally less significant than the variable costs associated with activated carbon, so that the most important difference in the cost parameters lies in the assumptions regarding the efficiency of each model configuration. Whereas EPA fixed the rate of Hg reduction, EIA assumed that the rate of reduction would vary with the amount of carbon injected into the flue gas stream. Because EPA fixed

Table 32. Comparison of EPA and EIA Assumptions for Emission Modification Factors by Type of Emission Control Equipment
(Percentage of Hg Emissions Removed)

Emission Control Device	EPA Assumption	EIA Assumption
Flue Gas Desulfurization Scrubbers .	66	NA
Wet Scrubber (Bituminous Coal) . . .	NA	34
Wet Scrubber (Other Coals)	NA	81
Dry Scrubber	NA	61
Fabric Filter	56	31
Cold Side Electrostatic Precipitator . .	68	69
Hot Side Electrostatic Precipitator . . .	100	100
Particulate Matter Scrubber	96	96

NA = not available.

Sources: **EPA:** U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress*, Volumes I and II, EPA-453/R-98-004A and B (Washington, DC, February 1998). **EIA:** U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999), and National Energy Technology Laboratory.

[71] T. D. Brown, D. N. Smith, R. A. Hargis, Jr., and W. J. O'Dowd, "Mercury Measurement and Its Control: What We Know, Have Learned, and Need To Further Investigate," *Journal of the Air & Waste Management Association* (June 1999).

[72] There is much uncertainty about Hg reductions from coal preparation. A recent estimate has put the Hg reduction at nearly 60 percent. Rae-Hoan Yoon, "Developing Advanced Separation Technologies for Producing Clean Coal," testimony before the Subcommittee on Energy and Air Quality, U.S. House of Representatives (March 14, 2001).

[73] EMF rates refer to the amount of Hg remaining in the effluent gas.

[74] While recognizing that coal cleaning procedures could have some promise for lowering Hg emissions, neither EPA nor EIA modeled this alternative, due to a lack of information on the incremental costs of preparation to remove Hg.

[75] Both EIA and EPA estimated that about two-thirds of coal-fired capacity would add cold side electrostatic precipitators.

[76] U.S. Environmental Protection Agency, Office of Air and Radiation, *Analysis of Emissions Reduction Options for the Electric Power Industry* (Washington, DC, March 1999), Appendix C.

the rate of reduction, the analysis also fixed the ratio of activated carbon to Hg, yielding a linear cost curve for variable carbon costs. The last two columns of Table 33 compare EIA's estimate of variable carbon cost *at the reduction rate specified by EPA*; some of the costs are significantly different. As both analyses acknowledge, however, the rate of carbon injection must increase rapidly as higher Hg removal rates are pursued. At a reduction rate of 90 percent, EIA's variable costs for carbon, increasing exponentially rather than linearly, far outstrip those assumed by EPA.[77]

EPA employed two alternative cases to analyze potential Hg reductions, the first based on Maximum Achievable Control Technology (MACT) and the second using a market-based national cap and trade approach. The MACT option would apply to generators larger than 25 megawatts and take effect in 2007. Assumed technology options are ACI with spray cooling and / or fabric filters in certain instances. The cap and trade approach assumed the level of Hg reduction achieved by the MACT from 2007 to 2025 as the cap, and coal-fired generators could trade any Hg allowances received in that year with other generators in the contiguous United States.[78] No banking was allowed. Each of these approaches was modeled with an Hg reduction only, and with two other multiple emission reduction cases: a 50-percent SO_2 reduction by 2010, and a 50-percent SO_2 reduction with an additional CO_2 reduction to 515 million metric tons carbon equivalent in 2008. Cost impacts to the electric power industry were mitigated under the cap and trade model, reducing total resource costs by 23 percent in the fully integrated cap and trade case as compared with the MACT cases. Because it most closely resembles the present EIA analysis, EPA's cap and trade approach is compared below.

The EPA reported that annual incremental costs to the industry under the most stringent integrated scenario would be $6.3 billion (1999 dollars) in 2010. The incremental costs for reducing Hg alone were reported as $2.3 billion under a MACT standard and $2.1 billion under a cap and trade regime. EPA also found that, generally, the cap and trade approach reduced total incremental costs to the power generation industry (as compared with the MACT approach), but the savings were modest because the assumed technology costs for Hg removal did not exhibit significant economies of scale.[79] The greatest cost saving occurred in the integrated carbon reduction case, in which the use of cap and trade instead of MACT was projected to achieve a 23-percent cost reduction. Reduced electricity demand in this case mitigated the impact of the 50-percent SO_2 cap in the fuel selection process, allowing generators to select coal with lower Hg content and possibly higher SO_2 content. Thus, SO_2 reductions in 2010 were greater under the MACT scenario than under the cap and trade scenario. Emissions of NO_x, CO_2, and Hg were similar under the two regimes.

Comparisons of Mercury Reduction Results

Seven alternative policy cases are offered for comparison. The first is a national cap and trade case, where EPA caps national Hg emissions at 35 percent of the baseline projection in 2010, or about 17 tons, and EIA's Hg sensitivity case caps Hg emissions at 60 percent below estimated 1997 levels, or about 20 tons. Two multiple

Table 33. Comparison of EPA and EIA Assumptions for Costs of Mercury Emission Control Equipment by Selected Plant Configurations and Percentage of Hg Emissions Removed

Existing Configuration and Coal Rank	Controls Added	Percent Hg Removed	Capital Costs (1999 Dollars per Kilowatt)		Total Operating and Maintenace Costs, Excluding Activated Carbon (1999 Mills per Kilowatthour)		Variable Costs for Activated Carbon (1999 Mills per Kilowatthour)	
			EPA	EIA	EPA	EIA	EPA	EIA
Cold Side ESP, SUB . . .	SC and ACI[a]	65	8.24	NA	0.30	NA	0.31	NA
Cold Side ESP, SUB . . .	SC, ACI, and FF	65	NA	45.23	NA	0.29	NA	0.07
Hot Side ESP, BIT	SC, ACI, and FF	85	45.57	53.37	0.91	0.81	0.41	0.71
Hot Side ESP, SUB	SC, ACI, and FF	85	44.92	45.23	0.86	0.75	0.24	0.11
DS and ESP, BIT	Simple injection system	85	1.62	3.24	0.14	0.15	0.41	3.54
DS and ESP, SUB	Simple injection system	85	0.97	2.42	0.09	0.14	0.24	0.69

[a]EIA did not model a plant configuration of spray cooler with simple injection.

ACI = activated carbon injection, BIT = bituminous, DS = dry scrubber, ESP = electrostatic precipitator, FF = fabric filter, SC = spray cooler, SUB = subbituminous. NA = not applicable.

Notes: EPA's rates of reduction are fixed; EIA's variable costs are reported at the fixed level specified.

Sources: **EPA:** U.S. Environmental Protection Agency, Office of Air and Radiation, *Analysis of Emissions Reductions Options for the Electric Power Industry* (Washington, DC, March 1999), web site www.epa.gov/capi/multipol/mercury.htm. **EIA:** Unpublished data from the National Energy Technology Laboratory (NETL).

[77]The EPA and EIA studies assume the same cost for activated carbon, $1.00 per kilogram (1997 dollars).

[78]Therefore, EPA did not model a "hard cap" in either scenario. Reductions are compared with projected baseline emissions absent any policy change.

[79]Costs are annual incremental costs directly attributable to Hg control through retrofits and, to a lesser extent, altered fuel consumption.

emission reduction cases are compared, one with carbon emissions capped and one without. The targets for NO_x, SO_2, and CO_2 in the EIA analysis are significantly more stringent than those modeled by EPA.[80] In its integrated carbon case, EPA also assumed higher demand efficiencies, reducing electricity demand.[81] Finally, two MACT scenarios are compared. EPA's MACT scenario resulted in Hg reductions of 65 percent from projected baseline levels, while EIA's MACT 90% case projected Hg emissions reductions of 85 percent from 1997 levels.

Total coal supply is reduced under all Hg reduction scenarios (Table 34). Both EIA and EPA forecast only a modest drop in total coal production under a moderate Hg cap. Both models forecast an accelerated decline in coal production as SO_2 reductions are introduced, and both project substantial declines when CO_2 emissions become the policy goal. EIA's projection for electricity generation is significantly higher than that reported by the EPA because of greater coal capacity in 2010—about 30 gigawatts—as well as higher capacity factors and higher electricity demand. Because of different assumptions regarding Hg concentrations in Eastern coal, EPA and EIA forecast slightly different dynamics between the three Appalachian supply regions. In the EPA analysis, the Northern Appalachia supply region retains its production share and even increases its share under multiple emission reduction cases. EIA, in contrast, forecasts reduced production of Northern Appalachian coal in every policy case except under the 90% MACT reduction scenario. Conversely, EIA projects a modest increase in coals produced in Central and Southern Appalachia when Hg is targeted with SO_2, but EPA forecasts a declining role for these coals under all reduction scenarios except the MACT. The Midwest supply region obtains a larger market share in both the EIA and EPA forecasts in all but one policy case (integrated NO_x, SO_2, CO_2 1990-7%, Hg), to the extent that Midwest production increases from baseline levels. Because coal production declines generally when Hg is targeted, the supply of Western coal declines in all cases, but its market share holds fairly steady, in the 50 percent range, across all the scenarios. Higher sulfur Eastern coals also become slightly more competitive as Hg control equipment is added, especially in the MACT cases.

Because of the introduction of Hg control equipment, coal-fired capacity stays about the same across all the Hg reduction cases (Table 35); however, coal capacity loses some of its share when CO_2 reductions are introduced (integrated NO_x, SO_2, CO_2 1990-7%, Hg). In the cap and trade Hg reduction cases, EIA's 60-percent sensitivity case prompts 72 gigawatts of Hg retrofits (fabric filters and spray coolers) by 2010. In contrast, EPA's 65-percent reduction brings on 271 gigawatts of Hg retrofits in the same year. This different response highlights the role of variable levels of activated carbon usage in EIA's NEMS model, as compared with the constant levels of carbon injection employed in EPA's IPM. EIA also achieves a much larger share of the Hg reduction by deploying scrubbers, retrofitting 43 gigawatts by 2010, while EPA retrofits only 8 gigawatts. Interestingly, both EIA and EPA report modest declines in NO_x retrofits when Hg is the sole emission targeted. When CO_2 is

Table 34. Comparison of EPA and EIA Projections for Coal Supply by Region and Mercury Emissions Reduction Scenario, 2010
(Million Short Tons)

Coal Supply Region	EIA				EPA				
	Reference	Hg 20-Ton (60% Hg Reduction by 2008)	Integrated NO_x, SO_2, CO_2 1990-7%, Hg (90% Hg Reduction by 2008)	Hg MACT 90%	Reference	65% Hg Reduction, Cap and Trade	65% Hg Cap and 50% SO_2 by 2010	65% Hg Cap, 50% SO_2, 515 Carbon with High Efficiency	65% MACT
Northern Appalachia . . .	165	158	82	170	109	105	130	113	111
Central and Southern Appalachia	255	264	163	248	213	203	156	143	216
Midwest	136	172	106	150	109	131	162	149	127
West.	694	621	317	669	540	504	470	357	499
Central West and Gulf[a] .	44	24	6	46	63	50	47	14	58
Total	**1,295**	**1,239**	**674**	**1,282**	**1,034**	**992**	**964**	**776**	**1,011**

[a]Central West and Gulf corresponds to the Western Interior and Gulf supply regions in EIA's NEMS Coal Market Module.

Sources: **EIA:** National Energy Modeling System runs M2BASE.D060801A, M2M6008.D060801A, M2P7B08.D060801A, and M2M9008M.D060801A. **EPA:** 1999 Integrated Planning Model runs HgIPM9c, Hgtrading1d, Hgtrading2d, Hgtrading3d, and HgMact1d.

[80]EIA's integrated case includes a 75-percent NO_x reduction below 1997 levels, whereas EPA assumes NO_x reductions only to levels stipulated by the NO_x SIP call. EIA's SO_2 target is 75 percent below 1997 levels, whereas EPA's target is 50 percent reduction, to 4.8 million tons. EIA's CO_2 target is 7 percent below 1990 levels (about 440 million metric tons carbon equivalent), whereas EPA's CO_2 target is 515 million metric tons carbon equivalent. EIA's caps are based on assumptions provided by the House Government Reform Committee, Subcommittee on National Economic Growth, Natural Resources and Regulatory Affairs in its request for this study. See Appendix for full text of letter.

[81]Demand was assumed to be reduced by 1.5 percent annually, reaching a total reduction of 15 percent in 2010.

included in the integrated cases, fewer retrofits of all types are projected by both NEMS and IPM; however, similar levels of scrubber retrofits are necessary in both models to achieve the SO_2 targets. When MACT is chosen as the control regime, both EIA and EPA project that retrofits with activated carbon systems on virtually all coal-fired generating capacity will reduce the amount of scrubber retrofits needed to achieve the Hg targets.

Retrofitted with appropriate control technology, coal-fired generation is able to retain most of its market share in both the EIA and the EPA forecasts, although significantly, EIA generally projects more coal-fired capacity, including some new builds, and more coal-fired generation, factors which increase both the difficulty and the costs of meeting the targets. When Hg emissions alone are constrained, generation from coal is reduced only

Table 35. Comparison of Key Mercury Emission Reduction Results

	EIA				EPA				
Item	Reference	Hg 20-Ton (60% Hg Reduction by 2008)	Integrated NO_X, SO_2, CO_2 1990-7%, Hg (90% Hg Reduction by 2008)	Hg MACT 90%	Reference	65% Hg Reduction, Cap and Trade	65% Hg Cap and 50% SO_2 by 2010	65% Hg Cap, 50% SO_2, 515 Carbon with High Efficiency	65% MACT
2007 Projections									
Coal-Fired Capacity (Gigawatts)	319	317	303	317	303	304	303	302	305
NO_x Retrofits (Gigawatts)	118	118	150	118	199	192	191	189	192
SO_2 Retrofits (Gigawatts)	7	10	10	8	4	8	79	51	5
Hg Retrofits (Gigawatts)	0	0	0	0	0	270	245	250	303
Electricity Generation by Fuel (Billion Kilowatthours)									
Coal	2,220	2,207	1,653	2,212	2,091	2,080	2,043	2,011	2,085
Natural Gas	916	927	1,211	921	626	637	673	565	631
Nuclear	738	738	742	738	613	613	613	613	613
Nonhydroelectric Renewables	119	119	228	120	61	61	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.88	2.88	2.98	2.88	NA	NA	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	14.74	14.86	14.03	14.74	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.2	6.3	7.7	6.2	NA	NA	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	3,936	3,935	3,765	3,936	3,690	3,690	3,690	3,550	3,690
SO_2 Emissions (Million Tons)	10.1	10.1	6.4	10.1	10.9	10.5	5.4	6.5	10.5
NO_x Emissions (Million Tons)	4.30	3.44	2.04	3.43	4.25	4.25	4.20	4.09	4.25
Hg Emissions (Tons)	45.3	45.1	31.1	45.2	52.0	18.0	16.0	16.3	18.0
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	662	661	516	662	615	613	609	587	614
CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)	0	0	82	0	NA	NA	NA	NA	NA
SO_2 Allowance Price (1999 Dollars per Ton)	182	180	179	185	NA	NA	NA	NA	NA
2010 Projections									
Coal-Fired Capacity (Gigawatts)	327	323	277	324	303	304	301	284	304
NO_x Retrofits (Gigawatts)	119	118	177	119	209	192	190	181	193
SO_2 Retrofits (Gigawatts)	7	43	21	27	6	8	87	50	8
Hg Retrofits (Gigawatts)	0	72	105	356	0	271	251	249	302
Electricity Generation by Fuel (Billion Kilowatthours)									
Coal	2,297	2,237	1,113	2,266	2,114	2,073	2,006	1,681	2,099
Natural Gas	1,085	1,133	1,889	1,115	759	799	866	949	774
Nuclear	725	725	741	725	580	580	580	580	580
Nonhydroelectric Renewables	136	133	236	131	61	61	61	61	61
Natural Gas Wellhead Price (1999 Dollars per Thousand Cubic Feet)	2.87	2.90	3.66	2.89	NA	NA	NA	NA	NA
Coal Minemouth Price (1999 Dollars per Ton)	14.08	15.09	14.38	14.25	NA	NA	NA	NA	NA
Electricity Price (1999 Cents per Kilowatthour)	6.1	6.2	8.4	6.2	NA	NA	NA	NA	NA
Electricity Demand (Billion Kilowatthours)	4,147	4,132	3,851	4,140	3,809	3,809	3,809	3,568	3,809
SO_2 Emissions (Million Tons)	9.7	9.7	3.2	9.7	9.7	9.8	4.8	4.8	9.7
NO_x Emissions (Million Tons)	4.34	3.42	1.26	3.44	4.15	4.07	3.94	3.21	4.12
Hg Emissions (Tons)	45.6	20.0	5.0	8.0	50.9	17.5	15.1	12.8	17.6
CO_2 Emissions (Million Metric Tons Carbon Equivalent)	693	684	434	690	621	612	603	518	617
CO_2 Allowance Price (1999 Dollars per Metric Ton Carbon Equivalent)	0	0	120	0	NA	NA	NA	NA	NA
SO_2 Allowance Price (1999 Dollars per Ton)	187	0	0	114	NA	NA	NA	NA	NA
Incremental Costs (Billion 1999 Dollars)	0.0	1.7	23.2	5.9	0.0	2.1	5.2	6.3	2.3

NA = not available.

Note: Because Hg retrofits can include both fabric filters and spray coolers, retrofitted capacity may exceed total coal-fired capacity.

Sources: **EIA:** National Energy Modeling System runs M2BASE.D060801A, M2M6008.D060801A, M2P7B08.D060801A, and M2M9008M.D060801A. **EPA:** 1999 Integrated Planning Model runs HgIPM9c, Hgtrading1d, Hgtrading2d, Hgtrading3d, and HgMact1d.

negligibly by 2010. Further, in both the EIA and EPA MACT cases, coal-fired generation remains very close to reference levels. When SO_2 emissions targets are introduced, the IPM forecasts another slight reduction by 2010; in EIA's integrated NO_x, SO_2, CO_2 1990-7%, Hg case, however, the additional 75-percent NO_x reduction target forces a larger decrease in coal-fired generation by 2010. Both models reduce coal-fired generation significantly under carbon reduction regimes, although some of the decline in EPA's scenario can be traced to reduced demand under the high efficiency assumptions. Generally, increased gas-fired generation replaces the coal generation; however, both nuclear (in the form of reduced retirements) and nonhydroelectric renewables also make a contribution in EIA's cases, and by 2010 electricity demand falls as more emissions are targeted and retail electricity prices rise.

The patterns of emission reductions are similar in the EIA and EPA studies. Carbon emissions fall slightly from reference levels in the non-carbon cases, reflecting the decrease in coal-fired generation under Hg control policies. Substantial reductions in carbon emissions, however, require an explicit cap. Hg emissions in EIA's cap and trade cases reflect the hard-target caps, while in EPA's cases, Hg emissions continue to fall from the 65-percent reduction level as other emissions are targeted and more control equipment is added. The pattern of reductions, however, reveals that both models suggest a similar conclusion: marginal Hg reductions over a range from 65 to 80 percent come somewhat easily, but raising the target to 90 percent (or 5 tons Hg annually) increases the difficulty, and associated costs, exponentially. Both models suggest that NO_x emissions fall only slightly in the absence of explicit NO_x reduction targets. SO_2 emissions vary directly with the amount of scrubber retrofits, but when carbon is targeted, the shift to gas-fired generation leads to SO_2 reductions with fewer retrofits.

Both studies indicate that costs to the industry, either annual incremental costs in the EPA study or total resource costs in the EIA study, are mitigated by a cap and trade approach, but the savings under the cap and trade approach are not as dramatic as for other emissions, such as SO_2. In both models, there is only one control option (ACI), and assumptions used in both models provide for high removal rates. EPA assumed limited economies of scale, and EIA assumed none for ACI equipment. Therefore, opportunities for the industry to maximize Hg reductions at larger plants while purchasing allowances for smaller plants are relatively few. In the EPA study, the integrated cap and trade scenario does provide some benefits not available under the MACT. With significant scrubber retrofits and reduced demand, about one-tenth of the generators were able to address Hg reductions by switching to coals higher in sulfur but lower in Hg content, thereby avoiding installation of MACT controls—an alternative generally not available at the higher target levels modeled by EIA. The projected costs of compliance in EIA's analysis are higher than those found by EPA, because EIA projects higher electricity demand, more use of coal-fired generation, and more use of natural gas, especially in the CO_2 cap cases. In EIA's Hg 20-ton case, resource costs are projected to be $1.7 billion higher than in the reference case, compared to a difference of $2.1 billion in EPA's Hg cap and trade case.

One of the biggest potential concerns under an Hg cap and trade system is uneven regional distribution of emissions.[82] Allaying these fears somewhat, both EIA and EPA found that the regulatory regime, either cap and trade or MACT, did not introduce any significant differential impacts in regional emissions of Hg. Because they have most of the baseload coal capacity, the Southeast (SERC) and the Midwest (ECAR) regions are the largest contributors to Hg emissions. Under both control regimes, these two regions reduce their Hg emissions from reference levels by large amounts in both absolute and percentage terms. Both EIA and EPA forecast significant emission reductions in percentage terms for Texas (ERCOT). Because California and Florida have very little coal capacity, both EIA and EPA forecast slight increases in shares of national Hg emissions for those areas. The Mid-American Interconnected Network (MAIN, consisting of Illinois and Wisconsin) and the Middle Atlantic (MAAC) region exhibit different responses in the two models. EIA forecasts a slight increase in the share of emissions from MAIN, whereas EPA projects a significant decline. For MAAC, EIA forecasts a slight decline by 2010 and EPA a slight increase. The differences are likely attributable to slight regional shifts in the level of Hg emissions targeted.

Conclusions

The studies reviewed here share a number of similar conclusions. Under an RPS, biomass and wind generators provide most of the required renewable generation. Geothermal sources make an important contribution in the near term. At lower RPS target levels, wind turbines may be developed without much effect on the marginal cost of electricity in several regions. Natural gas prices play a critical role in analyzing the cost of achieving the RPS: where natural gas prices are low, the cost of replacing natural-gas-fired generation with any of these renewable sources is relatively high.

[82]"Any regulatory scheme for mercury that incorporates trading or other approaches that involve economic incentives must be constructed in a way that assures that communities near the sources of emissions are adequately protected." U.S. Environmental Protection Agency, *Federal Register*, Vol. 65, No. 245 (December 20, 2000).

With regard to Hg reductions, both EIA and EPA find that costs accelerate as reduction targets become more stringent. Imposing Hg reductions only has little effect on reducing other emissions. Reducing CO_2 and Hg emissions jointly leads to slightly greater Hg reductions. Incremental costs, however, rise rapidly when CO_2 is targeted along with other emissions. Controlling Hg emissions through a MACT rather than a cap and trade program does not affect regional distributions of emissions. The MACT approach, however, produces a smaller reduction in Hg emissions than the cap and trade approach and probably increases SO_2 emissions.