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Analysis of Alternative Mercury Control Strategies

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Background

This analysis responds to a September 14, 2004, request from Chairmen James M. Inhofe and George V. Voinovich asking the Energy Information Administration (EIA) to analyze the impacts of different approaches for removing mercury from coal-fired power plants. The senators asked that EIA analyze the impact of alternative mercury control strategies, including the Environmental Protection Agency's (EPA) proposed cap and trade system (EPA-Cap), EPA's proposed mercury maximum achievable control technology (EPA-MACT), and a 90-percent mercury MACT approach. Chairmen Inhofe and Voinovich also requested that EIA assume that EPA's proposed Clean Air Interstate Rule (pCAIR) is in force and that only commercially demonstrated mercury removal technologies can be used.

Summary

EIA's analysis finds that the EPA-Cap or EPA-MACT mercury control strategies are not expected to lead to large changes in the fuels used to generate electricity or electricity prices to consumers. The EPA-Cap strategy appears to dominate the EPA-MACT strategy in the sense that the former reduces emissions to a greater extent with lower impacts on electricity prices and fuels markets than the latter. The 90-percent MACT strategy achieves lower mercury emissions than the other two alternatives, but has higher impacts on fuel use and electricity prices. Furthermore, the fuel market and electricity price impacts of a 90-percent MACT are highly sensitive to the commercial availability of mercury removal technologies capable of 90-percent mercury removal from all plant and coal types by 2008. These technologies are now in development, but vendors may not be able to offer unqualified performance guarantees by 2008. If these new technologies are not commercially available, the 90-percent MACT strategy could lead to a significant shift out of western coals to eastern coals and out of coal to natural gas and renewables. This would increase the near-term electricity price impacts of a 90-percent MACT strategy more than ten-fold compared to a case in which these technologies are commercially available in time.

Key Findings

- Mercury emissions in 2025, which are estimated to reach 44.1 tons in the pCAIR baseline used in this report, are projected to range from 40.2 tons to 8.9 tons across the mercury control cases analyzed. In the EPA-MACT and EPA-cap cases emissions in 2025 are projected to be 40.2 tons and 30.1 tons respectively. The 15-ton mercury emissions cap imposed under the provisions of the EPA-Cap case is not expected to be reached because the safety valve limit on the price of mercury allowances is expected to be triggered. Projected emissions in 2025 under the 90-percent MACT case range between 8.9 tons and 9.9 tons depending upon the availability of mercury removal technologies.

- Very little fuel switching is projected in response to the proposed EPA-Cap or EPA-MACT mercury control strategies.

- The impact of the 90-percent MACT strategy on coal usage patterns depends heavily on the performance and commercial availability of new mercury removal technologies. If these technologies are available and able to achieve 90-percent mercury removal on all plant and coal types, western coal production is projected to be 4 percent lower then in the pCAIR baseline case, while Interior and Appalachian coal production is 4 percent higher. Without these technologies, a 90-percent MACT is projected to reduce 2025 western coal production by 60 percent while increasing Interior and Appalachian coal production by 35 percent.

- The 90-percent MACT strategy could also lead to lower use of coal for electricity generation and increased use of natural gas and renewables. With commercialized mercury removal technologies capable of 90-percent mercury removal on all plant and coal types, a 90-percent MACT is projected to lead to little change in coal, natural gas and renewable generation. However, without these technologies, coal generation in 2025 is projected to be 11 percent lower, while natural gas generation is 10 percent higher and renewable generation is 3 percent higher.

- The near term impacts of a 2008 90-percent MACT requirement without commercialized mercury removal technologies capable of achieving 90-percent removal from all plant and coal types could be very large, because it would require a rapid transformation of coal usage patterns together with rapid development of new natural gas and renewable supplies.

- The national average electricity price impacts of controlling mercury are projected to be small under the proposed EPA-MACT and EPA-Cap systems, with prices generally less than 1 percent higher than in the pCAIR baseline scenario. Similar results are projected in all regions under these control strategies.

- Small national average electricity price increases are also projected under a 90-percent MACT requirement provided that commercialized mercury control technologies able to achieve 90-percent mercury removal on all plant and coal types. Without these technologies national average electricity prices are projected to be 22 percent higher in 2010 and 7 percent higher in 2025. Regions that rely heavily on western subbituminous coals are expected to be the most strongly impacted, with price increases approaching 2.5 cents per kilowatthour projected for some regions in 2010.

- The impacts on resource costs and safety valve payments, the total costs to the industry, generally increase with the level of mercury removal required. Discounted resource costs and safety valve payments are projected to be $2 billion and $8 billion under the EPA-Cap and EPA-MACT systems, respectively. Even though projected mercury emissions are higher, the resource cost impacts under EPA-MACT are higher than those under EPA-Cap.

- With commercialized mercury removal technologies capable of 90-percent mercury removal on all plant and coal types, the 90-percent MACT strategy is projected to increase resource costs by $22 billion. However, without these technologies, it is projected to increase resource costs by $358 billion. These higher costs reflect the impacts of shifting away from relatively inexpensive subbituminous and lignite coals to other more expensive fuels. However, caution should be used when interpreting this result, because predicting the market price responses to such rapid shifts in fuel use patterns is very uncertain.

- There are significant uncertainties associated with this analysis including: the extent of mercury co-benefits from installing sulfur dioxide scrubbers and nitrogen oxide selective catalytic reduction units, the performance of mercury control technologies such as activated carbon injection, and when mercury control technologies will be commercially available with performance guarantees.

- The timing of any mercury control strategy is particularly important. Numerous mercury control technologies are currently being designed, tested, and evaluated. However, it could be several years before these technologies are fully commercialized.

1. Background

On September 14, 2004, Chairmen James M. Inhofe and George V. Voinovich requested that the Energy Information Administration (EIA) undertake an analysis of alternative proposals for regulating mercury emissions from coal-fired power plants.[1] The proposals included the Environmental Protection Agency's (EPA) proposed cap and trade system, EPA's proposed alternate maximum achievable control technology (MACT) approach, and a plant-by-plant 90-percent control MACT approach.[2] The senators specified that the analysis should assume the nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emission caps in EPA's proposed Clean Air Interstate Rule (CAIR). For mercury control, the senators specified that EIA only assume the use of "commercially demonstrated technology or technology where the vendor provides financially backed guarantees indemnifying the purchaser for failure to control at expected levels." This service report responds to Senators Inhofe and Voinovich's request.[3]

EPA's Proposed Cap and Trade System

Under the EPA cap and trade program, nationwide mercury emissions from electric generators would be capped at a yet-unspecified level between 2010 and 2017 (Phase I) and at 15 tons beginning in 2018 (Phase II). At this time, the Phase I cap has not been defined, and EPA has requested comments from the public on an appropriate level for the Phase I cap.[4] States would be allocated specific amounts of mercury allowances, which would constitute an authorization to emit a unit of mercury. Individual states would have the authority to allocate the allowances to their electricity generating units. The cap and trade program applies to coal-fired electric generators with capacities higher than 25 megawatts. The program also applies to combined heat and power units that are larger than 25 megawatts and sell more than one-third of their potential output to the grid.

A safety valve provision has been proposed that sets a maximum cost for mercury emissions reduction. Under this mechanism, the price of mercury allowances is capped. If allowance prices exceed the safety valve price, sources can borrow allowances from the following year's allocation. EPA has proposed a safety valve price of $2,187.50 per ounce (or $35,000 per pound), which will be annually adjusted for inflation. If the safety valve option is utilized, mercury emissions will exceed the emission cap. Banking of allowances after the start of the mercury trading program would be allowed without any restrictions.

In addition to the overall emissions cap, new coal-fired generating units have to meet New Source Performance Standards (NSPS) for mercury. The NSPS applies to electric generators with capacities higher than 73 MW or with greater than 250 million Btu/hour of fossil fuel

[1] See Appendix A for a copy of the requesting letter.
[2] The request also asked for analysis of the approach recommended by environmental group stakeholders in the formal recommendations to the Clean Air Advisory Committee by its workgroup studying mercury issues. EIA could not pursue this part of the request because neither Congressional staff or Environmental Protection Agency staff were able to provide information on the specifics of this recommendation.
[3] See Appendix B for a copy of our interim response to this request.
[4] A 34-ton Phase I cap is assumed in this analysis.

derived heat input. The NSPS standards also applies to combined heat and power units that are larger than 25 MW and sell more than one-third of their potential output capacity to the grid. New units are defined as those constructed, modified, or reconstructed after January 30, 2004. New coal and oil-fired units are required to meet emissions limits as shown in Table 1. Compliance will be determined based on a rolling 12-month average calculation. Mercury emissions would be determined by continuously collecting mercury emissions data from each affected unit by installing and operating a continuous emissions monitor or an equivalent approach.

Table 1. Mercury Emissions Limits for New Coal-fired Units

Coal Type	**Mercury emission limit (pounds per million megawatt-hour [1])**
Bituminous	6.0
Subbituminous	20
Lignite	62
Waste coal	1.1
Integrated Gasification Combined Cycle (IGCC)	20

1. Based on gross energy output.
Source: Federal Register, Vol. 69, No. 20, 40 CFR Parts 60 and 63 (January 30, 2004).

EPA's Alternate Proposed Maximum Achievable Control Technology (MACT) Approach

EPA's proposed MACT rule would also apply to electricity generating units larger than 25 MW and combined heat and power units larger than 25 MW that sell more than one-third of their potential output to the grid. Owners and operators of existing units will have the option of complying with either input- or output-based limits. Owners and operators of new units will be subject to output-based limits only. The proposed limits for existing and new coal-fired units are shown in Table 2. A new unit is defined as one in which construction or reconstruction began after January 30, 2004. New units have to be in compliance upon startup or by the effective date of the final rule, whichever is later. Existing units have to be in compliance no later than 3 years after the effective date of the final rule or the date on which the final rule is published in the Federal Register. Assuming the final rule is published in early 2005, existing units will have to comply in 2008. The proposed rule would allow emissions averaging as a compliance option for existing coal-fired units located at a single contiguous plant.[5] The emissions averaging approach can be applied to new coal-fired units as long as they meet the new unit limits in Table 2.

Table 2. Mercury MACT Emission Limits for Coal-fired Generating Units

Coal type	**Existing unit limits (pounds per trillion Btu or 10^{-6} pounds per megawatt-hour)[1]**	**New units limits (Pounds per million megawatt-hour)[1]**
Bituminous[2]	2.0 or 21	6.0
Subbituminous	5.8 or 61	20
Lignite	9.2 or 98	62
Coal refuse	0.38 or 4.1	1.1
IGCC	19 or 200	20

1. Based on 12-month rolling average.
2. Anthracite units are included with bituminous.
Source: Federal Register, Vol. 69, No. 20, 40 CFR Parts 60 and 63 (January 30, 2004).

[5] This analysis does address the potential impact of allowing emissions averaging for contiguous generating units.

Plant-by-plant 90-Percent MACT approach

In this approach, it is assumed that all coal-fired power plants would be required to achieve 90-percent removal of the mercury in the coal they use beginning in 2008.

2. Analysis

The analysis in this report was prepared using the Energy Information Administration's (EIA) National Energy Modeling System (NEMS). The reference case for the analysis was based on EIA's *Annual Energy Outlook 2005 (AEO2005)*, which incorporates only final regulatory action under existing laws.[6] It should be noted that the projections in the cases in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The reference case projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of planned regulatory changes, when defined, are reflected. Consistent with standard EIA practice requiring policy neutrality in baseline projections, the reference case in the *AEO2005* did not include pending or proposed actions, such as the proposed Clean Air Interstate and Clean Air Mercury Rules. Neither of these regulations had been finalized prior to the preparation of the *AEO2005*. However, as requested by the Senators Voinovich and Inhofe, for this report, the reference case has been modified to incorporate the power plant NO_x and SO_2 emission caps in EPA's proposed CAIR regulations.

The EIA analysis of mercury control strategies contained in this report, like other EIA analyses, focuses on the impact of the provisions in the bill on energy choices made by consumers in all sectors and the implications of those decisions for the economy. This focus is consistent with EIA's statutory mission and expertise. The study does not quantify, or place any value on, possible health and environmental benefits of curtailing mercury emissions.

Analysis Cases

At this time, there is significant uncertainty about the degree to which mercury can be removed from some coals. Currently, there are two main approaches being considered for controlling power plant mercury emissions; 1) reducing mercury emissions using technologies primarily designed to remove SO_2, NO_x, and particulate emissions (often called co-benefit reductions), and 2) reducing mercury emissions using technologies specifically designed to reduce mercury. Table 3 below provides the mercury removal factors used in recent EIA and EPA modeling work for different power plant configurations and coals. As shown for EIA, the assumed percentage of mercury removed varies from as low as 0 percent for many plant configurations using lignite coal to as high as 95 percent for several plant configurations using bituminous coals. Both sets of factors in Table 3 show that no coal plants using subbituminous or lignite coals are assumed to be able to comply with a 90-percent removal requirement using SO_2, NO_x, or particulate control technologies (i.e., co-benefit reductions) alone.

[6] Energy Information Administration, *Annual Energy Outlook 2005*, DOE/EIA-0308(2005), (Washington, DC, February 2005).

In order to continue to meet electric generating requirements and comply with a 90-percent mercury removal requirement at coal plants without using technologies specifically designed to reduce mercury, companies with plants that currently burn subbituminous or lignite coals would have to switch them to bituminous coals and add any needed NO_x, or SO_2 controls to reduce mercury emissions by 90 percent. This would require major changes in coal supply patterns, because subbituminous and lignite coals together accounted for roughly 50 percent of U.S. coal production in 2003. Alternatively, the companies could reduce their use of coal and increase their use of natural gas and renewable fuels or turn to mercury-specific control technologies.

Table 3. Mercury Removal Factors

Configuration			2010 EIA Capacity (gigawatts)	EIA Percent Removal			EPA Percent Removal		
SO_2 Control	Particulate Control	NO_x Control		Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	---	11	89	73	0	89	73	0
Wet	BH	None	10	95	73	36	97	73	0
Wet	BH	SCR	0	90	73	36	90	85	44
Dry	BH	---	7	95	25	0	95	25	0
None	CSE	---	92	36	3	0	36	3	0
Wet	CSE	None	30	66	27	42	66	16	44
Wet	CSE	SCR	82	90	27	42	90	66	44
Dry	CSE	---	8	36	35	0	36	35	0
None	HSE/Oth	---	31	10	6	0	10	6	0
Wet	HSE/Oth	None	13	42	20	0	42	20	0
Wet	HSE/Oth	SCR	18	58	24	36	90	25	0
Dry	HSE/Oth	---	6	40	15	0	40	15	0

Notes: SO_2 Controls – Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH = fabric filter/baghouse, CSE = cold side electrostatic precipitator, HSE = hot side electro static precipitator, NO_x Controls, SCR = selective catalytic reduction, --- = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations.

Sources: EPA factors, **http://www.epa.gov/clearskies/technical.html**. EIA factors not from EPA: Lignite factors, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/ HSE/Oth /SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

While many approaches are being considered, the most common technology discussed to remove mercury from coal plants is activated carbon injection (ACI). ACI systems have been widely deployed in other industries, mainly in waste-to-energy plants (municipal solid waste (MSW) plants). In those applications, they have achieved mercury removal rates in excess of 90 percent. However, ACI systems are only now being widely tested on U.S. coal plants and these plants have several characteristics that will tend to make mercury removal more difficult. For example, coal plants are typically much bigger with more flue gas to treat. They also have much lower concentrations of mercury and chlorine in the untreated gas, and it is questionable whether similar removal levels will be achievable for all coals. Sulfur and trace elements in U.S. coals may also pose problems that will have to be resolved. For example, efforts to remove mercury could create corrosive conditions that would damage other parts of the plants. Programs in the Department of Energy's Office of Fossil Energy are actively exploring these issues.

Because of these issues, the performance of these systems on coal plants and the guarantees that vendors would be willing to provide today are very uncertain. Vendors may be very conservative regarding guarantees until they have experience, and some problems could arise that limit the performance of these systems on particular plants or coals. As a result, depending on the stringency and timing of the mercury removal requirement imposed, it might be hard or costly for some plants to get a vendor's guarantee assuring compliance.

It should be pointed out that the understanding of this technology is changing rapidly, and EIA normally assumes that this technology will be available in the mid-term as might be required to comply with the 2010 or 2018 mercury emission caps called for in the Clear Skies Act of 2003. Whether current ACI systems for coal plants would meet the analysis request requirement for a "commercially demonstrated technology" for deployment in the 2008 timeframe, particularly if 90-percent removal is required, is unclear.

Because of the uncertainty about the availability and performance of mercury removal technologies, this analysis includes five mercury control cases with two of the most stringent cases incorporating alternative mercury control technology assumptions. Table 4 describes the cases prepared. The first case, labeled pCAIR, incorporates the proposed SO_2 and NO_x emission caps of EPA's proposed Clean Air Interstate Rule, and serves as the baseline case for this analysis. The second case, labeled EPA-Cap incorporates EPA's proposed mercury cap and trade program, while the third case, labeled EPA-MACT, incorporates EPA's proposed mercury MACT program. The final three cases incorporate a 90-percent mercury MACT with alternative assumptions about the availability and performance of ACI systems. These alternative cases are included in the most stringent mercury control case to illustrate the sensitivity of the results to the availability and performance of mercury control systems. They are not meant to project the expected evolution of the technology and the case without any ACI systems through 2025 is clearly unrealistic.

Table 4. Cases Prepared

Case Mnemonic	Description
PCAIR	AEO2005 Reference case plus NO_x and SO_2 emission caps from the proposed Clear Air Interstate Rule (CAIR).
Mercury Control Cases	
EPA-Cap	pCAIR plus EPA's proposed 15-ton cap and trade program for mercury.
EPA-MACT	pCAIR plus EPA's proposed MACT standard for mercury taking affect in 2008.
MACT90	pCAIR plus a 90-percent MACT for mercury taking affect in 2008 with ACI available and able to achieve up to 90 percent removal for all coals.
MACT90SL80	pCAIR plus a 90-percent MACT for mercury taking affect in 2008, where it is assumed that the maximum achievable mercury removal for plants using subbituminous and lignite coals is 80 percent.
MACT90NoACI	pCAIR plus a 90-percent MACT for mercury taking affect in 2008, where it is assumed that ACI technology is not available through 2025.

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

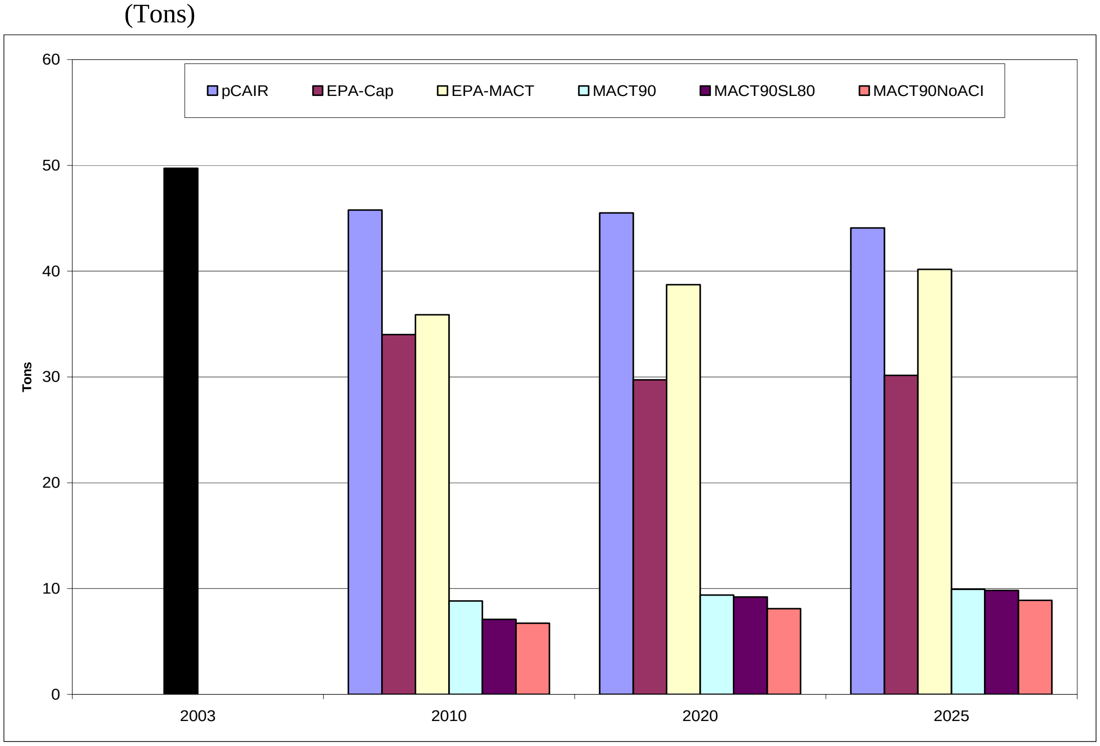
Mercury Emissions

Mercury emissions are projected to vary considerably across the cases, with 2025 emissions reaching 44.1 tons in the pCAIR case, 40.2 tons in the EPA-MACT case, and 30.2 tons in the EPA-Cap case (Figure 1). Mercury emissions in the EPA-MACT case are projected to fall only slightly below the projected emissions in the pCAIR case. This occurs because most plants using subbituminous coals will not have to take any action to meet the standard set for them. While the EPA-Cap case specifies a national emissions target of 15 tons for 2018 and beyond, it is not expected to be achieved. Mercury emissions are projected to exceed the 15-ton cap because power companies are expected to utilize the mercury safety valve provision. In this case, from 2018 on, it is projected that power companies will purchase mercury allowances at the safety valve price of $35,000 per pound, rather than installing mercury control equipment or switching coals. Purchasing allowances at the safety valve price is projected to be the cheapest compliance option.

In the MACT90, MACT90SL80, and MACT90NoACI cases, all coal-fired power plants would have to take action to remove 90 percent of the mercury in the coal they use, but there is no specific national emissions target. Under these assumptions, mercury emissions are projected to range from 8.9 to 9.9 tons in 2025. Mercury emissions in the no ACI case (8.9 tons in 2025) are lower than the other MACT90 cases (9.8 to 9.9 tons in 2025) because 46 gigawatts of coal plants opt to retire rather than comply with the 90-percent MACT without ACI.

Except for the no ACI case, the NO_x and SO_2 emissions paths are very similar in the mercury control cases. This occurs because these cases all assume the NO_x and SO_2 caps as imposed in pCAIR. NO_x emissions fall from 4.1 million tons in 2003 to 2.2 million tons in 2025, about half the level expected without pCAIR. SO_2 emissions fall from 10.6 million tons in 2003 to between 3.8 and 3.9 million tons in 2025, again, less than half the level expected without pCAIR. In the no ACI case, generators are expected to add additional SO_2 scrubbers and NO_x selective catalytic removal systems to reduce mercury resulting in SO_2 and NO_x emissions lower than the pCAIR targets, reaching 2.7 million tons and 1.6 million tons, respectively.

Figure 1. Mercury Emissions
(Tons)



Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

Mercury Control Compliance

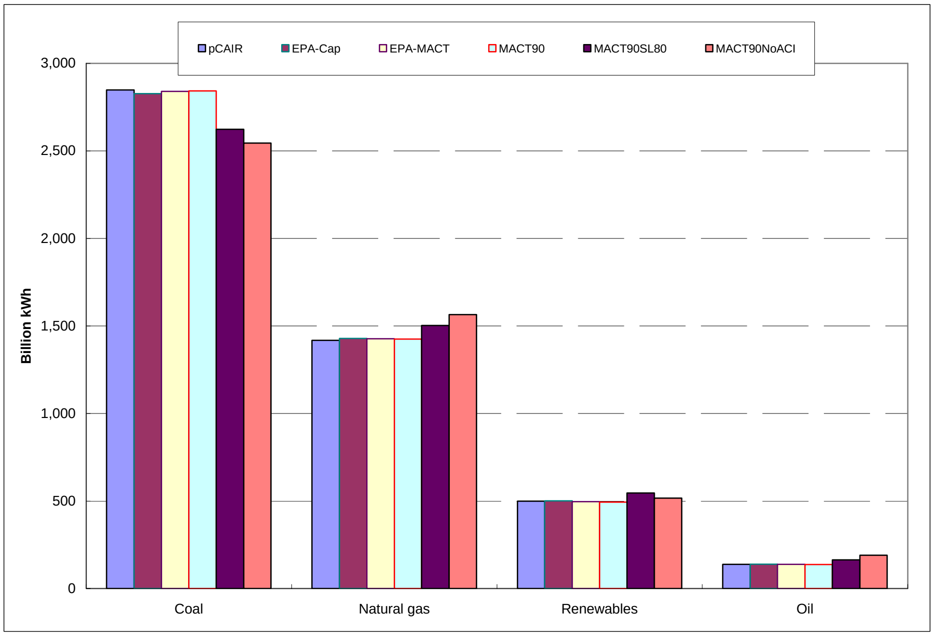
In each of the mercury control cases, mercury emissions are projected to be lowered through a combination of fuel switching between coals and from coal to natural gas and renewables, SO_2 scrubber retrofits, NO_x SCR retrofits, and ACI technology retrofits.

Fuel Switching

Almost no fuel switching is projected in the EPA-Cap and EPA-MACT mercury control cases. In these cases, there is expected to be a very small shift from coal to natural gas and renewables (Figure 2). However, the impact of a 90-percent MACT strategy on coal usage patterns depends heavily on the performance and commercial availability of new mercury removal technologies. If these technologies are available and able to achieve 90-percent mercury removal on all plant and coal types little fuel switching is projected under a 90-percent MACT strategy. However, if these technologies are not commercialized with this level of performance as in the two 90-Percent MACT cases with limited ACI performance or no ACI altogether, there is projected to be significant switching from coal to natural gas, renewables, and oil. There is also projected to be a dramatic switch in the types of coals used. In 2025, coal generation in these two cases is projected to be between 8 percent and 11 percent below the level projected in the pCAIR case. Conversely, 2025 natural gas generation in these two cases is projected to be between 6 percent and 10 percent higher, while 2025 renewable generation is between 3 percent and 9 percent higher. The shift to natural gas is even more pronounced just after 2008 when the MACT takes affect. For example, natural gas generation in 2010, in the MACT90NoACI case is projected to be 28 percent higher than in the pCAIR case. To meet the more rapid growth in demand for natural gas, companies will have to develop new supplies, particularly for liquefied natural gas (LNG), than otherwise expected. In the pCAIR case, LNG imports are projected to grow from 0.4 trillion cubic feet (tcf) per year in 2003 to 2.5 tcf per year in 2010. In the MACT90NoACI case, they are projected to reach 3.7 tcf in 2010 to meet the larger demand for natural gas. The rapid siting, permitting, and constructing of the terminals needed to meet this growth in LNG may be very difficult. Unfortunately it is unlikely that more than a minimal volume of additional LNG imports over baseline case levels would be able to enter the country by 2008. It is more likely that there would be sufficient time to add additional regasification facilities and that there would be more available liquefaction capacity around the world in the 2009 to 2010 time frame.

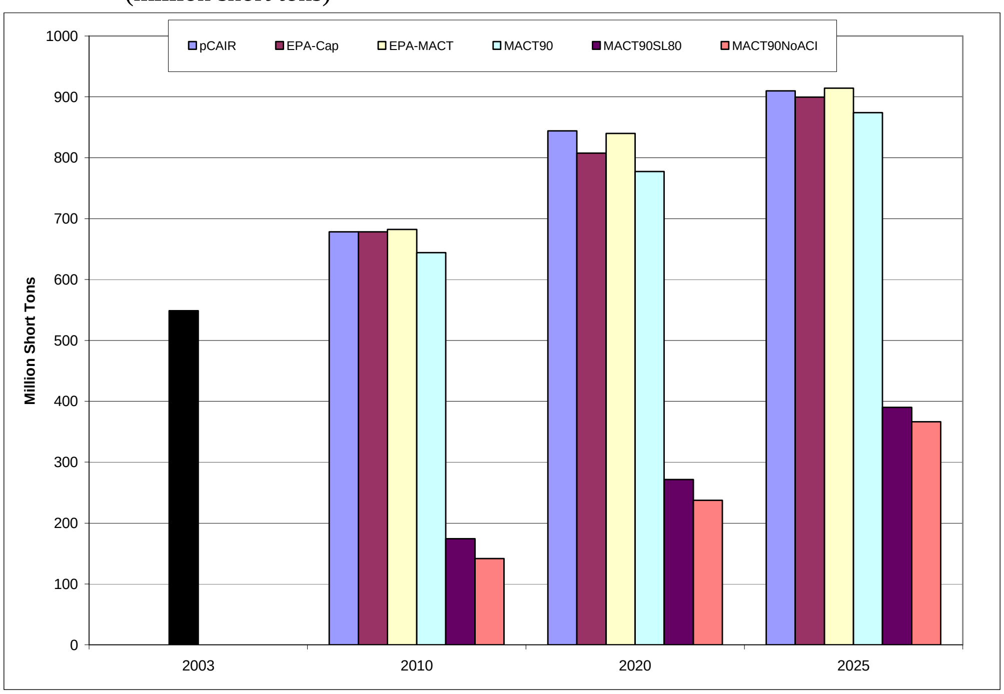
The shift in coal usage patterns in the two 90-percent MACT cases with limited ACI performance and no ACI is dramatic, with western coal use falling while eastern coal use increases (Figure 3). Western coal is primarily subbituminous coal from which mercury removal is more difficult than from bituminous coal. As Table 2 indicates, no plant configuration using subbituminous coal is assumed able to comply with a 90-percent MACT using SO_2, NO_x, or particulate control technologies alone. Mercury removal for a 90-percent MACT from subbituminous coals would require ACI technology. Plants currently using subbituminous coals would have to switch to bituminous coals or to natural gas or would have to retire in order to meet this requirement. In these two cases, western coal production decreases to between 366 and 390 million tons by 2025, compared to between 874 and 914 million tons in the other mercury control cases. There is actually a 4 million ton increase in western coal production in the EPA-MACT case, because the proposed standards for subbituminous coals can be readily met in most plants. In contrast to the west, Appalachian and Interior coal production in these cases increases

Figure 2. Generation by Fuel, 2025
(Billion Kilowatthours)



Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

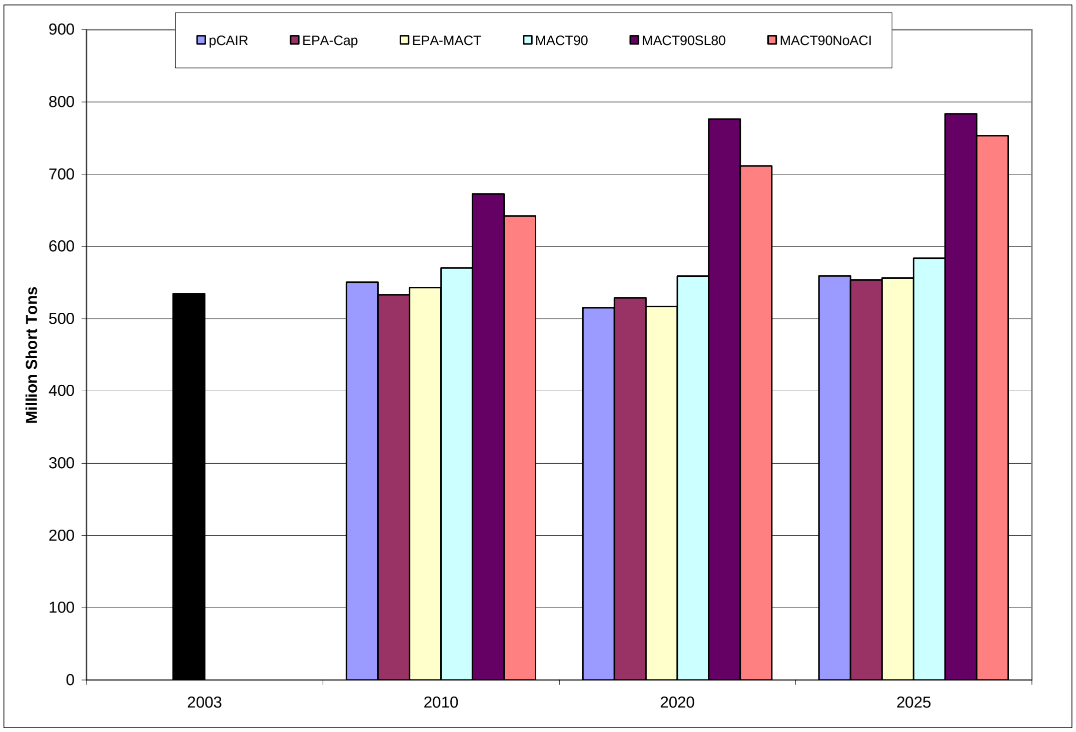
Figure 3. Western Coal Production
(million short tons)



Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

significantly (Figure 4). The increase in Appalachian and Interior coal is not as large as the reduction in western coal because increased natural gas and renewable generation displace some of the coal generation and each ton of western subbituminous coal contains approximately 70 percent as much energy as each ton of eastern bituminous coal. There is also a significant reduction in electricity demand in these cases due to higher electricity prices. The increase in eastern coal production called for in these cases may be very difficult to achieve. Coal production in the east has been declining since 1990 and it may be very difficult to reverse this trend.

Figure 4. Appalachian and Interior Coal Production
(million short tons)

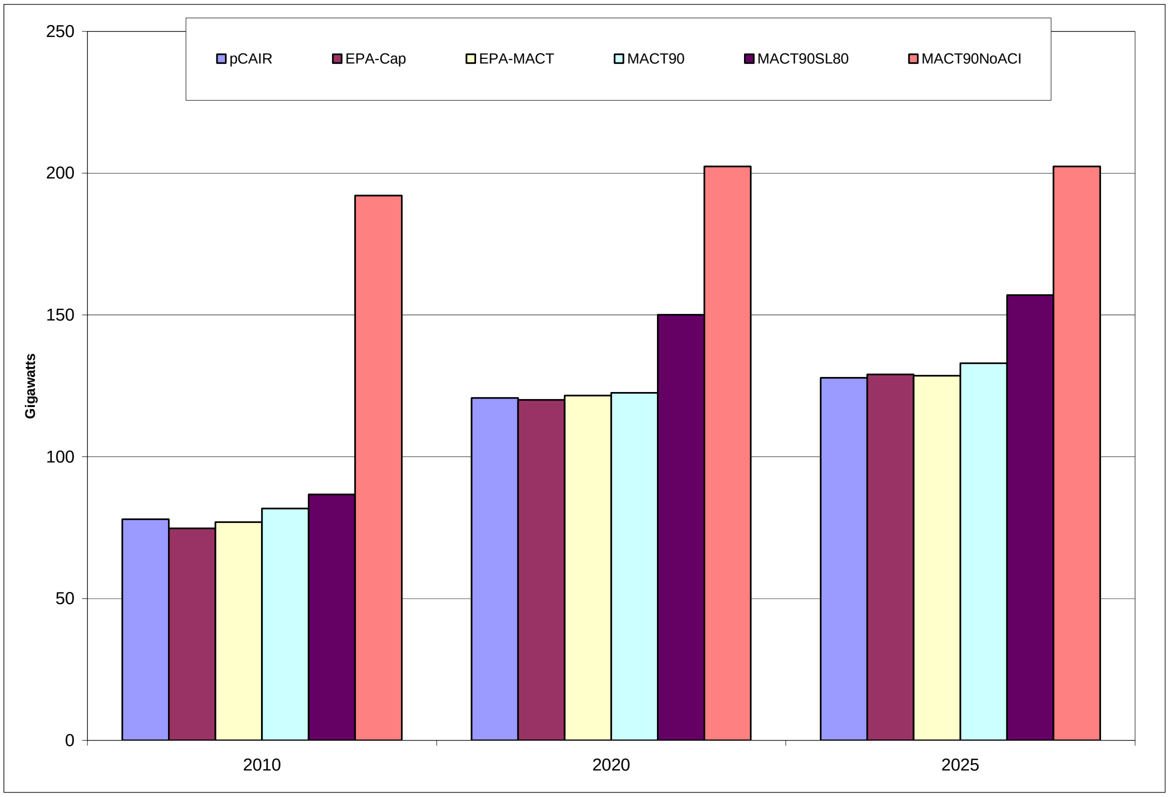


Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

SO_2 Scrubber Retrofits

A significant amount of SO_2 scrubbers are projected to be added in all cases in order to comply with the SO_2 emission caps established in pCAIR (Figure 5). For example, by 2025, 128 GW of coal-fired power plants are expected to be retrofitted with flue gas desulfurization scrubbers in pCAIR case. Even though SO_2 scrubbers also contribute to mercury removal, similar levels of SO_2 scrubber retrofits are expected in most of the mercury control cases. In the EPA-Cap, EPA-MACT, and MACT90 cases, between 1 and 5 additional gigawatts of capacity are projected to be retrofitted with SO_2 scrubbers. However, without commercialized mercury removal technologies capable of 90-percent removal, SO_2 scrubbers are projected to play a much bigger role in reducing mercury emissions under a 90-percent MACT. In the MACT90SL80 and MACT90NoACI cases, coal plant operators would have to limit their coal use to bituminous coal and add SO_2 scrubbers and NO_x SCRs in order to comply with the 90-percent mercury MACT. As a result, in the MACT90SL80 case, SO_2 scrubbers are expected to be retrofitted to an additional 29 gigawatts of capacity, while in the MACT90NoACI case, an additional 75 gigawatts of capacity are expected to add them.

Figure 5. Scrubber retrofits
(Gigawatts)



Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405a, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

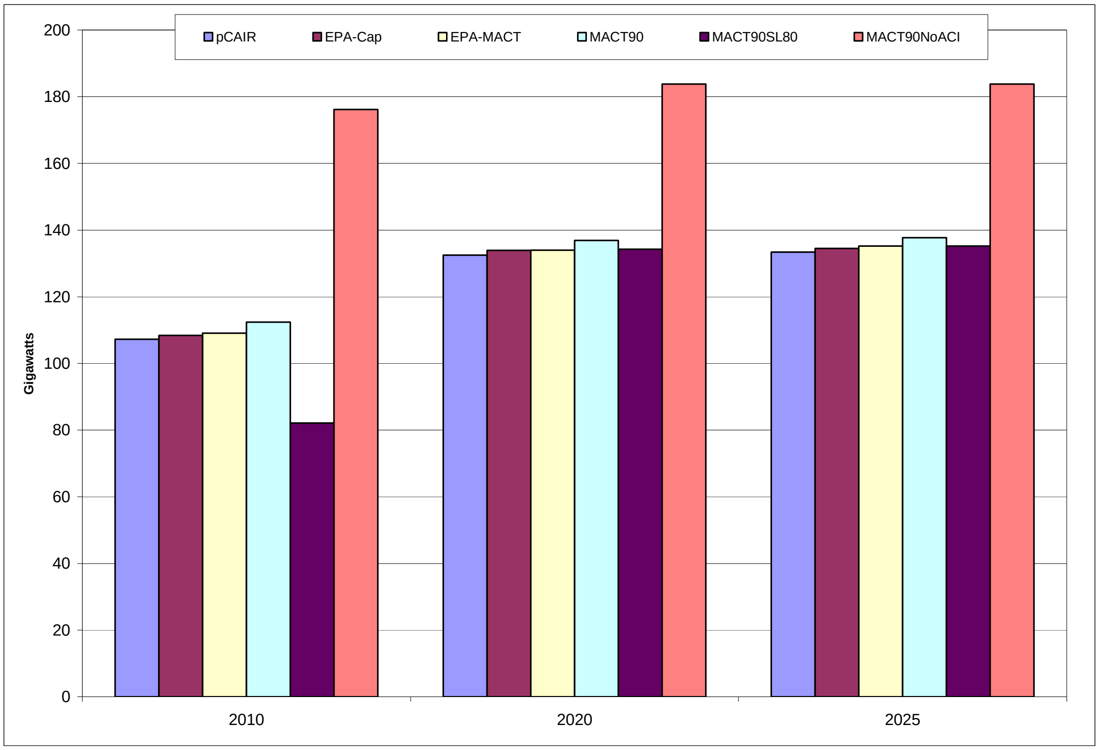
NO_x SCR Retrofits

The story for NO_x SCR retrofits is similar to that of SO_2 scrubber retrofits. All cases are projected to add a significant number of retrofits to meet the NOx emissions targets specified in pCAIR (Figure 6). Approximately 133 gigawatts of capacity are expected to add SCRs in the pCAIR case. In most of the mercury control cases, only a small amount of additional capacity is projected to add them. For example, in the EPA-Cap, EPA-MACT, MACT90, and MACT90SL80 cases, SCR retrofits grow to between 135 and 138 gigawatts of capacity. Only in the case with a 90-percent mercury MACT and no ACI technology available are significantly more SCRs expected. In the MACT90NoACI case, SCR retrofits are projected to be added to 184 gigawatts of capacity.

Activated Carbon Injection Retrofits

ACI technologies are projected to play a role in most of the mercury control cases. In the EPA-Cap case, ACI is projected to be used in conjunction with existing particulate control devices to reduce mercury. In other words, activated carbon will be injected in front of a plant's existing particulate control system to enhance its mercury removal. However, no relatively expensive supplemental fabric filters (often referred to as COHPAC systems – compact hybrid particulate collector) are projected to be added. The cap and trade system in the EPA-Cap case provides power plant operators the flexibility to reduce emissions at those facilities where it can be accomplished most economically. The need for supplemental fabric filters with activated carbon

Figure 6. SCR Retrofits
(Gigawatts)



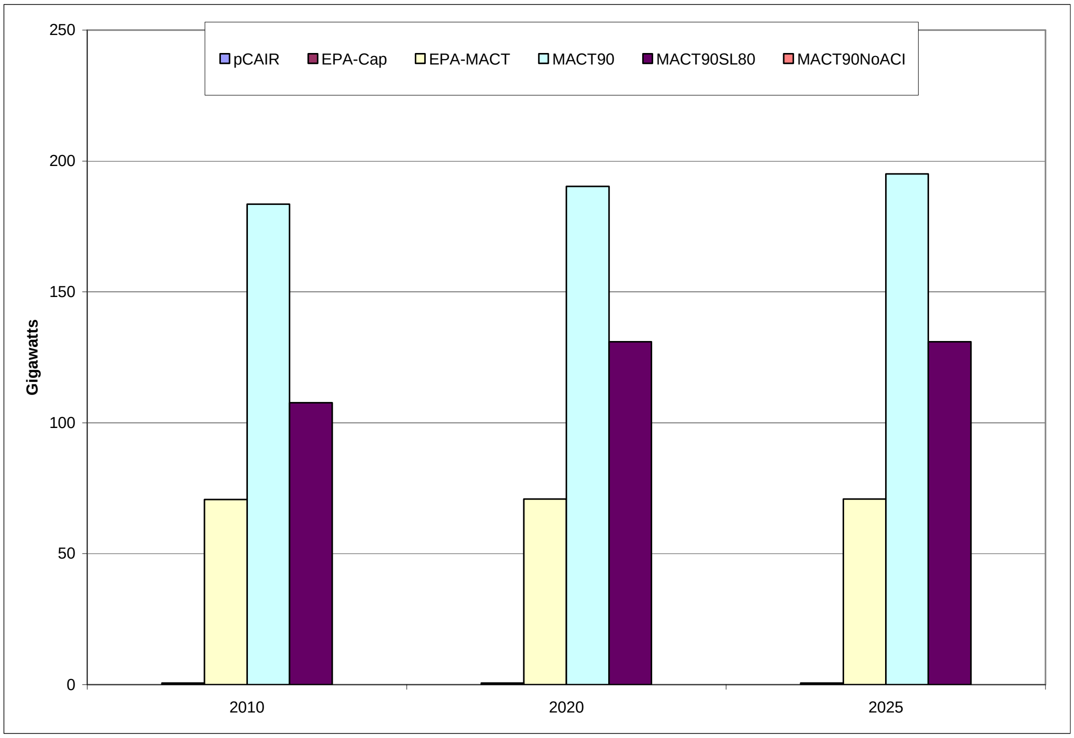
Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405a, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

injection is projected to be significant in the EPA-MACT, MACT90, and MACT90SL80 cases. In the EPA MACT case, approximately 71 gigawatts of capacity are projected to use these systems (Figure 7). In the MACT90SL80 and MACT90 cases, 131 and 195 gigawatts of capacity, respectively, is projected to add these systems. These systems are relied on more heavily in the MACT90 case, because they are assumed to be able to achieve 90-percent mercury removal on all plants and coals.

Fuel Prices

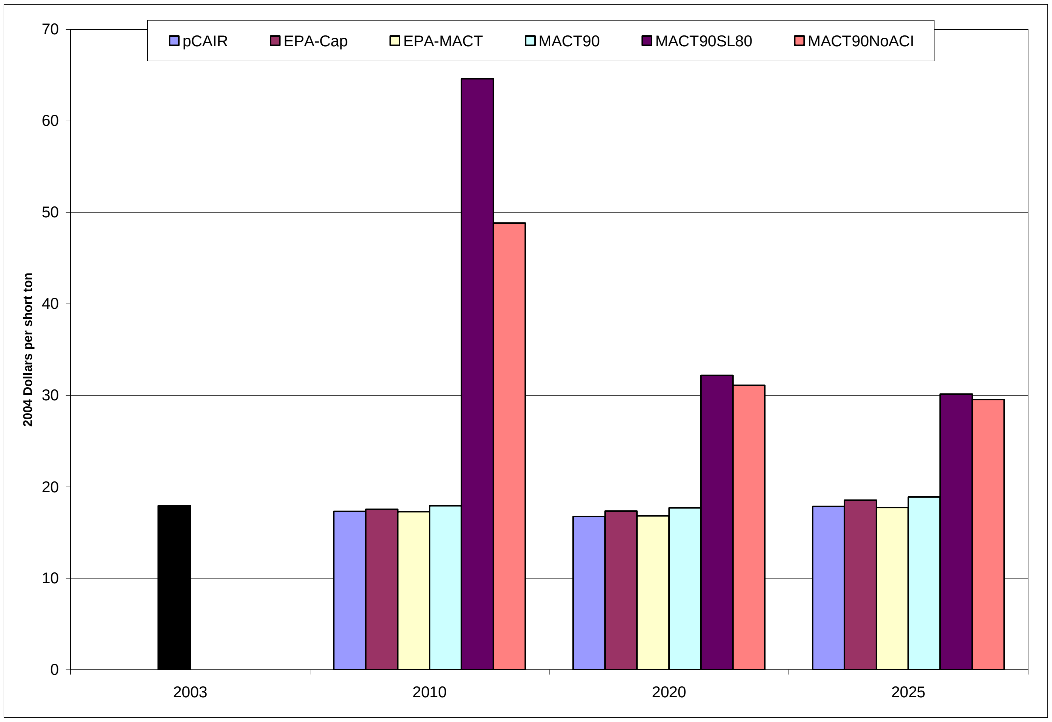
Because fuel switching is projected to play a small role in most of the mercury control cases, coal and natural gas prices are not expected to change significantly (Figures 8 and 9). However, in 90-percent MACT cases without commercialized mercury removal technologies capable of 90-percent removal on all plant and coal types, fuel price changes are projected to be larger. In fact, in the two cases with limited ACI performance or no ACI altogether, the projected impacts on coal and natural gas prices are significant, especially in the near term. With limited ACI performance or without ACI, complying with a 90-percent MACT could be extremely difficult and lead to significant fuel price impacts when the program first takes effect. In 2010, average coal minemouth prices, measured in dollars per ton, are projected to be between about 3 and 4 times the level projected in the pCAIR case. However, as will be mentioned several times,

Figure 7. Supplemental Fabric Filter with ACI
(gigawatts)



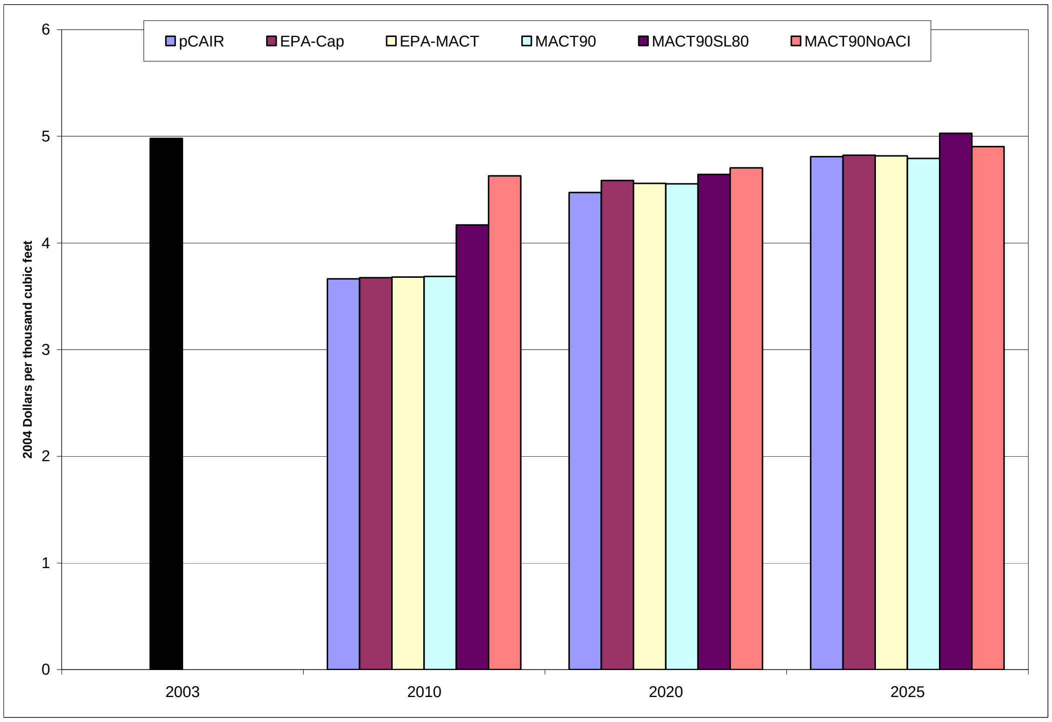
Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

Figure 8. Coal Minemouth Prices
(2003 dollars per short ton)



Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

Figure 9. Natural Gas Wellhead Prices
(2003 dollars per thousand cubic feet)



Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

caution should be used when viewing the cost and price results in these cases, because predicting the market responses to the fuel consumption shifts expected in these two cases are very difficult. By 2025, coal minemouth prices in these two cases are projected to be between 65 percent and 69 percent above the pCAIR case level. It should be noted that part of this increase in coal prices is due to a shift in the rank of coals consumed rather than an increase in delivered coal prices.

The minemouth price per ton of bituminous coals is generally higher because they have more energy per ton than subbituminous coals. Delivered coal prices per Btu to the power sector in 2025 are only projected to be between 30 and 36 percent higher than in the pCAIR case.

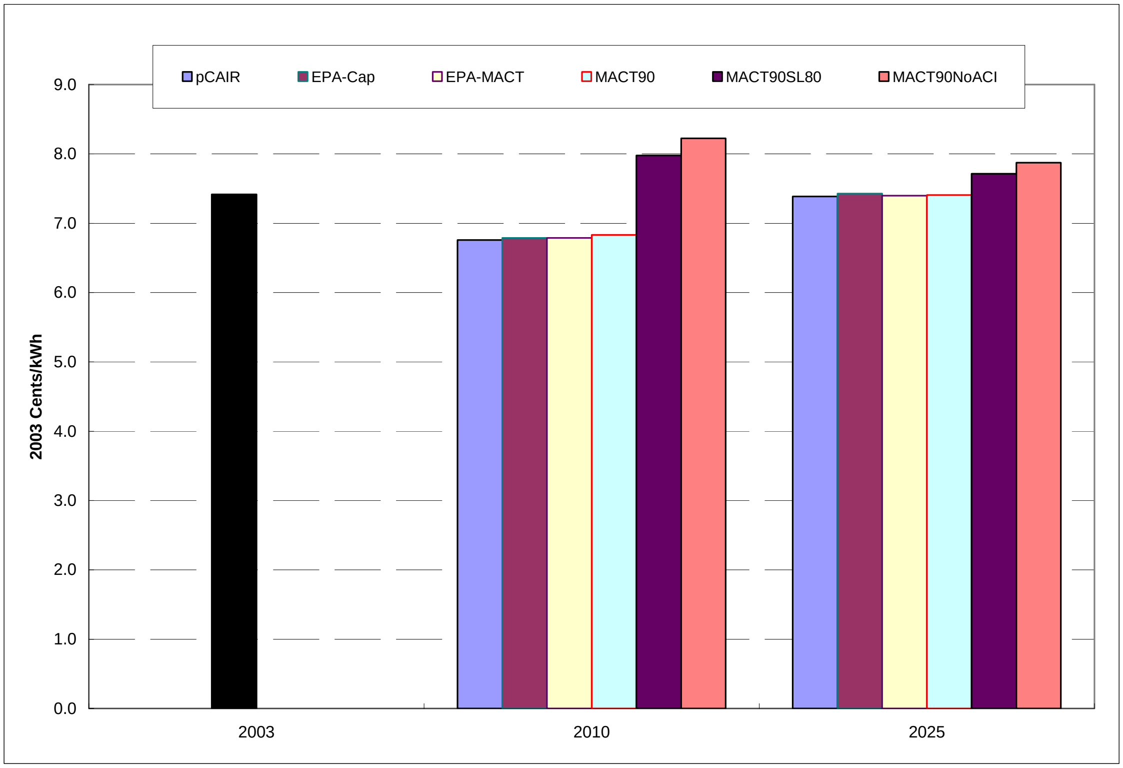
A similar pattern for natural gas wellhead prices is projected in the in the two cases with limited ACI performance or no ACI altogether – the price increase will be relatively large when the program first begins, but they will moderate over time as new resources are developed and brought to market. In 2010, natural gas wellhead prices are projected to be between 14 percent and 26 percent higher than in the pCAIR case. By 2025 the increases ranges from 2 percent to 5 percent.

Electricity Prices

The electricity price impacts of controlling mercury emissions generally increase with the level of mercury removal required (Figure 10). In 2010 and 2025, national average electricity prices in the EPA-Cap and EPA-MACT cases are projected to be less than 0.5 percent higher than prices in the pCAIR case. The size of these changes reflects the relatively modest mercury emissions reductions called for in the EPA-MACT case and the impact of the mercury safety valve which limits the mercury emissions reductions in the in the EPA-Cap case.

The electricity price changes in the 90-percent MACT cases are larger and very sensitive to the assumptions about the performance and availability of ACI mercury removal technologies. When ACI technologies are assumed to be available and able to achieve 90-percent mercury removal for all plant and coal types, a 90-percent MACT is projected to lead to electricity price impacts similar to those in the EPA-Cap and EPA-MACT cases. In the 90-percent MACT cases that assume limited ACI performance or no ACI, the increase in electricity prices in 2010 are projected to range between 18 percent and 22 percent. By 2025, the electricity price increases in these cases are projected to be smaller, ranging between 4 percent and 7 percent. The stronger impacts in 2010 result from the sharp impact on coal and natural gas markets when the MACT requirement takes effect in 2008. The shift from subbituminous and lignite coals to bituminous coals, natural gas, and renewables is so rapid that prices increase sharply in the near term. Over time, new supplies of the various fuels can be developed and prices would be expected to moderate. However, caution should be used when viewing the price results in these cases, because predicting market responses to the fuel consumption shifts expected in these two cases has considerable uncertainty.

Figure 10. Electricity Prices
(2003 cents per kilowatthour)

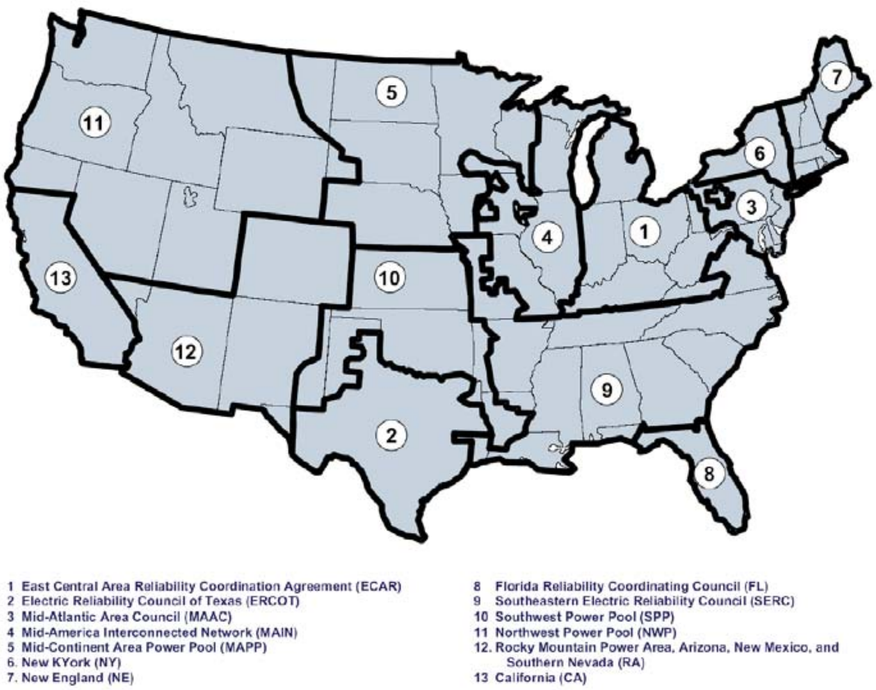


Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

Regional electricity prices are generally expected to follow the national pattern, with small changes expected in the EPA-Cap and EPA-MACT cases, and larger changes in the cases with a 90-percent MACT, particularly those where commercialized technologies capable of removing 90-percent of the mercury from all plant and coal types are not assumed to be available (Figures

11, 12 and 13). In the two 90-percent MACT cases without commercialized technologies capable of 90-percent mercury removal on all plant and coal types, electricity prices are projected to be significantly higher in all regions, particularly in the near term. The largest regional price increases, in absolute terms, are expected in the MAPP, SPP, and RA regions, which all rely heavily on subbituminous coal. In these three regions, the 2010 electricity price increases are projected to approach 2.5 cents per kilowatthour. In percentage terms, their electricity prices in 2010 are projected to be as much as 45 percent, 36 percent, and 33 percent higher, respectively, than in the pCAIR case projections. By 2025, the price changes in these cases are projected to moderate as new fuel supplies are developed, but prices in the MAPP and SPP are still projected to be more than 0.8 cents per kilowatthour than those in the pCAIR case.

Figure 11. Electricity Supply Regions

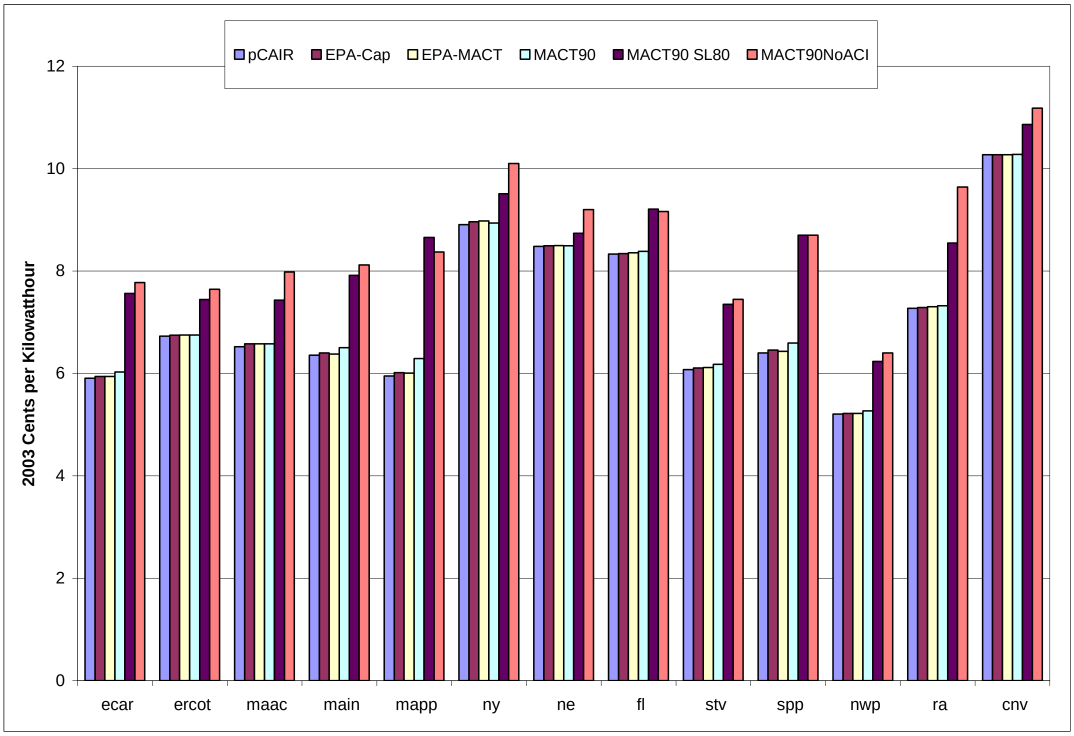


Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

Resource Costs

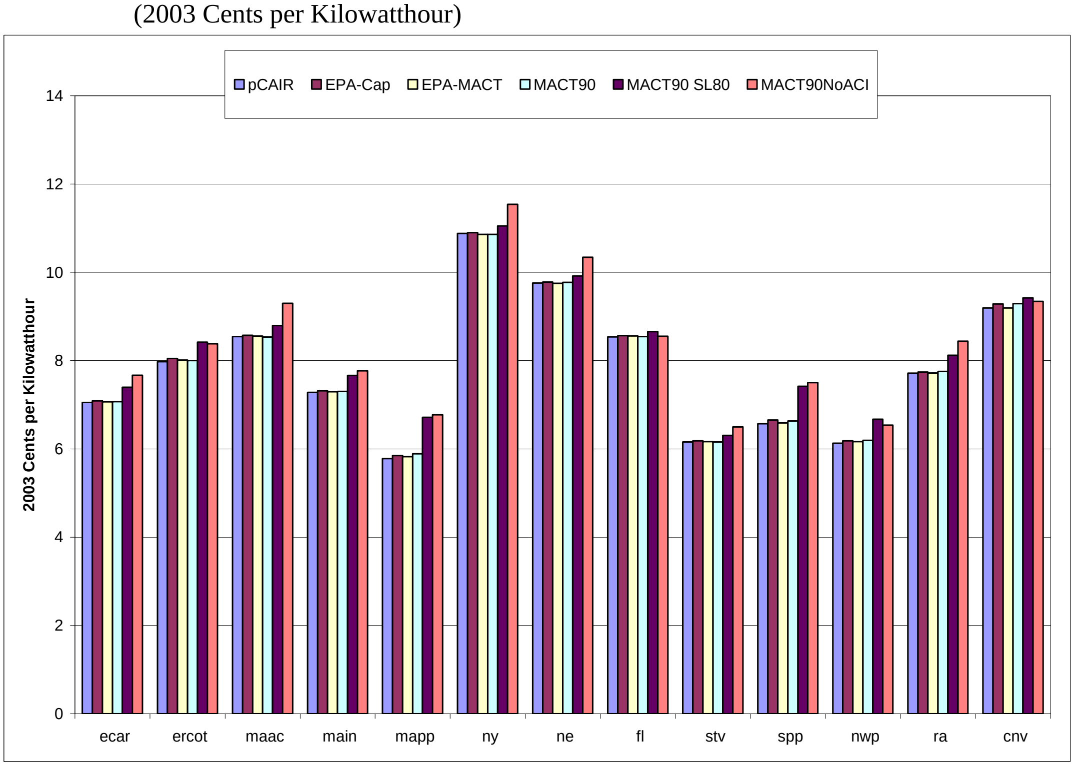
The relative impact on resource costs in each of the cases generally follows the electricity price impacts discussed previously. In general, the resource cost impacts of controlling mercury increase as the mercury removal required grows. The one exception to this rule occurs in the EPA-MACT case, where the increase in resource costs is larger than in the EPA-Cap case, even though mercury emissions are lower in the EPA-Cap case. The discounted resource costs and safety valve payments are projected to be $2 billion in the EPA-Cap case and $8 billion in the EPA-MACT (Figure 11). This counter intuitive result occurs because the cap and trade strategy in the EPA-Cap case allows power plant operators to reduce mercury emissions at the plants where it is most economical. Conversely, in the EPA-MACT case, some plants where it is relatively expensive to reduce mercury emissions are required to install equipment to make emissions reductions.

Figure 12. Regional Electricity Prices in 2010
(2003 Cents per Kilowatthour)



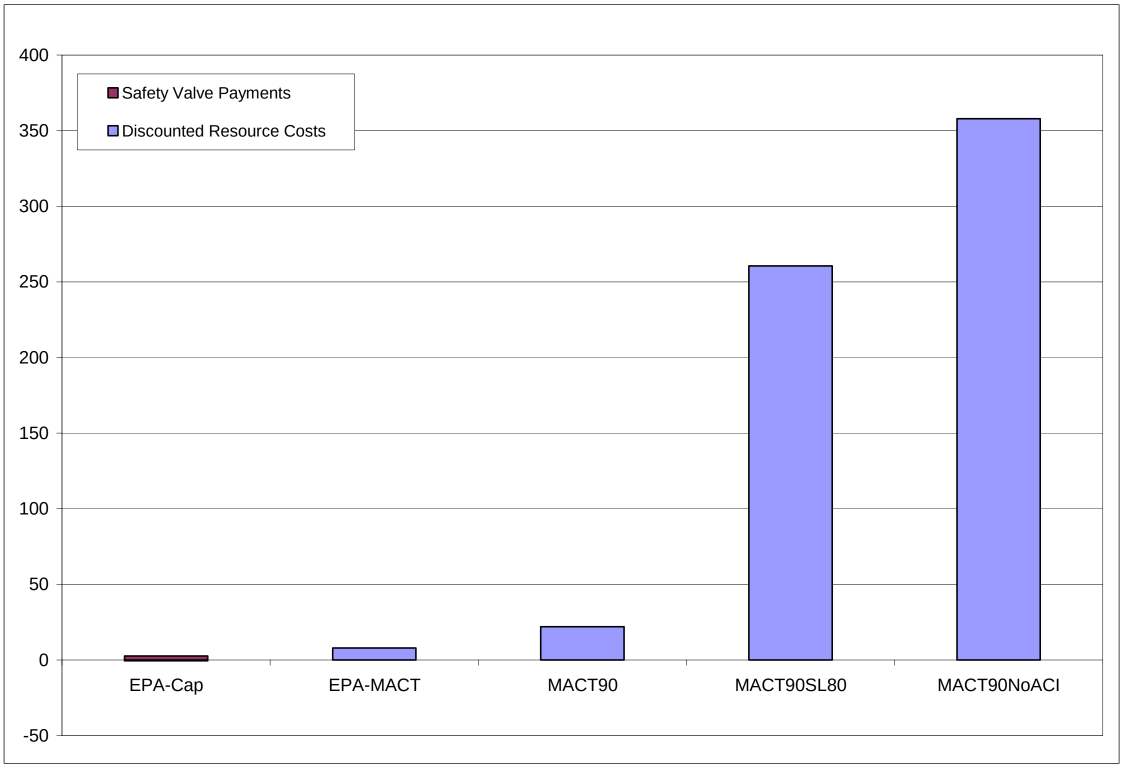
Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

Figure 13. Regional Electricity Prices in 2025
(2003 Cents per Kilowatthour)



Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

Figure 14. Discounted Resource Costs and Safety Valve Payments
(billion 2003 dollars)



Note: Costs cover 2005 through 2025 discounted at 7 percent.
Source: National Energy Modeling System runs, cair2005.d010505a, cair2005_cap.d010405b, cair2005_m29.d010505a, cair2005_m90.d010405a, cair2005_m90sl.d010505a, cair2005_m90na.d010505a.

In the 90-percent MACT cases, the assumptions about the availability and performance of ACI technologies lead to a wide range in projected resource cost impacts. In the 90-percent MACT case where ACI technologies are assumed to be available and able to achieve 90 percent mercury removal for all plant and coal types, discounted resource costs are projected to increase by $22 billion, roughly 10 times the cost increase projected in the EPA-Cap case and 3 times the cost increase expected in the EPA-MACT case. As noted above, even with these higher resource costs, the electricity price impacts of the MACT90 case are similar to those in the EPA-Cap and EPA-MACT cases. This occurs because the coal plants that incur these costs are not the plants that will set electricity prices during most hours. The resource cost impacts of a 90-percent MACT with limited ACI performance or without ACI are much higher still, ranging between $261 billion and $358 billion. The higher costs in these two cases reflect the costs of shifting away from relatively inexpensive subbituminous and lignite coals to other more expensive fuels. As mentioned previously, caution should be used when interpreting the near-term market price impacts from these scenarios.

Because of the sensitivity of the results in the 90-percent MACT cases to assumptions about ACI availability and performance, an additional sensitivity case was prepared. In this case it was assumed that plants using subbituminous and lignite coals could achieve 90 percent mercury removal by installing the full array of SO_2, NO_x and mercury controls. In other words, if they installed SO_2 scrubbers in combination with NO_x SCRs, and ACI systems to reduce mercury, they could achieve 90 percent overall mercury removal. However, because the mercury co-benefits of SO_2 scrubbers and NO_x SCRs on plants using subbituminous coals are relatively low, only 27 percent for plants with cold side electrostatic precipitators for particulate control, substantial performance is still needed from ACI systems. To achieve an overall mercury removal rate of 90 percent on a plant with 27 percent co-benefit removal, the ACI system would have to remove 86 percent of the remaining mercury.[7] As expected, this case showed greater reliance on SO_2 scrubbers and NO_x SCRs than the MACT90 case. About 173 gigawatts of SO_2 scrubbers and 186 gigawatts of NO_x SCRs were added, much higher than the 133 gigawatts and 138 gigawatts added, respectively, in the MACT90 case. It also showed much less switching out of western coal than was seen in the 90-percent MACT cases with limited ACI performance or no ACI. The resource costs impacts, $46 billion, were more than twice those in the MACT90 case, but substantially below those in the 90-percent MACT cases with limited ACI performance or no ACI.

Uncertainties

As with any projection, especially those that look out beyond a few years, there are considerable uncertainties. It is impossible to predict how existing generation or emissions control technologies might evolve in cost and performance or what currently unknown technologies might emerge to play unexpectedly important roles in the market. Of particular concern in this analysis are the cost and performance of technologies to remove mercury.

In recent years, substantial information has been gathered on the factors influencing mercury emissions at existing plants – i.e., mercury content of coal, coal rank, coal chlorine content, power plant particulate, SO_2, and NO_x control systems, etc. – but significant uncertainty remains. Experts at the EPA and the U.S. Department of Energy have different views on the mercury removal rates that should be assigned to particular plant configurations using various coals. Often their analyses use the same data sources, but because of variability in the data and their interpretation, they reach different conclusions. The understanding of what contributes to mercury emissions will likely improve in coming years as research efforts continue, but the outcome of these efforts is unknown.

One particular area of uncertainty concerns the role that NO_x control devices, SCRs, play in removing mercury from lower rank coals (subbituminous and lignite). Evidence suggests that when combined with a wet scrubber for SO_2 removal, they do enhance mercury removal in plants using bituminous coals. The same has not been found to be true for the lower rank coals but research is ongoing. Another area of uncertainty is the cost and performance of mercury removal systems. Supplemental fabric filter systems using ACI are expected to be a key technology in removing mercury. Tests of such systems have demonstrated their ability to remove mercury from bituminous coals, but full-scale tests on subbituminous and lignite coals are only now being performed.

This analysis presents several cases with alternative assumptions about the performance and availability of these systems. As the results show, if a relatively stringent mercury emissions cap is imposed, the performance of these systems will be a key driver of the market response. Two critical issues in any efforts to control mercury will be the timing and flexibility of the control program. Substantial efforts are now underway to develop and test economical mercury control

[7] This is calculated as follows: (1-0.27) X (1-0.86) = (1-0.90) or 0.10, 10 percent of the coal entering the plant will exit in the flue gases.

technologies. However, it may take several years before these efforts bear fruit. As a result, a control program that requires relatively stringent near term reductions may be difficult to address. In addition, while it is too early to say, it may turn out that it is very difficult to remove mercury from some plant and coal types. A control strategy that allows flexibility to achieve reductions where they are most economical would address this problem.

Appendix A

Requesting Letter

United States Senate

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
WASHINGTON, DC 20510-6175

September 14, 2004

The Honorable Guy F. Caruso
Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Administrator:

As part of our nation's continuing effort to improve air quality, the Environmental Protection Agency (EPA) proposed regulations to control mercury emissions from coal-fired power plants in December 2003. Some critics of the proposal contend that the rule should require each coal-fired electric generating unit to reduce its emissions of mercury by 90 percent or more by 2008 under the maximum achievable control technology (MACT) provisions in Section 112 of the Clean Air Act as amended – asserting that current technology can achieve such reductions and at reasonable cost. The Administration has proposed a cap and trade system, as its preferred approach, that would reduce emissions 69 percent. Alternately, it has proposed MACT standards that would require emission reductions of 29 percent.

In order to assess the relative cost impacts of each of these scenarios, we hereby request the Energy Information Administration to undertake analyses of these different approaches, comparing the EPA proposed cap and trade system, EPA alternate proposed MACT approach, a plant-by-plant 90 percent control MACT approach, and the approach recommended by environmental group stakeholders in the formal recommendations to the Clean Air Act Advisory Committee by its workgroup studying the mercury issue.

Please use the best information available, including data collected from the Information Collection Request I, II, and III. Please assume no new nuclear plant construction for the next two decades. Additionally, for purposes of control technology emission factors, please use commercially demonstrated technology or technology where the vendor provides financially backed guarantees indemnifying the purchaser for failure to control at expected levels. For purposes of this analysis, please take into consideration compliance strategies for reducing sulfur dioxide and nitrogen oxides that may be undertaken to comply with EPA's proposed Clean Air Interstate Rule (CAIR).

We are particularly interested that the following components be included in the analysis for each approach:

1. The marginal cost of reducing mercury (provide regional information where appropriate);
2. The type, commercial availability, and amount of emissions control equipment required;
3. The total resource cost (in present value terms as well as annual costs in relevant years);

Letter to Administrator Caruso
September 14, 2004
Page 2

4. The impact on energy production (coal, natural gas, oil, renewable, etc.) and energy prices regionally and nationally;
5. The impact on residential and industrial electric and natural gas consumers;
6. The impact on macroeconomic activity and national and regional coal employment; and
7. The change in reliability of the electric industry within each grid.

Any further details of the analysis can be addressed with John Shanahan at (202) 224-8072 and Brian Mormino at (202) 224-8098. I would appreciate it if you would provide the detailed analysis by October 15th, 2004 to assist the Committee in preparation for hearings. Thank you in advance for your cooperation. This analysis will be essential to ensuring an informed debate on the mercury emission issue.

Sincerely,

George V. Voinovich
Chairman
Subcommittee on Clean Air,
Climate Change, and Nuclear Safety

James M. Inhofe
Chairman
Committee on Environment
and Public Works

Appendix B

Interim Response

Department of Energy
Washington, DC 20585

October 20, 2004

The Honorable James M. Inhofe
Chairman
Committee on Environment and Public Works
U.S. Senate
Washington, D.C. 20510-6175

Dear Mr. Chairman:

This is in response to your letter of September 14, 2004, which describes several different proposals for reducing power plant mercury emissions and requests that the Energy Information Administration (EIA) prepare an analysis of these different approaches. Your letter also asks that our analysis assume compliance with the sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emission limits proposed in the Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) and that only "commercially demonstrated technology or technology where the vendor provides financially backed guarantees indemnifying the purchaser for failure to control to expected levels" should be assumed.

While we will do our best to complete this work as expeditiously as possible, we cannot meet the requested delivery date. Because significant enhancements to EIA's modeling system are needed to address your request, we expect that we will not be able to respond in full until early February 2005. In recent discussions, your staff has indicated that you have a particularly urgent need for any preliminary insights we could offer regarding the status of mercury control technologies and the possible implications of establishing a 90-percent maximum achievable control technology (MACT) requirement for all coal-fired units. Pending completion of the full analysis, the remainder of this letter outlines our present understanding of these matters.

At this time, there are two main approaches being considered for controlling power plant mercury emissions; 1) reducing mercury emissions using technologies primarily designed to remove SO_2, NO_x, and particulate emissions (often called co-benefit reductions), and 2) reducing mercury emissions using technologies specifically designed to reduce mercury. The attached table provides the emissions modification factors (EMFs) used in recent EIA and EPA modeling work for different power plant configurations and coals. The percent of mercury removed is calculated by subtracting the EMFs from 1. For example, an EMF of 0.05 implies 95-percent mercury removal. As shown, for EIA, the assumed percentage of mercury removed varies from as low as 0 percent for many plant configurations using lignite coal to as high as 95 percent for several plant configurations using bituminous coals. Both sets of EMFs in the table show that no coal plant configuration using subbituminous or lignite coals is assumed to be able to comply with a 90-percent MACT using SO_2, NO_x, or particulate control technologies (i.e., co-benefit reductions).

In order to continue to meet electric generating requirements and comply with a 90-percent mercury MACT at coal plants without using technologies specifically designed to reduce mercury, companies with plants that currently burn subbituminous or lignite coals would have to switch to bituminous coals and add any needed NO_x or SO_2 controls to reduce mercury emissions by 90 percent. This would require major changes in coal supply patterns, because subbituminous and lignite coals together accounted for roughly 50 percent of U.S. coal production in 2003. Alternatively, they could reduce their use of coal and increase their use of natural gas and renewable fuels or turn to mercury-specific control technologies.

While many approaches are being considered, the most common technology discussed to remove mercury from coal plants is activated carbon injection (ACI). ACI systems have been widely deployed in other industries, mainly in waste-to-energy plants (municipal solid waste (MSW) plants). In those applications they have achieved mercury removal rates in excess of 90 percent. However, ACI systems are only now being tested on U.S. coal plants, whose characteristics will tend to make mercury removal tougher than in MSW plants. For one thing, coal plants are typically much bigger with more flue gas to treat. They also have much lower concentrations of mercury in the untreated gas, and it is questionable whether similar removal levels will be achievable for all coals. Sulfur and trace elements in U.S. coals may also pose problems that will have to be resolved. Programs in the Department of Energy's Office of Fossil Energy are actively exploring these issues.

Because of these issues, the performance of these systems on coal plants and the guarantees that vendors would be willing to provide today are very uncertain. Vendors would likely be very conservative regarding guarantees until they have experience, and some problems could arise that limit the performance of these systems on particular plants or coals. As a result, depending on the stringency of the MACT standard imposed and when it is imposed, it might be hard or costly for some plants to get a guarantee that they could meet it.

It should be pointed out that the understanding of this technology is changing rapidly. EIA normally assumes that this technology will be available in the mid-term as might be required to comply with the 2010 or 2018 mercury emission caps called for in the Clear Skies Act of 2003. Whether current ACI systems for coal plants would meet the analysis request requirement for a "commercially demonstrated technology" with performance guarantees for deployment in the 2007 timeframe is questionable. The status of ACI technology together with many other factors will influence the performance guarantees that vendors might be willing to offer. These factors include the contract terms of the guarantee (i.e., the potential liability on the vendor) as well as the existence of other control technologies that would lower the percentage reduction needed from ACI. These issues, which depend on individual plant characteristics, are very difficult to address.

Under the "worst case" scenario in which no ACI systems for coal plants are commercially available by 2007, it would be very difficult for coal plant operators using subbituminous or lignite coals to comply with a 90-percent MACT that takes effect at that time. The imposition of such a MACT would be expected to lead to a significant shift towards higher-priced bituminous coals and shift from coal to natural gas and renewable fuels. Because coal plants currently supply over 50 percent of the electricity generated in the United States, these shifts could lead to significant costs to the industry and higher electricity prices to consumers. The large and rapid shifts expected in markets for coal and natural gas in this scenario create modeling challenges that will need to be analyzed and resolved in order to produce reportable model runs.

If you have any further questions, please do not hesitate to contact me on (202) 586-4361. Alternatively, your staff can contact John J. Conti, Acting Director, Office of Integrated Analysis and Forecasting, at (202) 586-2222.

Sincerely,

Guy F. Caruso
Administrator
Energy Information Administration

Attachment

cc: The Honorable George V. Vionovich

Table 1. Mercury Emission Modification Factors Used in Recent EIA and EPA Modeling Work

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NO_x Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	---	0.11	0.27	1.00	0.11	0.27	1.00
Wet	BH	None	0.05	0.27	0.64	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.64	0.10	0.15	0.56
Dry	BH	---	0.05	0.75	1.00	0.05	0.75	1.00
None	CSE	---	0.64	0.97	1.00	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.58	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.58	0.10	0.34	0.56
Dry	CSE	---	0.64	0.65	1.00	0.64	0.65	1.00
None	HSE/Oth	---	0.90	0.94	1.00	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	1.00	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.64	0.10	0.75	1.00
Dry	HSE/Oth	---	0.60	0.85	1.00	0.60	0.85	1.00

Notes: SO_2 Controls – Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH = fabric filter/baghouse, CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction, --- = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations.

Sources: EPA EMFs, http://www.epa.gov/clearskies/technical.html. EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/ HSE/Oth /SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Appendix C

pCAIR, EPA-Cap and EPA-MACT Run Tables

Table C1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Production							
Crude Oil and Lease Condensate	12.03	12.75	12.75	12.75	10.01	9.99	9.98
Natural Gas Plant Liquids	2.34	2.67	2.67	2.67	2.77	2.77	2.74
Dry Natural Gas	19.58	21.02	21.06	21.01	22.10	22.07	22.09
Coal	22.66	24.92	24.80	24.86	29.56	29.38	29.51
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67
Renewable Energy[1]	5.91	6.90	6.91	6.90	8.41	8.44	8.36
Other[2]	0.93	0.96	0.96	0.96	0.82	0.82	0.08
Total	**71.44**	**77.71**	**77.64**	**77.64**	**82.33**	**82.14**	**81.42**
Imports							
Crude Oil[3]	21.08	24.66	24.66	24.67	35.24	35.23	35.27
Petroleum Products[4]	5.16	6.06	6.04	6.03	8.12	8.15	6.90
Natural Gas	4.02	5.75	5.76	5.77	9.99	10.08	10.04
Other Imports[5]	0.69	0.93	0.93	0.93	1.23	1.23	1.23
Total	**30.95**	**37.40**	**37.39**	**37.40**	**54.58**	**54.68**	**53.44**
Exports							
Petroleum[6]	2.13	2.15	2.15	2.14	2.32	2.32	2.27
Natural Gas	0.70	0.65	0.65	0.65	0.83	0.83	0.83
Coal	1.12	1.06	1.06	1.06	0.65	0.67	0.65
Total	**3.95**	**3.86**	**3.86**	**3.85**	**3.80**	**3.82**	**3.75**
Discrepancy[7]	**0.19**	**0.03**	**0.03**	**0.03**	**0.13**	**0.13**	**-1.77**
Consumption							
Petroleum Products[8]	39.09	44.81	44.80	44.80	54.29	54.29	54.24
Natural Gas	22.54	26.19	26.24	26.20	31.44	31.50	31.49
Coal	22.71	24.77	24.65	24.71	30.14	29.94	30.09
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67
Renewable Energy[1]	5.91	6.90	6.91	6.90	8.41	8.44	8.36
Other[9]	0.02	0.05	0.05	0.05	0.04	0.04	0.04
Total	**98.24**	**111.21**	**111.14**	**111.15**	**132.99**	**132.88**	**132.88**
Net Imports - Petroleum	**24.10**	**28.57**	**28.55**	**28.56**	**41.04**	**41.06**	**39.90**
Prices (2003 dollars per unit)							
World Oil Price (dollars per barrel)[10]	27.73	25.00	25.00	25.00	30.31	30.31	30.31
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.66	3.67	3.68	4.81	4.82	4.82
Coal Minemouth Price (dollars per ton)	17.93	17.31	17.54	17.28	17.87	18.55	17.74
Average Electricity Price (cents per kilowatthour)	7.4	6.8	6.8	6.8	7.4	7.4	7.4

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table B18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Energy Consumption							
Residential							
Distillate Fuel	0.96	0.90	0.90	0.90	0.77	0.77	0.77
Kerosene	0.07	0.09	0.09	0.09	0.09	0.09	0.09
Liquefied Petroleum Gas	0.54	0.57	0.57	0.57	0.67	0.67	0.67
Petroleum Subtotal	1.58	1.56	1.56	1.56	1.53	1.53	1.53
Natural Gas	5.25	5.68	5.68	5.68	6.16	6.16	6.16
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.40	0.40	0.38	0.38	0.38
Electricity	4.37	5.00	5.00	5.00	6.15	6.15	6.15
Delivered Energy	**11.61**	**12.65**	**12.65**	**12.65**	**14.23**	**14.22**	**14.22**
Electricity Related Losses	9.71	10.80	10.77	10.78	12.33	12.30	12.31
Total	**21.32**	**23.45**	**23.42**	**23.43**	**26.56**	**26.52**	**26.54**
Commercial							
Distillate Fuel	0.52	0.62	0.62	0.62	0.77	0.77	0.77
Residual Fuel	0.07	0.07	0.07	0.07	0.08	0.08	0.08
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.86	0.86	0.86	1.02	1.02	1.02
Natural Gas	3.22	3.48	3.48	3.48	4.16	4.16	4.16
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	4.99	4.99	4.99	7.10	7.09	7.09
Delivered Energy	**8.29**	**9.51**	**9.51**	**9.51**	**12.46**	**12.45**	**12.45**
Electricity Related Losses	9.18	10.77	10.74	10.75	14.22	14.19	14.20
Total	**17.47**	**20.28**	**20.26**	**20.26**	**26.68**	**26.64**	**26.66**
Industrial[4]							
Distillate Fuel	1.03	1.04	1.04	1.04	1.19	1.19	1.19
Liquefied Petroleum Gas	2.09	2.30	2.30	2.30	2.73	2.73	2.73
Petrochemical Feedstock	1.32	1.48	1.48	1.48	1.56	1.56	1.56
Residual Fuel	0.28	0.33	0.33	0.33	0.37	0.38	0.38
Motor Gasoline[2]	0.31	0.31	0.31	0.31	0.37	0.37	0.37
Other Petroleum[5]	4.30	4.69	4.69	4.69	5.24	5.23	5.23
Petroleum Subtotal	9.31	10.16	10.16	10.16	11.47	11.46	11.47
Natural Gas	7.19	8.09	8.09	8.09	9.30	9.31	9.30
Lease and Plant Fuel[6]	1.15	1.21	1.21	1.20	1.29	1.29	1.29
Natural Gas Subtotal	8.34	9.30	9.30	9.29	10.59	10.60	10.59
Metallurgical Coal	0.67	0.55	0.55	0.55	0.37	0.37	0.37
Steam Coal	1.39	1.42	1.42	1.42	1.41	1.41	1.41
Net Coal Coke Imports	0.05	0.05	0.05	0.05	0.05	0.04	0.04
Coal Subtotal	2.11	2.03	2.03	2.03	1.83	1.83	1.83
Renewable Energy[7]	1.79	2.07	2.06	2.06	2.49	2.49	2.49
Electricity	3.31	3.77	3.77	3.77	4.36	4.36	4.36
Delivered Energy	**24.86**	**27.32**	**27.32**	**27.31**	**30.74**	**30.73**	**30.74**
Electricity Related Losses	7.35	8.13	8.11	8.12	8.74	8.72	8.73
Total	**32.21**	**35.45**	**35.43**	**35.44**	**39.48**	**39.45**	**39.46**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Transportation							
Distillate Fuel[8]	5.54	6.94	6.93	6.94	9.04	9.03	9.04
Jet Fuel[9]	3.26	4.04	4.04	4.04	4.89	4.89	4.89
Motor Gasoline[2]	16.64	19.14	19.14	19.14	24.04	24.04	24.00
Residual Fuel	0.62	0.56	0.56	0.56	0.58	0.58	0.58
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.31	0.31	0.31
Petroleum Subtotal	26.31	30.99	30.98	30.99	38.95	38.94	38.90
Pipeline Fuel Natural Gas	0.65	0.70	0.70	0.70	0.84	0.84	0.84
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.12	0.12	0.12
Delivered Energy	**27.07**	**31.84**	**31.83**	**31.84**	**40.02**	**40.02**	**39.98**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.24	0.24	0.24
Total	**27.24**	**32.03**	**32.03**	**32.03**	**40.26**	**40.26**	**40.22**
Delivered Energy Consumption for All Sectors							
Distillate Fuel	8.04	9.50	9.49	9.50	11.77	11.77	11.77
Kerosene	0.11	0.14	0.14	0.14	0.13	0.13	0.13
Jet Fuel[9]	3.26	4.04	4.04	4.04	4.89	4.89	4.89
Liquefied Petroleum Gas	2.75	3.03	3.03	3.03	3.59	3.59	3.59
Motor Gasoline[2]	16.98	19.50	19.49	19.49	24.45	24.45	24.40
Petrochemical Feedstock	1.32	1.48	1.48	1.48	1.56	1.56	1.56
Residual Fuel	0.97	0.97	0.97	0.97	1.03	1.04	1.03
Other Petroleum[12]	4.52	4.93	4.93	4.93	5.53	5.52	5.53
Petroleum Subtotal	37.96	43.57	43.56	43.57	52.96	52.95	52.91
Natural Gas	15.68	17.32	17.31	17.31	19.73	19.74	19.73
Lease and Plant Fuel Plant[6]	1.15	1.21	1.21	1.20	1.29	1.29	1.29
Pipeline Natural Gas	0.65	0.70	0.70	0.70	0.84	0.84	0.84
Natural Gas Subtotal	17.48	19.22	19.22	19.21	21.86	21.86	21.86
Metallurgical Coal	0.67	0.55	0.55	0.55	0.37	0.37	0.37
Steam Coal	1.50	1.53	1.53	1.53	1.52	1.52	1.52
Net Coal Coke Imports	0.05	0.05	0.05	0.05	0.05	0.04	0.04
Coal Subtotal	2.22	2.14	2.14	2.14	1.93	1.93	1.93
Renewable Energy[13]	2.28	2.55	2.55	2.55	2.97	2.97	2.97
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.85	13.85	13.84	17.73	17.71	17.72
Delivered Energy	**71.82**	**81.33**	**81.32**	**81.31**	**97.45**	**97.42**	**97.39**
Electricity Related Losses	26.42	29.88	29.82	29.84	35.53	35.46	35.49
Total	**98.24**	**111.21**	**111.14**	**111.15**	**132.99**	**132.88**	**132.88**
Electric Power[14]							
Distillate Fuel	0.33	0.41	0.41	0.40	0.47	0.47	0.46
Residual Fuel	0.80	0.83	0.84	0.83	0.86	0.87	0.87
Petroleum Subtotal	1.13	1.24	1.24	1.23	1.33	1.34	1.33
Natural Gas	5.06	6.97	7.02	6.99	9.58	9.63	9.62
Steam Coal	20.49	22.64	22.51	22.57	28.20	28.01	28.15
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67
Renewable Energy[15]	3.64	4.35	4.36	4.35	5.45	5.48	5.40
Electricity Imports	0.02	0.05	0.05	0.05	0.04	0.04	0.04
Total	**38.30**	**43.73**	**43.67**	**43.68**	**53.27**	**53.16**	**53.21**

Table C2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Total Energy Consumption							
Distillate Fuel	8.37	9.91	9.90	9.90	12.24	12.24	12.23
Kerosene	0.11	0.14	0.14	0.14	0.13	0.13	0.13
Jet Fuel[9]	3.26	4.04	4.04	4.04	4.89	4.89	4.89
Liquefied Petroleum Gas	2.75	3.03	3.03	3.03	3.59	3.59	3.59
Motor Gasoline[2]	16.98	19.50	19.49	19.49	24.45	24.45	24.40
Petrochemical Feedstock	1.32	1.48	1.48	1.48	1.56	1.56	1.56
Residual Fuel	1.77	1.80	1.80	1.80	1.90	1.91	1.90
Other Petroleum[12]	4.52	4.93	4.93	4.93	5.53	5.52	5.53
Petroleum Subtotal	39.09	44.81	44.80	44.80	54.29	54.29	54.24
Natural Gas	20.74	24.28	24.33	24.30	29.31	29.37	29.36
Lease and Plant Fuel[6]	1.15	1.21	1.21	1.20	1.29	1.29	1.29
Pipeline Natural Gas	0.65	0.70	0.70	0.70	0.84	0.84	0.84
Natural Gas Subtotal	22.54	26.19	26.24	26.20	31.44	31.50	31.49
Metallurgical Coal	0.67	0.55	0.55	0.55	0.37	0.37	0.37
Steam Coal	21.99	24.17	24.04	24.10	29.72	29.52	29.67
Net Coal Coke Imports	0.05	0.05	0.05	0.05	0.05	0.04	0.04
Coal Subtotal	22.71	24.77	24.65	24.71	30.14	29.94	30.09
Nuclear Power	7.97	8.49	8.49	8.49	8.67	8.67	8.67
Renewable Energy[16]	5.91	6.90	6.91	6.90	8.41	8.44	8.36
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.05	0.05	0.05	0.04	0.04	0.04
Total	**98.24**	**111.21**	**111.14**	**111.15**	**132.99**	**132.88**	**132.88**
Energy Use and Related Statistics							
Delivered Energy Use	71.82	81.33	81.32	81.31	97.45	97.42	97.39
Total Energy Use	98.24	111.21	111.14	111.15	132.99	132.88	132.88
Population (millions)	291.39	310.12	310.12	310.12	350.64	350.64	350.64
Gross Domestic Product (billion 2000 dollars)	10381	13078	13077	13077	20287	20286	20285
Carbon Dioxide Emissions (million metric tons)	5788.7	6612.5	6601.9	6606.5	8019.4	8001.7	8013.1

[1]Includes wood used for residential heating. See Table B4 and/or Table B17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table B18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Residential	**15.81**	**14.51**	**14.56**	**14.55**	**16.24**	**16.30**	**16.26**
Primary Energy[1]	9.68	8.36	8.37	8.37	9.64	9.65	9.64
Petroleum Products[2]	11.27	10.40	10.43	10.40	11.93	11.93	11.93
Distillate Fuel	9.57	8.22	8.26	8.22	9.12	9.11	9.11
Liquefied Petroleum Gas	14.58	14.25	14.25	14.25	15.65	15.65	15.65
Natural Gas	9.22	7.82	7.82	7.83	9.08	9.10	9.09
Electricity	25.42	23.43	23.52	23.52	24.50	24.62	24.54
Commercial	**15.63**	**14.00**	**14.06**	**14.05**	**16.35**	**16.43**	**16.37**
Primary Energy[1]	7.92	6.82	6.83	6.83	7.83	7.85	7.84
Petroleum Products[2]	8.03	7.10	7.12	7.08	7.83	7.83	7.83
Distillate Fuel	7.03	6.25	6.28	6.24	7.06	7.05	7.05
Residual Fuel	4.96	4.26	4.26	4.26	5.06	5.06	5.06
Natural Gas	8.08	6.89	6.90	6.91	7.97	8.00	7.98
Electricity	23.24	20.39	20.48	20.48	22.68	22.82	22.71
Industrial[3]	**7.78**	**6.91**	**6.94**	**6.93**	**8.16**	**8.19**	**8.17**
Primary Energy	6.49	5.55	5.56	5.55	6.65	6.66	6.65
Petroleum Products[2]	8.29	7.23	7.24	7.22	8.37	8.37	8.36
Distillate Fuel	7.24	6.76	6.78	6.74	7.73	7.73	7.73
Liquefied Petroleum Gas	12.57	10.02	10.02	10.01	11.35	11.36	11.35
Residual Fuel	4.59	3.88	3.88	3.87	4.61	4.61	4.61
Natural Gas[4]	5.56	4.40	4.41	4.41	5.49	5.52	5.51
Metallurgical Coal	1.85	1.83	1.83	1.83	1.69	1.69	1.69
Steam Coal	1.55	1.55	1.56	1.55	1.59	1.62	1.59
Electricity	15.03	14.24	14.32	14.33	15.96	16.08	16.01
Transportation	**11.46**	**10.90**	**10.94**	**10.90**	**11.46**	**11.46**	**11.46**
Primary Energy	11.43	10.88	10.92	10.87	11.44	11.44	11.43
Petroleum Products[2]	11.43	10.88	10.92	10.88	11.44	11.44	11.44
Distillate Fuel[5]	10.92	10.73	10.76	10.70	10.84	10.84	10.85
Jet Fuel[6]	6.46	6.22	6.25	6.21	6.93	6.92	6.92
Motor Gasoline[7]	12.93	12.26	12.30	12.26	12.81	12.81	12.81
Residual Fuel	4.49	3.74	3.74	3.74	4.55	4.55	4.55
Liquefied Petroleum Gas[8]	16.65	15.24	15.24	15.24	16.25	16.26	16.25
Natural Gas[9]	9.04	8.58	8.59	8.59	9.71	9.72	9.71
Ethanol (E85)[10]	16.23	17.09	17.12	17.10	18.20	18.19	18.19
Electricity	20.61	19.23	19.32	19.31	20.15	20.28	20.19
Average End-Use Energy	**11.50**	**10.61**	**10.65**	**10.63**	**11.87**	**11.90**	**11.88**
Primary Energy	9.32	8.59	8.61	8.59	9.55	9.55	9.55
Electricity	21.74	19.81	19.90	19.89	21.64	21.77	21.68
Electric Power[11]							
Fossil Fuel Average	2.24	2.08	2.09	2.09	2.45	2.50	2.48
Petroleum Products	5.28	4.56	4.57	4.56	5.48	5.47	5.47
Distillate Fuel	6.48	5.32	5.35	5.32	6.33	6.32	6.33
Residual Fuel	4.79	4.19	4.19	4.19	5.02	5.02	5.02
Natural Gas	5.46	4.30	4.31	4.31	5.45	5.49	5.48
Steam Coal	1.28	1.26	1.26	1.27	1.29	1.32	1.31

Table C3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections 2010			Projections 2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Average Price to All Users[12]							
Petroleum Products[2]	10.51	9.87	9.90	9.87	10.67	10.67	10.67
Distillate Fuel	9.90	9.49	9.52	9.47	10.02	10.02	10.03
Jet Fuel	6.46	6.22	6.25	6.21	6.93	6.92	6.92
Liquefied Petroleum Gas	13.04	10.99	10.99	10.99	12.34	12.34	12.34
Motor Gasoline[7]	12.93	12.25	12.29	12.24	12.80	12.80	12.80
Residual Fuel	4.66	3.99	3.99	3.99	4.80	4.80	4.80
Natural Gas	6.86	5.54	5.54	5.55	6.60	6.63	6.62
Coal	1.30	1.28	1.28	1.28	1.30	1.34	1.33
Ethanol (E85)[10]	16.23	17.09	17.12	17.10	18.20	18.19	18.19
Electricity	21.74	19.81	19.90	19.89	21.64	21.77	21.68
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)							
Residential	177.17	177.89	178.41	178.29	224.98	225.59	225.13
Commercial	128.15	132.01	132.48	132.42	202.30	203.12	202.49
Industrial	147.11	140.82	141.28	141.19	185.62	186.40	185.94
Transportation	302.59	339.54	340.54	339.28	449.08	449.00	448.48
Total Non-Renewable Expenditures	755.02	790.26	792.72	791.18	1061.99	1064.11	1062.04
Transportation Renewable Expenditures	0.02	0.03	0.03	0.03	0.08	0.08	0.08
Total Expenditures	**755.04**	**790.30**	**792.75**	**791.22**	**1062.06**	**1064.19**	**1062.12**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run CAIR2005.D010505A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Generation by Fuel Type							
Electric Power Sector[1]							
Power Only[2]							
Coal	1916	2139	2130	2133	2795	2774	2784
Petroleum	106	110	110	109	119	120	119
Natural Gas[3]	407	645	651	648	1055	1062	1062
Nuclear Power	764	813	813	813	830	830	830
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9
Renewable Sources[4]	318	393	394	393	450	451	447
Distributed Generation (Natural Gas)	0	0	0	0	3	3	3
Total	**3501**	**4092**	**4089**	**4087**	**5243**	**5232**	**5236**
Combined Heat and Power[5]							
Coal	34	33	33	34	33	32	35
Petroleum	7	6	6	6	7	7	7
Natural Gas	149	188	190	189	182	183	183
Renewable Sources	6	4	4	4	4	4	4
Total	**197**	**231**	**232**	**233**	**225**	**226**	**229**
Total Net Generation	**3699**	**4323**	**4322**	**4320**	**5468**	**5458**	**5465**
Less Direct Use	50	66	66	67	65	65	66
Net Available to the Grid	**3649**	**4257**	**4256**	**4254**	**5403**	**5393**	**5399**
Commercial and Industrial Generation[6]							
Coal	21	21	21	21	21	21	21
Petroleum	6	9	9	9	13	13	13
Natural Gas	76	100	100	101	178	181	179
Other Gaseous Fuels[7]	6	4	4	4	5	5	5
Renewable Sources[4]	35	43	43	43	55	55	55
Other[8]	10	10	10	10	10	10	10
Total	**153**	**187**	**187**	**187**	**282**	**285**	**283**
Less Direct Use	126	139	139	139	187	188	187
Total Sales to the Grid	**28**	**48**	**48**	**48**	**96**	**97**	**96**
Total Electricity Generation	**3852**	**4510**	**4509**	**4507**	**5750**	**5743**	**5748**
Total Net Generation to the Grid	**3677**	**4305**	**4304**	**4302**	**5498**	**5490**	**5495**
Net Imports	**5**	**14**	**14**	**14**	**12**	**12**	**12**
Electricity Sales by Sector							
Residential	1280	1466	1466	1465	1804	1801	1802
Commercial	1210	1462	1462	1461	2080	2077	2079
Industrial	969	1104	1104	1104	1278	1277	1278
Transportation	23	26	26	26	35	35	35
Total	**3481**	**4059**	**4059**	**4057**	**5197**	**5190**	**5194**
Direct Use	175	204	204	205	252	253	253
Total Electricity Use	**3657**	**4264**	**4263**	**4262**	**5449**	**5443**	**5447**
End-Use Prices[9] (2003 cents per kilowatthour)							
Residential	8.7	8.0	8.0	8.0	8.4	8.4	8.4
Commercial	7.9	7.0	7.0	7.0	7.7	7.8	7.8
Industrial	5.1	4.9	4.9	4.9	5.4	5.5	5.5
Transportation	7.0	6.6	6.6	6.6	6.9	6.9	6.9
All Sectors Average	**7.4**	**6.8**	**6.8**	**6.8**	**7.4**	**7.4**	**7.4**
Prices by Service Category[9] (2003 cents per kilowatthour)							
Generation	4.8	4.2	4.3	4.3	5.0	5.0	5.0
Transmission	0.5	0.6	0.6	0.6	0.7	0.7	0.7
Distribution	2.1	2.0	2.0	2.0	1.8	1.8	1.8

Table C4. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Electric Power Sector Emissions[1]							
Sulfur Dioxide (million tons)	10.59	5.79	5.78	5.63	3.90	3.84	3.83
Nitrogen Oxide (million tons)	4.12	2.28	2.26	2.27	2.20	2.20	2.21
Mercury (tons)	49.99	45.77	34.00	35.87	44.08	30.15	40.17

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), and supporting databases. 2003 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2003 prices: EIA, National Energy Modeling System run CAIR2005.D010505A. **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2003	Projections 2010 pCAIR	2010 EPA Cap	2010 EPA MACT	2025 pCAIR	2025 EPA Cap	2025 EPA MACT
Electric Power Sector[2]							
Power Only[3]							
Coal Steam	305.2	303.2	302.9	303.0	386.8	384.2	384.4
Other Fossil Steam[4]	128.6	119.4	119.4	119.4	98.1	98.0	98.3
Combined Cycle	106.9	136.1	136.0	136.0	196.5	198.1	198.1
Combustion Turbine/Diesel	124.8	132.5	132.5	132.5	180.3	180.1	180.2
Nuclear Power[5]	99.2	100.6	100.6	100.6	102.7	102.7	102.7
Pumped Storage	20.8	20.9	20.9	20.9	20.9	20.9	20.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	92.0	95.0	95.0	95.0	103.5	103.3	103.3
Distributed Generation[7]	0.0	0.4	0.4	0.4	6.8	6.9	7.1
Total	**877.5**	**908.0**	**907.7**	**907.6**	**1095.5**	**1094.2**	**1094.8**
Combined Heat and Power[8]							
Coal Steam	5.1	5.1	5.1	5.1	4.8	4.6	4.8
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	31.3	33.5	33.5	33.5	33.5	33.5	33.5
Combustion Turbine/Diesel	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**42.8**	**45.1**	**45.1**	**45.1**	**44.8**	**44.5**	**44.8**
Cumulative Planned Additions[9]							
Coal Steam	0.0	1.8	1.8	1.8	1.8	1.8	1.8
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	28.3	28.3	28.3	28.3	28.3	28.3
Combustion Turbine/Diesel	0.0	3.9	3.9	3.9	3.9	3.9	3.9
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	2.7	2.7	2.7	3.0	3.0	3.0
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**36.7**	**36.7**	**36.7**	**37.0**	**37.0**	**37.0**
Cumulative Unplanned Additions[9]							
Coal Steam	0.0	0.0	0.0	0.0	84.3	82.0	82.4
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	3.2	3.2	3.1	63.7	65.4	65.3
Combustion Turbine/Diesel	0.0	5.7	5.7	5.7	60.0	59.7	60.3
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	8.3	8.1	8.2
Distributed Generation[7]	0.0	0.4	0.4	0.4	6.8	6.9	7.1
Total	**0.0**	**9.4**	**9.4**	**9.3**	**223.1**	**222.1**	**223.2**
Cumulative Electric Power Sector Additions	**0.0**	**46.1**	**46.0**	**46.0**	**260.0**	**259.1**	**260.2**
Cumulative Retirements[10]							
Coal Steam	0.0	3.7	4.0	4.0	4.8	5.3	5.3
Other Fossil Steam[4]	0.0	9.3	9.3	9.3	30.5	30.6	30.4
Combined Cycle	0.0	0.1	0.1	0.1	0.2	0.2	0.2
Combustion Turbine/Diesel	0.0	1.9	1.9	1.9	8.4	8.2	8.8
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**15.1**	**15.4**	**15.4**	**44.0**	**44.5**	**44.7**
Total Electric Power Sector Capacity	**920.3**	**953.1**	**952.7**	**952.7**	**1140.2**	**1138.7**	**1139.6**

Table C5. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2003	Projections 2010 pCAIR	2010 EPA Cap	2010 EPA MACT	2025 pCAIR	2025 EPA Cap	2025 EPA MACT
End-Use Sector[11]							
Coal	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Petroleum	0.7	1.5	1.5	1.5	1.8	1.8	1.8
Natural Gas	14.4	17.4	17.4	17.4	27.9	28.2	28.1
Other Gaseous Fuels	1.8	1.5	1.5	1.5	1.7	1.7	1.7
Renewable Sources[6]	5.4	6.8	6.8	6.8	9.9	9.9	9.9
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.1**	**32.1**	**32.1**	**32.1**	**46.1**	**46.5**	**46.2**
Cumulative Capacity Additions[9]	**0.0**	**5.0**	**5.0**	**5.0**	**19.0**	**19.4**	**19.1**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.9 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak-load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2003.
[10]Cumulative total retirements after December 31, 2003.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model estimates and may differ slightly from official EIA data reports.
Sources: 2003 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C6. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Production							
Dry Gas Production[1]	19.07	20.46	20.50	20.46	21.52	21.49	21.51
Supplemental Natural Gas[2]	0.06	0.08	0.08	0.08	0.08	0.08	0.08
Net Imports	**3.24**	**4.97**	**4.99**	**5.00**	**8.95**	**9.03**	**8.99**
Canada	3.13	2.59	2.59	2.60	2.50	2.52	2.51
Mexico	-0.33	-0.14	-0.14	-0.14	-0.25	-0.25	-0.25
Liquefied Natural Gas[3]	0.44	2.52	2.53	2.53	6.70	6.76	6.74
Total Supply	**22.37**	**25.51**	**25.57**	**25.53**	**30.54**	**30.59**	**30.58**
Consumption by Sector							
Residential	5.10	5.52	5.52	5.52	5.99	5.98	5.98
Commercial	3.13	3.38	3.38	3.38	4.05	4.05	4.04
Industrial[4]	6.99	7.87	7.87	7.86	9.04	9.05	9.04
Electric Power[5]	4.96	6.83	6.88	6.86	9.39	9.44	9.43
Transportation[5]	0.02	0.06	0.06	0.06	0.11	0.11	0.11
Pipeline Fuel	0.64	0.68	0.68	0.68	0.82	0.82	0.82
Lease and Plant Fuel[7]	1.12	1.17	1.18	1.17	1.26	1.26	1.26
Total	**21.95**	**25.51**	**25.57**	**25.53**	**30.64**	**30.70**	**30.69**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[8]	**0.42**	**-0.00**	**-0.00**	**-0.00**	**-0.11**	**-0.11**	**-0.11**
Natural Gas Prices (2003 dollars per thousand cubic feet)							
Average Lower 48 Wellhead Price[9]	**4.98**	**3.66**	**3.67**	**3.68**	**4.81**	**4.82**	**4.82**
Delivered Prices							
Residential	9.49	8.04	8.05	8.06	9.35	9.36	9.35
Commercial	8.31	7.09	7.10	7.11	8.21	8.23	8.22
Industrial[4]	5.72	4.52	4.54	4.54	5.65	5.68	5.67
Electric Power[5]	5.57	4.38	4.39	4.40	5.56	5.60	5.59
Transportation[10]	9.31	8.82	8.84	8.84	9.99	10.00	9.99
Average[11]	**7.04**	**5.69**	**5.69**	**5.70**	**6.78**	**6.81**	**6.80**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 and 2001 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). Other 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004. 2003 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 transportation sector delivered prices are model results. **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C7. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Production[1]							
Appalachia	388	403	403	401	400	397	393
Interior	146	148	130	142	160	157	163
West	549	678	678	682	910	899	914
East of the Mississippi	481	500	508	495	521	524	515
West of the Mississippi	603	729	704	730	948	929	956
Total	**1083**	**1229**	**1212**	**1225**	**1469**	**1453**	**1471**
Net Imports							
Imports	25	33	33	33	46	46	46
Exports	43	42	42	42	26	27	26
Total	**-18**	**-9**	**-9**	**-9**	**20**	**19**	**20**
Total Supply[2]	**1065**	**1220**	**1203**	**1216**	**1489**	**1472**	**1490**
Consumption by Sector							
Residential and Commercial	4	5	5	5	5	5	5
Industrial[3]	62	66	66	66	65	65	65
Coke Plants	24	20	20	20	13	13	13
Electric Power[4]	1004	1130	1112	1126	1406	1390	1408
Total Sectoral Consumption	**1095**	**1220**	**1203**	**1217**	**1490**	**1473**	**1491**
Coal to Liquids							
Heat and Power (included in Industrial)	0	0	0	0	0	0	0
Liquids Production	0	0	0	0	0	0	0
Total Coal Use	**1095**	**1220**	**1203**	**1217**	**1490**	**1473**	**1491**
Discrepancy and Stock Change[5]	**-29**	**-0**	**-0**	**-0**	**-1**	**-1**	**-1**
Average Minemouth Price							
(2003 dollars per short ton)	17.93	17.31	17.54	17.28	17.87	18.55	17.74
(2003 dollars per million Btu)	0.86	0.85	0.86	0.85	0.89	0.92	0.88
Delivered Prices (2003 dollars per short ton)[6]							
Industrial	34.72	33.44	33.62	33.52	34.32	34.98	34.28
Coke Plants	50.63	50.07	50.11	50.07	46.24	46.27	46.25
Electric Power							
(2003 dollars per short ton)	25.85	25.00	25.40	25.18	25.58	26.46	26.05
(2003 dollars per million Btu)	1.28	1.26	1.26	1.27	1.29	1.32	1.31
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average	**26.90**	**25.87**	**26.27**	**26.05**	**26.15**	**27.02**	**26.59**
Exports[7]	39.80	39.41	39.40	39.34	36.24	36.20	36.20

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004); EIA, *Annual Coal Report 2003*, DOE/EIA-0584(2003) (Washington, DC, September 2004); and EIA, AEO2005 National Energy Modeling System run CAIR2005.D010505A.
Projections: EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C8. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Electric Power Sector[1]							
Net Summer Capacity							
Conventional Hydropower	77.93	78.18	78.18	78.18	78.18	78.18	78.18
Geothermal[2]	2.18	2.21	2.21	2.21	5.19	5.21	5.01
Municipal Solid Waste[3]	3.34	3.57	3.57	3.57	3.65	3.66	3.66
Wood and Other Biomass[4,5]	1.77	1.78	1.78	1.78	4.40	4.12	4.34
Solar Thermal	0.39	0.45	0.45	0.45	0.51	0.51	0.51
Solar Photovoltaic[5]	0.04	0.15	0.15	0.15	0.40	0.40	0.40
Wind	6.56	8.88	8.88	8.88	11.37	11.43	11.48
Total	**92.21**	**95.22**	**95.22**	**95.22**	**103.70**	**103.51**	**103.60**
Generation (billion kilowatthours)							
Conventional Hydropower	269.29	300.39	300.39	300.39	301.09	301.09	301.09
Geothermal[2]	13.15	12.33	12.33	12.33	37.69	37.86	36.16
Municipal Solid Waste[3]	20.28	25.58	25.58	25.58	26.37	26.45	26.45
Wood and Other Biomass[5]	9.40	31.97	32.66	31.77	51.61	52.77	49.88
Dedicated Plants	3.49	10.08	10.08	10.08	27.02	25.33	27.04
Cofiring	5.91	21.89	22.58	21.69	24.59	27.44	22.84
Solar Thermal	0.53	0.80	0.80	0.80	0.99	0.99	0.99
Solar Photovoltaic[6]	0.00	0.32	0.32	0.32	0.96	0.96	0.96
Wind	10.73	25.89	25.89	25.89	34.93	35.14	35.34
Total	**323.38**	**397.26**	**397.95**	**397.06**	**453.65**	**455.26**	**450.87**
End- Use Sector[7]							
Net Summer Capacity							
Conventional Hydropower[8]	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Biomass	4.08	5.13	5.13	5.13	6.74	6.74	6.74
Solar Photovoltaic[6]	0.06	0.39	0.39	0.39	1.88	1.89	1.85
Total	**5.43**	**6.81**	**6.81**	**6.81**	**9.93**	**9.93**	**9.89**
Generation (billion kilowatthours)							
Conventional Hydropower[8]	5.82	5.82	5.82	5.82	5.82	5.82	5.82
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	1.86	2.24	2.24	2.24	2.24	2.24	2.24
Biomass	27.59	33.73	33.73	33.73	43.14	43.11	43.13
Solar Photovoltaic[6]	0.12	0.83	0.83	0.83	3.91	3.92	3.85
Total	**35.39**	**42.61**	**42.61**	**42.61**	**55.11**	**55.09**	**55.03**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2002, EIA estimates that as much as 134 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2002, plus an additional 362 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Annual Energy Review 2003, Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2005. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.
Sources: 2003 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2003 generation: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Table C9. Emissions, Allowance Prices, and Emission Controls in the Electric Power Sector

Emission Levels, Prices, and Characteristics	2003	Projections					
		2010			2025		
		pCAIR	EPA Cap	EPA MACT	pCAIR	EPA Cap	EPA MACT
Emissions							
Nitrogen Oxides (million tons)	4.12	2.28	2.26	2.27	2.20	2.20	2.21
Sulfur Dioxide (million tons)	10.59	5.79	5.78	5.63	3.90	3.84	3.83
from Coal	10.15	5.41	5.40	5.25	3.52	3.46	3.45
from Oil/Other	0.44	0.38	0.38	0.38	0.38	0.38	0.38
Mercury (tons)	49.99	45.77	34.00	35.87	44.08	30.15	40.17
Carbon Dioxide (million metric tons)	2285.65	2605.61	2595.54	2600.02	3272.65	3255.72	3269.88
Allowance Prices							
Nitrogen Oxides (2003 dollars per ton)							
Regional/Seasonal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
East/Annual	0.00	2270.85	2233.42	2236.86	2789.44	2591.73	2576.35
West/Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfur Dioxide (2003 dollars per ton)							
East	488.26	772.67	739.60	793.09	1463.32	1226.27	1354.97
West	488.26	386.33	369.79	396.54	512.16	429.19	474.23
Mercury (thousand 2003 dollars per pound)	0.00	0.00	23.57	0.00	0.00	35.00	0.00
Carbon Dioxide (2003 dollars per million metric ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)							
Scrubber							
Planned	0.00	18.80	18.80	18.80	21.65	21.65	21.65
Unplanned	0.00	59.13	55.94	58.09	106.18	107.34	106.94
Total	0.00	77.93	74.74	76.89	127.83	128.99	128.59
Nitrogen Oxides Controls							
Combustion	0.00	26.70	27.47	28.98	34.01	34.41	34.61
SCR Post-combustion	0.00	107.29	108.45	109.06	133.42	134.51	135.18
SNCR Post-combustion	0.00	18.37	16.85	15.26	36.78	31.47	31.15
Coal Production by Sulfur Category (million tons)							
Low Sulfur (< .61 pounds per million Btu)	520.37	649.17	657.33	657.28	846.64	840.66	850.05
Medium Sulfur	398.10	381.55	378.11	377.40	410.95	409.69	408.20
High Sulfur (> 1.67 pounds per million Btu)	164.90	198.31	176.14	190.68	211.67	202.83	212.39
Interregional Sulfur Dioxide Allowances							
Target (million tons)	9.48	5.09	5.09	5.09	3.93	3.93	3.93
Cumulative Banked Allowances	7.40	11.80	10.97	10.76	3.03	2.79	2.94
Coal Characteristics							
SO_2 Content (pounds per million Btu)	1.84	1.85	1.82	1.82	1.76	1.75	1.75
Mercury Content (pounds per trillion Btu)	7.42	7.62	7.42	7.59	7.26	7.10	7.26
ACI Controls							
Spray Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Fabric Filter	0.00	0.00	0.56	70.64	0.00	0.56	70.87
ACI Removal (tons)	**0.00**	**0.00**	**7.21**	**8.81**	**0.00**	**10.46**	**6.46**
Allowance Revenues (billion 2003 dollars)							
Nitrogen Oxides	0.00	3.64	3.58	3.58	3.72	3.46	3.44
Sulfur Dioxide	1.85	3.36	3.20	3.45	4.92	4.41	4.47
Mercury	0.00	0.00	1.55	0.00	0.00	2.11	0.00
Carbon Dioxide	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**1.85**	**6.99**	**8.32**	**7.03**	**8.64**	**9.98**	**7.90**

Btu = British thermal unit.
ACI = Activated carbon injection.
SCR = Selective catalytic reduction.
SNCR = Selective non-catalytic reduction.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_CAP.D010405B, and CAIR2005_M29.D010505A.

Appendix D

pCAIR, MACT90, MACT90SL80, and MACT90NoACI Run Tables

Table D1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Production									
Crude Oil and Lease Condensate	12.03	12.75	12.75	12.77	12.77	10.01	10.01	10.06	10.11
Natural Gas Plant Liquids	2.34	2.67	2.67	2.63	2.67	2.77	2.78	2.78	2.86
Dry Natural Gas	19.58	21.02	21.01	20.61	20.99	22.10	22.15	22.19	22.91
Coal	22.66	24.92	24.82	20.10	18.72	29.56	29.51	26.86	25.56
Nuclear Power	7.97	8.49	8.49	8.49	8.49	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.91	6.90	6.87	7.49	7.31	8.41	8.35	9.04	8.61
Other[2]	0.93	0.96	0.97	0.94	0.93	0.82	0.83	0.83	0.83
Total	**71.44**	**77.71**	**77.57**	**73.03**	**71.89**	**82.33**	**82.28**	**80.43**	**79.55**
Imports									
Crude Oil[3]	21.08	24.66	24.67	24.70	24.88	35.24	35.27	35.11	35.22
Petroleum Products[4]	5.16	6.06	5.97	5.85	6.07	8.12	8.06	8.27	8.30
Natural Gas	4.02	5.75	5.78	6.85	7.19	9.99	10.00	10.25	10.25
Other Imports[5]	0.69	0.93	0.93	0.93	0.96	1.23	1.23	1.22	1.23
Total	**30.95**	**37.40**	**37.35**	**38.33**	**39.11**	**54.58**	**54.56**	**54.85**	**54.99**
Exports									
Petroleum[6]	2.13	2.15	2.14	2.13	2.16	2.32	2.32	2.33	2.33
Natural Gas	0.70	0.65	0.65	0.62	0.60	0.83	0.83	0.77	0.71
Coal	1.12	1.06	1.06	1.06	1.06	0.65	0.65	0.64	0.62
Total	**3.95**	**3.86**	**3.85**	**3.81**	**3.82**	**3.80**	**3.80**	**3.74**	**3.66**
Discrepancy[7]	**0.19**	**0.03**	**0.03**	**0.15**	**0.08**	**0.13**	**0.14**	**0.13**	**0.13**
Consumption									
Petroleum Products[8]	39.09	44.81	44.75	44.63	45.06	54.29	54.26	54.37	54.64
Natural Gas	22.54	26.19	26.21	26.92	27.65	31.44	31.50	31.85	32.63
Coal	22.71	24.77	24.67	19.79	18.48	30.14	30.09	27.44	26.15
Nuclear Power	7.97	8.49	8.49	8.49	8.49	8.67	8.67	8.67	8.67
Renewable Energy[1]	5.91	6.90	6.87	7.49	7.32	8.41	8.35	9.04	8.61
Other[9]	0.02	0.05	0.05	0.06	0.10	0.04	0.04	0.05	0.06
Total	**98.24**	**111.21**	**111.04**	**107.39**	**107.10**	**132.99**	**132.91**	**131.40**	**130.75**
Net Imports - Petroleum	**24.10**	**28.57**	**28.50**	**28.42**	**28.80**	**41.04**	**41.02**	**41.05**	**41.19**
Prices (2003 dollars per unit)									
World Oil Price (dollars per barrel)[10]	27.73	25.00	25.00	25.00	25.00	30.31	30.31	30.31	30.31
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.98	3.66	3.69	4.17	4.63	4.81	4.79	5.03	4.91
Coal Minemouth Price (dollars per ton)	17.93	17.31	17.93	64.61	48.83	17.87	18.88	30.15	29.55
Average Electricity Price (cents per kilowatthour)	7.4	6.8	6.8	8.0	8.2	7.4	7.4	7.7	7.9

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table C18 for selected nonmarketed residential and commercial renewable energy.
[2]Includes liquid hydrogen, methanol, supplemental natural gas, and some domestic inputs to refineries.
[3]Includes imports of crude oil for the Strategic Petroleum Reserve.
[4]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, and blending components.
[5]Includes coal, coal coke (net), and electricity (net).
[6]Includes crude oil and petroleum products.
[7]Balancing item. Includes unaccounted for supply, losses, gains, net storage withdrawals, heat loss when natural gas is converted to liquid fuel, and heat loss when coal is converted to liquid fuel.
[8]Includes natural gas plant liquids, crude oil consumed as a fuel, and nonpetroleum-based liquids for blending, such as ethanol.
[9]Includes net electricity imports, methanol, and liquid hydrogen.
[10]Average refiner acquisition cost for imported crude oil.
[11]Represents lower 48 onshore and offshore supplies.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 petroleum supply values: EIA, *Petroleum Supply Annual 2003,* DOE/EIA-0340(2003)/1 (Washington, DC, July 2004). Other 2003 values: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004) and EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Energy Consumption									
Residential									
Distillate Fuel	0.96	0.90	0.90	0.90	0.90	0.77	0.77	0.77	0.78
Kerosene	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Liquefied Petroleum Gas	0.54	0.57	0.57	0.57	0.57	0.67	0.67	0.67	0.67
Petroleum Subtotal	1.58	1.56	1.56	1.56	1.56	1.53	1.53	1.53	1.53
Natural Gas	5.25	5.68	5.68	5.56	5.47	6.16	6.16	6.12	6.15
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.40	0.40	0.40	0.40	0.39	0.38	0.38	0.38	0.38
Electricity	4.37	5.00	4.99	4.73	4.70	6.15	6.15	6.07	6.06
Delivered Energy	**11.61**	**12.65**	**12.64**	**12.27**	**12.13**	**14.23**	**14.23**	**14.11**	**14.12**
Electricity Related Losses	9.71	10.80	10.75	9.86	9.91	12.33	12.31	11.94	11.66
Total	**21.32**	**23.45**	**23.39**	**22.12**	**22.04**	**26.56**	**26.53**	**26.05**	**25.79**
Commercial									
Distillate Fuel	0.52	0.62	0.62	0.62	0.62	0.77	0.77	0.77	0.77
Residual Fuel	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08
Kerosene	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Liquefied Petroleum Gas	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11	0.11
Motor Gasoline[2]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.75	0.86	0.86	0.86	0.86	1.02	1.02	1.02	1.03
Natural Gas	3.22	3.48	3.48	3.40	3.35	4.16	4.17	4.14	4.19
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Electricity	4.13	4.99	4.98	4.75	4.72	7.10	7.09	7.00	6.94
Delivered Energy	**8.29**	**9.51**	**9.50**	**9.20**	**9.11**	**12.46**	**12.45**	**12.35**	**12.33**
Electricity Related Losses	9.18	10.77	10.73	9.90	9.95	14.22	14.19	13.75	13.36
Total	**17.47**	**20.28**	**20.23**	**19.10**	**19.06**	**26.68**	**26.64**	**26.10**	**25.69**
Industrial[4]									
Distillate Fuel	1.03	1.04	1.04	1.03	1.03	1.19	1.19	1.19	1.18
Liquefied Petroleum Gas	2.09	2.30	2.30	2.26	2.26	2.73	2.73	2.72	2.73
Petrochemical Feedstock	1.32	1.48	1.48	1.43	1.42	1.56	1.56	1.55	1.56
Residual Fuel	0.28	0.33	0.33	0.34	0.35	0.37	0.38	0.38	0.37
Motor Gasoline[2]	0.31	0.31	0.31	0.31	0.31	0.37	0.37	0.37	0.37
Other Petroleum[5]	4.30	4.69	4.69	4.71	4.69	5.24	5.23	5.23	5.22
Petroleum Subtotal	9.31	10.16	10.16	10.08	10.06	11.47	11.46	11.43	11.44
Natural Gas	7.19	8.09	8.09	8.11	7.99	9.30	9.33	9.60	9.77
Lease and Plant Fuel[6]	1.15	1.21	1.20	1.19	1.20	1.29	1.29	1.29	1.33
Natural Gas Subtotal	8.34	9.30	9.29	9.30	9.19	10.59	10.62	10.90	11.09
Metallurgical Coal	0.67	0.55	0.55	0.55	0.55	0.37	0.37	0.37	0.37
Steam Coal	1.39	1.42	1.42	1.24	1.28	1.41	1.41	1.25	1.28
Net Coal Coke Imports	0.05	0.05	0.05	0.03	0.03	0.05	0.04	0.03	0.03
Coal Subtotal	2.11	2.03	2.03	1.83	1.86	1.83	1.82	1.65	1.67
Renewable Energy[7]	1.79	2.07	2.06	2.05	2.04	2.49	2.49	2.49	2.49
Electricity	3.31	3.77	3.76	3.61	3.58	4.36	4.35	4.26	4.23
Delivered Energy	**24.86**	**27.32**	**27.30**	**26.86**	**26.74**	**30.74**	**30.76**	**30.72**	**30.93**
Electricity Related Losses	7.35	8.13	8.11	7.52	7.55	8.74	8.72	8.37	8.14
Total	**32.21**	**35.45**	**35.41**	**34.37**	**34.29**	**39.48**	**39.47**	**39.09**	**39.07**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections 2010 pCAIR	2010 MACT90	2010 MACT90, SL80	2010 MACT90, No ACI	2025 pCAIR	2025 MACT90	2025 MACT90, SL80	2025 MACT90, No ACI
Transportation									
Distillate Fuel[8]	5.54	6.94	6.93	6.82	6.74	9.04	9.04	8.98	9.00
Jet Fuel[9]	3.26	4.04	4.03	4.00	3.99	4.89	4.89	4.88	4.89
Motor Gasoline[2]	16.64	19.14	19.13	19.07	19.05	24.04	24.03	24.02	24.01
Residual Fuel	0.62	0.56	0.56	0.57	0.56	0.58	0.58	0.58	0.58
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.06	0.09	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.25	0.25	0.31	0.31	0.31	0.31
Petroleum Subtotal	26.31	30.99	30.97	30.76	30.65	38.95	38.94	38.86	38.88
Pipeline Fuel Natural Gas	0.65	0.70	0.70	0.70	0.71	0.84	0.84	0.84	0.85
Compressed Natural Gas	0.02	0.06	0.06	0.06	0.06	0.11	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.09	0.12	0.12	0.12	0.12
Delivered Energy	**27.07**	**31.84**	**31.82**	**31.61**	**31.52**	**40.02**	**40.01**	**39.93**	**39.97**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.19	0.24	0.24	0.24	0.23
Total	**27.24**	**32.03**	**32.02**	**31.79**	**31.70**	**40.26**	**40.25**	**40.17**	**40.20**
Delivered Energy Consumption for All Sectors									
Distillate Fuel	8.04	9.50	9.49	9.37	9.29	11.77	11.77	11.71	11.73
Kerosene	0.11	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13
Jet Fuel[9]	3.26	4.04	4.03	4.00	3.99	4.89	4.89	4.88	4.89
Liquefied Petroleum Gas	2.75	3.03	3.03	2.99	2.99	3.59	3.59	3.58	3.59
Motor Gasoline[2]	16.98	19.50	19.49	19.41	19.40	24.45	24.44	24.43	24.42
Petrochemical Feedstock	1.32	1.48	1.48	1.43	1.42	1.56	1.56	1.55	1.56
Residual Fuel	0.97	0.97	0.97	0.98	0.98	1.03	1.04	1.04	1.03
Other Petroleum[12]	4.52	4.93	4.93	4.94	4.93	5.53	5.52	5.53	5.52
Petroleum Subtotal	37.96	43.57	43.55	43.26	43.13	52.96	52.95	52.84	52.87
Natural Gas	15.68	17.32	17.30	17.13	16.86	19.73	19.77	19.97	20.21
Lease and Plant Fuel Plant[6]	1.15	1.21	1.20	1.19	1.20	1.29	1.29	1.29	1.33
Pipeline Natural Gas	0.65	0.70	0.70	0.70	0.71	0.84	0.84	0.84	0.85
Natural Gas Subtotal	17.48	19.22	19.21	19.02	18.78	21.86	21.90	22.11	22.38
Metallurgical Coal	0.67	0.55	0.55	0.55	0.55	0.37	0.37	0.37	0.37
Steam Coal	1.50	1.53	1.53	1.35	1.39	1.52	1.52	1.35	1.39
Net Coal Coke Imports	0.05	0.05	0.05	0.03	0.03	0.05	0.04	0.03	0.03
Coal Subtotal	2.22	2.14	2.13	1.94	1.97	1.93	1.93	1.75	1.78
Renewable Energy[13]	2.28	2.55	2.55	2.53	2.53	2.97	2.97	2.96	2.97
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.88	13.85	13.82	13.19	13.09	17.73	17.71	17.45	17.34
Delivered Energy	**71.82**	**81.33**	**81.26**	**79.93**	**79.50**	**97.45**	**97.45**	**97.11**	**97.35**
Electricity Related Losses	26.42	29.88	29.78	27.46	27.60	35.53	35.45	34.29	33.40
Total	**98.24**	**111.21**	**111.04**	**107.39**	**107.10**	**132.99**	**132.91**	**131.40**	**130.75**
Electric Power[14]									
Distillate Fuel	0.33	0.41	0.36	0.40	0.66	0.47	0.44	0.61	0.62
Residual Fuel	0.80	0.83	0.83	0.98	1.27	0.86	0.88	0.91	1.15
Petroleum Subtotal	1.13	1.24	1.20	1.37	1.93	1.33	1.32	1.52	1.77
Natural Gas	5.06	6.97	7.00	7.90	8.87	9.58	9.59	9.74	10.24
Steam Coal	20.49	22.64	22.54	17.86	16.51	28.20	28.16	25.68	24.37
Nuclear Power	7.97	8.49	8.49	8.49	8.49	8.67	8.67	8.67	8.67
Renewable Energy[15]	3.64	4.35	4.32	4.96	4.79	5.45	5.39	6.08	5.64
Electricity Imports	0.02	0.05	0.05	0.06	0.10	0.04	0.04	0.05	0.06
Total	**38.30**	**43.73**	**43.60**	**40.65**	**40.69**	**53.27**	**53.16**	**51.74**	**50.74**

Table D2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Total Energy Consumption									
Distillate Fuel	8.37	9.91	9.85	9.77	9.95	12.24	12.21	12.32	12.35
Kerosene	0.11	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13
Jet Fuel[9]	3.26	4.04	4.03	4.00	3.99	4.89	4.89	4.88	4.89
Liquefied Petroleum Gas	2.75	3.03	3.03	2.99	2.99	3.59	3.59	3.58	3.59
Motor Gasoline[2]	16.98	19.50	19.49	19.41	19.40	24.45	24.44	24.43	24.42
Petrochemical Feedstock	1.32	1.48	1.48	1.43	1.42	1.56	1.56	1.55	1.56
Residual Fuel	1.77	1.80	1.80	1.95	2.26	1.90	1.91	1.95	2.18
Other Petroleum[12]	4.52	4.93	4.93	4.94	4.93	5.53	5.52	5.53	5.52
Petroleum Subtotal	39.09	44.81	44.75	44.63	45.06	54.29	54.26	54.37	54.64
Natural Gas	20.74	24.28	24.31	25.03	25.73	29.31	29.36	29.72	30.45
Lease and Plant Fuel[6]	1.15	1.21	1.20	1.19	1.20	1.29	1.29	1.29	1.33
Pipeline Natural Gas	0.65	0.70	0.70	0.70	0.71	0.84	0.84	0.84	0.85
Natural Gas Subtotal	22.54	26.19	26.21	26.92	27.65	31.44	31.50	31.85	32.63
Metallurgical Coal	0.67	0.55	0.55	0.55	0.55	0.37	0.37	0.37	0.37
Steam Coal	21.99	24.17	24.07	19.21	17.90	29.72	29.68	27.04	25.76
Net Coal Coke Imports	0.05	0.05	0.05	0.03	0.03	0.05	0.04	0.03	0.03
Coal Subtotal	22.71	24.77	24.67	19.79	18.48	30.14	30.09	27.44	26.15
Nuclear Power	7.97	8.49	8.49	8.49	8.49	8.67	8.67	8.67	8.67
Renewable Energy[16]	5.91	6.90	6.87	7.49	7.32	8.41	8.35	9.04	8.61
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.02	0.05	0.05	0.06	0.10	0.04	0.04	0.05	0.06
Total	**98.24**	**111.21**	**111.04**	**107.39**	**107.10**	**132.99**	**132.91**	**131.40**	**130.75**
Energy Use and Related Statistics									
Delivered Energy Use	71.82	81.33	81.26	79.93	79.50	97.45	97.45	97.11	97.35
Total Energy Use	98.24	111.21	111.04	107.39	107.10	132.99	132.91	131.40	130.75
Population (millions)	291.39	310.12	310.12	310.12	310.12	350.64	350.64	350.64	350.64
Gross Domestic Product (billion 2000 dollars)	10381	13078	13073	12972	12951	20287	20287	20294	20308
Carbon Dioxide Emissions (million metric tons)	5788.7	6612.5	6597.6	6153.1	6103.2	8019.4	8014.3	7766.0	7707.3

[1]Includes wood used for residential heating. See Table C4 and/or Table C17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power. See Table C18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]Includes consumption of energy from hydroelectric, wood and wood waste, municipal solid waste, and other biomass.
[8]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur.
[9]Includes only kerosene type.
[10]Includes aviation gasoline and lubricants.
[11]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Consumption values of 0.00 are values that round to 0.00, because they are less than 0.005.
Sources: 2003 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 population and gross domestic product: Global Insight macroeconomic model CTL0804, modified by EIA. 2003 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2003,* DOE/EIA-0573(2003) (Washington, DC, December 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D3. Energy Prices by Sector and Source
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Residential	**15.81**	**14.51**	**14.61**	**16.07**	**16.56**	**16.24**	**16.26**	**16.72**	**16.78**
Primary Energy[1]	9.68	8.36	8.38	8.79	9.16	9.64	9.63	9.83	9.72
Petroleum Products[2]	11.27	10.40	10.41	10.40	10.42	11.93	11.93	11.96	11.95
Distillate Fuel	9.57	8.22	8.23	8.23	8.26	9.12	9.11	9.16	9.15
Liquefied Petroleum Gas	14.58	14.25	14.24	14.25	14.24	15.65	15.64	15.65	15.63
Natural Gas	9.22	7.82	7.84	8.34	8.82	9.08	9.07	9.32	9.17
Electricity	25.42	23.43	23.66	27.06	27.63	24.50	24.56	25.41	25.75
Commercial	**15.63**	**14.00**	**14.11**	**16.09**	**16.75**	**16.35**	**16.38**	**16.98**	**17.23**
Primary Energy[1]	7.92	6.82	6.83	7.23	7.57	7.83	7.82	8.02	7.90
Petroleum Products[2]	8.03	7.10	7.07	7.05	7.06	7.83	7.83	7.84	7.83
Distillate Fuel	7.03	6.25	6.22	6.19	6.21	7.06	7.06	7.07	7.06
Residual Fuel	4.96	4.26	4.26	4.28	4.31	5.06	5.06	5.06	5.09
Natural Gas	8.08	6.89	6.91	7.40	7.84	7.97	7.96	8.20	8.06
Electricity	23.24	20.39	20.60	24.22	25.12	22.68	22.76	23.73	24.36
Industrial[3]	**7.78**	**6.91**	**6.95**	**7.62**	**7.84**	**8.16**	**8.16**	**8.35**	**8.33**
Primary Energy	6.49	5.55	5.56	5.85	5.98	6.65	6.64	6.76	6.68
Petroleum Products[2]	8.29	7.23	7.22	7.20	7.20	8.37	8.37	8.36	8.36
Distillate Fuel	7.24	6.76	6.70	6.66	6.68	7.73	7.76	7.71	7.72
Liquefied Petroleum Gas	12.57	10.02	10.01	10.01	10.01	11.35	11.34	11.36	11.34
Residual Fuel	4.59	3.88	3.88	3.90	3.93	4.61	4.61	4.62	4.63
Natural Gas[4]	5.56	4.40	4.42	4.88	5.32	5.49	5.48	5.69	5.56
Metallurgical Coal	1.85	1.83	1.83	1.86	1.87	1.69	1.69	1.69	1.70
Steam Coal	1.55	1.55	1.57	2.92	2.31	1.59	1.63	1.72	1.69
Electricity	15.03	14.24	14.47	17.47	18.14	15.96	16.02	16.82	17.22
Transportation	**11.46**	**10.90**	**10.91**	**10.84**	**10.86**	**11.46**	**11.48**	**11.46**	**11.47**
Primary Energy	11.43	10.88	10.88	10.81	10.83	11.44	11.46	11.43	11.44
Petroleum Products[2]	11.43	10.88	10.89	10.81	10.83	11.44	11.46	11.44	11.45
Distillate Fuel[5]	10.92	10.73	10.63	10.57	10.57	10.84	10.87	10.82	10.85
Jet Fuel[6]	6.46	6.22	6.20	6.16	6.14	6.93	6.93	6.92	6.91
Motor Gasoline[7]	12.93	12.26	12.30	12.20	12.23	12.81	12.84	12.82	12.83
Residual Fuel	4.49	3.74	3.74	3.75	3.76	4.55	4.55	4.56	4.57
Liquefied Petroleum Gas[8]	16.65	15.24	15.23	15.21	15.21	16.25	16.22	16.25	16.21
Natural Gas[9]	9.04	8.58	8.59	9.01	9.44	9.71	9.69	9.89	9.77
Ethanol (E85)[10]	16.23	17.09	17.15	16.99	17.02	18.20	18.19	18.35	18.30
Electricity	20.61	19.23	19.42	22.54	23.18	20.15	20.22	21.02	21.33
Average End-Use Energy	**11.50**	**10.61**	**10.66**	**11.29**	**11.52**	**11.87**	**11.89**	**12.07**	**12.10**
Primary Energy	9.32	8.59	8.60	8.74	8.86	9.55	9.55	9.61	9.56
Electricity	21.74	19.81	20.03	23.38	24.10	21.64	21.71	22.61	23.08
Electric Power[11]									
Fossil Fuel Average	2.24	2.08	2.10	3.77	3.59	2.45	2.49	2.95	2.97
Petroleum Products	5.28	4.56	4.54	4.50	4.54	5.48	5.46	5.52	5.44
Distillate Fuel	6.48	5.32	5.34	5.31	5.29	6.33	6.36	6.30	6.28
Residual Fuel	4.79	4.19	4.19	4.18	4.16	5.02	5.01	5.00	4.99
Natural Gas	5.46	4.30	4.32	4.84	5.45	5.45	5.45	5.73	5.63
Steam Coal	1.28	1.26	1.28	3.23	2.48	1.29	1.34	1.75	1.68

Table D3. Energy Prices by Sector and Source (Continued)
(2003 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2003	Projections 2010 pCAIR	2010 MACT90	2010 MACT90, SL80	2010 MACT90, No ACI	2025 pCAIR	2025 MACT90	2025 MACT90, SL80	2025 MACT90, No ACI
Average Price to All Users[12]									
Petroleum Products[2]	10.51	9.87	9.88	9.80	9.75	10.67	10.69	10.65	10.63
Distillate Fuel	9.90	9.49	9.45	9.37	9.26	10.02	10.05	9.96	9.97
Jet Fuel	6.46	6.22	6.20	6.16	6.14	6.93	6.93	6.92	6.91
Liquefied Petroleum Gas	13.04	10.99	10.98	11.00	10.99	12.34	12.33	12.35	12.33
Motor Gasoline[7]	12.93	12.25	12.28	12.19	12.22	12.80	12.82	12.81	12.82
Residual Fuel	4.66	3.99	3.99	4.01	4.03	4.80	4.80	4.80	4.82
Natural Gas	6.86	5.54	5.55	5.99	6.44	6.60	6.59	6.82	6.67
Coal	1.30	1.28	1.30	3.21	2.47	1.30	1.36	1.75	1.68
Ethanol (E85)[10]	16.23	17.09	17.15	16.99	17.02	18.20	18.19	18.35	18.30
Electricity	21.74	19.81	20.03	23.38	24.10	21.64	21.71	22.61	23.08
Non-Renewable Energy Expenditures by Sector (billion 2003 dollars)									
Residential	177.17	177.89	178.79	190.77	194.36	224.98	225.10	229.69	230.60
Commercial	128.15	132.01	132.83	146.69	151.12	202.30	202.59	208.22	210.92
Industrial	147.11	140.82	141.63	153.86	157.53	185.62	185.89	190.68	191.53
Transportation	302.59	339.54	339.49	335.14	334.61	449.08	449.72	448.08	448.71
Total Non-Renewable Expenditures	755.02	790.26	792.74	826.46	837.62	1061.99	1063.30	1076.67	1081.76
Transportation Renewable Expenditures	0.02	0.03	0.03	0.03	0.03	0.08	0.08	0.08	0.08
Total Expenditures	**755.04**	**790.30**	**792.78**	**826.49**	**837.65**	**1062.06**	**1063.38**	**1076.75**	**1081.84**

[1]Weighted average price includes fuels below as well as coal.
[2]This quantity is the weighted average for all petroleum products, not just those listed below.
[3]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[8]Includes Federal and State taxes while excluding county and local taxes.
[9]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2003*, DOE/EIA-0487(2003) (Washington, DC, August 2004). 2003 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2003 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1998* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 natural gas delivered prices for the transportation sector are model results. 2003 coal prices based on EIA, *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004) and EIA, AEO2005 National Energy Modeling System run CAIR2005.D010505A. 2003 electricity prices: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Generation by Fuel Type									
Electric Power Sector[1]									
Power Only[2]									
Coal	1916	2139	2130	1693	1553	2795	2787	2572	2521
Petroleum	106	110	105	121	177	119	118	143	170
Natural Gas[3]	407	645	648	772	865	1055	1057	1086	1121
Nuclear Power	764	813	813	813	813	830	830	830	830
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources[4]	318	393	391	453	429	450	444	496	465
Distributed Generation (Natural Gas)	0	0	0	0	0	3	3	3	2
Total	**3501**	**4092**	**4079**	**3844**	**3827**	**5243**	**5230**	**5121**	**5100**
Combined Heat and Power[5]									
Coal	34	33	35	29	3	33	35	32	3
Petroleum	7	6	6	9	12	7	7	7	8
Natural Gas	149	188	190	213	213	182	182	186	190
Renewable Sources	6	4	4	4	4	4	4	4	4
Total	**197**	**231**	**234**	**255**	**232**	**225**	**228**	**228**	**205**
Total Net Generation	**3699**	**4323**	**4313**	**4098**	**4060**	**5468**	**5458**	**5350**	**5305**
Less Direct Use	50	66	67	67	67	65	66	65	66
Net Available to the Grid	**3649**	**4257**	**4246**	**4032**	**3993**	**5403**	**5392**	**5284**	**5239**
Commercial and Industrial Generation[6]									
Coal	21	21	21	21	21	21	21	21	21
Petroleum	6	9	9	9	9	13	13	13	14
Natural Gas	76	100	101	121	120	178	184	228	252
Other Gaseous Fuels[7]	6	4	4	4	4	5	5	6	6
Renewable Sources[4]	35	43	43	42	42	55	55	55	56
Other[8]	10	10	10	10	10	10	10	10	10
Total	**153**	**187**	**188**	**207**	**206**	**282**	**287**	**333**	**358**
Less Direct Use	126	139	139	148	147	187	189	211	225
Total Sales to the Grid	**28**	**48**	**49**	**59**	**58**	**96**	**98**	**122**	**133**
Total Electricity Generation	**3852**	**4510**	**4500**	**4305**	**4266**	**5750**	**5745**	**5683**	**5664**
Total Net Generation to the Grid	**3677**	**4305**	**4295**	**4091**	**4052**	**5498**	**5491**	**5406**	**5373**
Net Imports	**5**	**14**	**14**	**19**	**30**	**12**	**12**	**14**	**16**
Electricity Sales by Sector									
Residential	1280	1466	1462	1387	1377	1804	1802	1780	1775
Commercial	1210	1462	1459	1394	1383	2080	2077	2051	2033
Industrial	969	1104	1102	1057	1050	1278	1276	1248	1239
Transportation	23	26	26	26	26	35	35	35	35
Total	**3481**	**4059**	**4050**	**3864**	**3836**	**5197**	**5190**	**5114**	**5083**
Direct Use	175	204	206	214	214	252	255	277	291
Total Electricity Use	**3657**	**4264**	**4255**	**4079**	**4050**	**5449**	**5444**	**5390**	**5374**
End-Use Prices[9] (2003 cents per kilowatthour)									
Residential	8.7	8.0	8.1	9.2	9.4	8.4	8.4	8.7	8.8
Commercial	7.9	7.0	7.0	8.3	8.6	7.7	7.8	8.1	8.3
Industrial	5.1	4.9	4.9	6.0	6.2	5.4	5.5	5.7	5.9
Transportation	7.0	6.6	6.6	7.7	7.9	6.9	6.9	7.2	7.3
All Sectors Average	**7.4**	**6.8**	**6.8**	**8.0**	**8.2**	**7.4**	**7.4**	**7.7**	**7.9**
Prices by Service Category[9] (2003 cents per kilowatthour)									
Generation	4.8	4.2	4.3	5.4	5.6	5.0	5.0	5.3	5.5
Transmission	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Distribution	2.1	2.0	2.0	2.0	2.0	1.8	1.8	1.8	1.8

Table D4. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Electric Power Sector Emissions[1]									
Sulfur Dioxide (million tons)	10.59	5.79	5.57	5.50	2.28	3.90	3.82	3.88	2.71
Nitrogen Oxide (million tons)	4.12	2.28	2.26	2.13	1.32	2.20	2.20	2.14	1.57
Mercury (tons)	49.99	45.77	8.82	7.09	6.72	44.08	9.91	9.82	8.88

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[5]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Prices represent average revenue per kilowatthour.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.

Sources: 2003 power only and combined heat and power generation, sales to utilities, net imports, residential, industrial, and total electricity sales, and emissions: Energy Information Administration (EIA), *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004), and supporting databases. 2003 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2003 prices: EIA, National Energy Modeling System run CAIR2005.D010505A. **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Electric Power Sector[2]									
Power Only[3]									
Coal Steam	305.2	303.2	302.1	300.1	301.3	386.8	384.1	359.9	383.0
Other Fossil Steam[4]	128.6	119.4	119.4	119.4	119.4	98.1	98.7	104.1	107.8
Combined Cycle	106.9	136.1	135.9	136.9	136.1	196.5	197.0	208.4	192.4
Combustion Turbine/Diesel	124.8	132.5	132.5	127.3	127.5	180.3	180.5	169.9	153.3
Nuclear Power[5]	99.2	100.6	100.6	100.6	100.6	102.7	102.7	102.7	102.7
Pumped Storage	20.8	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	92.0	95.0	95.0	95.0	97.3	103.5	103.2	106.8	107.0
Distributed Generation[7]	0.0	0.4	0.4	0.1	0.2	6.8	6.6	6.0	4.6
Total	**877.5**	**908.0**	**906.7**	**900.3**	**903.2**	**1095.5**	**1093.7**	**1078.6**	**1071.7**
Combined Heat and Power[8]									
Coal Steam	5.1	5.1	5.1	5.1	5.1	4.8	4.6	4.5	5.1
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	31.3	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5
Combustion Turbine/Diesel	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**42.8**	**45.1**	**45.1**	**45.0**	**45.0**	**44.8**	**44.6**	**44.4**	**45.0**
Cumulative Planned Additions[9]									
Coal Steam	0.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3
Combustion Turbine/Diesel	0.0	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	2.7	2.7	2.7	2.7	3.0	3.0	3.0	3.0
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**36.7**	**36.7**	**36.7**	**36.7**	**37.0**	**37.0**	**37.0**	**37.0**
Cumulative Unplanned Additions[9]									
Coal Steam	0.0	0.0	0.0	0.0	0.0	84.3	83.4	77.5	122.0
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	3.2	3.0	4.1	3.3	63.7	64.3	76.7	59.5
Combustion Turbine/Diesel	0.0	5.7	5.7	0.5	0.8	60.0	60.6	50.7	29.9
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	2.4	8.3	8.0	11.6	11.8
Distributed Generation[7]	0.0	0.4	0.4	0.1	0.2	6.8	6.6	6.0	4.6
Total	**0.0**	**9.4**	**9.2**	**4.8**	**6.7**	**223.1**	**222.9**	**222.5**	**227.9**
Cumulative Electric Power Sector Additions	**0.0**	**46.1**	**45.9**	**41.5**	**43.3**	**260.0**	**259.9**	**259.5**	**264.9**
Cumulative Retirements[10]									
Coal Steam	0.0	3.7	4.9	6.9	5.7	4.8	6.8	25.2	45.9
Other Fossil Steam[4]	0.0	9.3	9.3	9.3	9.3	30.5	29.9	24.5	20.8
Combined Cycle	0.0	0.1	0.1	0.1	0.1	0.2	0.2	1.3	0.1
Combustion Turbine/Diesel	0.0	1.9	1.9	1.9	1.9	8.4	8.8	9.5	5.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**15.1**	**16.2**	**18.3**	**17.1**	**44.0**	**45.8**	**60.6**	**72.1**
Total Electric Power Sector Capacity	**920.3**	**953.1**	**951.8**	**945.3**	**948.2**	**1140.2**	**1138.3**	**1123.1**	**1116.8**

Table D5. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
End-Use Sector[11]									
Coal	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Petroleum	0.7	1.5	1.5	1.5	1.6	1.8	1.7	1.8	1.9
Natural Gas	14.4	17.4	17.5	20.1	20.0	27.9	28.6	34.7	38.0
Other Gaseous Fuels	1.8	1.5	1.5	1.5	1.5	1.7	1.7	1.7	1.7
Renewable Sources[6]	5.4	6.8	6.8	6.7	6.7	9.9	9.9	10.1	10.6
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.1**	**32.1**	**32.2**	**34.8**	**34.7**	**46.1**	**46.8**	**53.2**	**57.0**
Cumulative Capacity Additions[9]	**0.0**	**5.0**	**5.1**	**7.7**	**7.6**	**19.0**	**19.7**	**26.1**	**29.9**

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.9 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak-load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2003.
[10]Cumulative total retirements after December 31, 2003.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model estimates and may differ slightly from official EIA data reports.
Sources: 2003 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D6. Natural Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Production									
Dry Gas Production[1]	19.07	20.46	20.46	20.06	20.44	21.52	21.56	21.60	22.31
Supplemental Natural Gas[2]	0.06	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Net Imports	**3.24**	**4.97**	**5.00**	**6.09**	**6.44**	**8.95**	**8.95**	**9.26**	**9.32**
Canada	3.13	2.59	2.60	2.63	2.85	2.50	2.49	2.72	2.65
Mexico	-0.33	-0.14	-0.13	-0.10	-0.08	-0.25	-0.25	-0.13	-0.01
Liquefied Natural Gas[3]	0.44	2.52	2.54	3.56	3.67	6.70	6.71	6.67	6.68
Total Supply	**22.37**	**25.51**	**25.54**	**26.23**	**26.95**	**30.54**	**30.59**	**30.94**	**31.70**
Consumption by Sector									
Residential	5.10	5.52	5.52	5.41	5.32	5.99	5.99	5.95	5.97
Commercial	3.13	3.38	3.38	3.30	3.25	4.05	4.05	4.03	4.07
Industrial[4]	6.99	7.87	7.86	7.88	7.77	9.04	9.07	9.33	9.49
Electric Power[5]	4.96	6.83	6.87	7.75	8.70	9.39	9.40	9.55	10.04
Transportation[5]	0.02	0.06	0.06	0.06	0.06	0.11	0.11	0.11	0.11
Pipeline Fuel	0.64	0.68	0.68	0.68	0.70	0.82	0.82	0.81	0.83
Lease and Plant Fuel[7]	1.12	1.17	1.17	1.16	1.17	1.26	1.26	1.26	1.29
Total	**21.95**	**25.51**	**25.54**	**26.23**	**26.95**	**30.64**	**30.70**	**31.04**	**31.80**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[8]	**0.42**	**-0.00**	**-0.00**	**-0.01**	**0.00**	**-0.11**	**-0.11**	**-0.10**	**-0.10**
Natural Gas Prices (2003 dollars per thousand cubic feet)									
Average Lower 48 Wellhead Price[9]	**4.98**	**3.66**	**3.69**	**4.17**	**4.63**	**4.81**	**4.79**	**5.03**	**4.91**
Delivered Prices									
Residential	9.49	8.04	8.06	8.59	9.08	9.35	9.33	9.59	9.44
Commercial	8.31	7.09	7.11	7.61	8.07	8.21	8.19	8.44	8.29
Industrial[4]	5.72	4.52	4.55	5.02	5.47	5.65	5.64	5.86	5.72
Electric Power[5]	5.57	4.38	4.40	4.94	5.56	5.56	5.56	5.84	5.74
Transportation[10]	9.31	8.82	8.84	9.27	9.71	9.99	9.97	10.17	10.05
Average[11]	**7.04**	**5.69**	**5.70**	**6.15**	**6.62**	**6.78**	**6.77**	**7.00**	**6.85**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2000 and 2001 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes.
[11]Weighted average prices and margins. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
Btu = British thermal unit.
N/A = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 and 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). Other 2003 consumption based on: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). 2003 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 electric power sector prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004. 2003 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2002*, DOE/EIA-0131(2002) (Washington, DC, January 2004) and the *Natural Gas Monthly*, DOE/EIA-0130(2004/07) (Washington, DC, July 2004). 2003 transportation sector delivered prices are model results. **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D7. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2003	Projections							
		2010				2025			
		pCAIR	MACT90	MACT90, SL80	MACT90, No ACI	pCAIR	MACT90	MACT90, SL80	MACT90, No ACI
Production[1]									
Appalachia	388	403	405	535	504	400	411	590	545
Interior	146	148	165	137	138	160	173	194	208
West	549	678	644	174	142	910	874	390	366
East of the Mississippi	481	500	519	667	637	521	542	775	745
West of the Mississippi	603	729	695	180	147	948	916	399	375
Total	**1083**	**1229**	**1214**	**847**	**784**	**1469**	**1458**	**1174**	**1120**
Net Imports									
Imports	25	33	33	33	33	46	46	46	46
Exports	43	42	42	42	42	26	26	26	25
Total	**-18**	**-9**	**-9**	**-9**	**-9**	**20**	**20**	**20**	**21**
Total Supply[2]	**1065**	**1220**	**1205**	**838**	**775**	**1489**	**1478**	**1194**	**1140**
Consumption by Sector									
Residential and Commercial	4	5	5	5	5	5	5	5	5
Industrial[3]	62	66	66	58	60	65	65	58	60
Coke Plants	24	20	20	20	20	13	13	13	13
Electric Power[4]	1004	1130	1115	750	688	1406	1395	1119	1064
Total Sectoral Consumption	**1095**	**1220**	**1206**	**834**	**773**	**1490**	**1479**	**1195**	**1142**
Coal to Liquids									
Heat and Power (included in Industrial)	0	0	0	0	0	0	0	0	0
Liquids Production	0	0	0	0	0	0	0	0	0
Total Coal Use	1095	1220	1206	834	773	1490	1479	1195	1142
Discrepancy and Stock Change[5]	**-29**	**-0**	**-0**	**4**	**2**	**-1**	**-1**	**-1**	**-2**
Average Minemouth Price									
(2003 dollars per short ton)	17.93	17.31	17.93	64.61	48.83	17.87	18.88	30.15	29.55
(2003 dollars per million Btu)	0.86	0.85	0.88	2.72	2.04	0.89	0.93	1.32	1.29
Delivered Prices (2003 dollars per short ton)[6]									
Industrial	34.72	33.44	33.94	62.13	49.17	34.32	35.14	36.78	35.90
Coke Plants	50.63	50.07	50.11	50.97	51.18	46.24	46.24	46.45	46.66
Electric Power									
(2003 dollars per short ton)	25.85	25.00	25.71	76.73	59.36	25.58	26.84	39.91	38.23
(2003 dollars per million Btu)	1.28	1.26	1.28	3.23	2.48	1.29	1.34	1.75	1.68
Coal to Liquids	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average	**26.90**	**25.87**	**26.57**	**75.08**	**58.35**	**26.15**	**27.39**	**39.83**	**38.20**
Exports[7]	39.80	39.41	39.56	52.99	47.11	36.24	36.44	37.51	37.14

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: 2003 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2003*, DOE/EIA-0121(2003/4Q) (Washington, DC, March 2004); EIA, *Annual Coal Report 2003*, DOE/EIA-0584(2003) (Washington, DC, September 2004); and EIA, AEO2005 National Energy Modeling System run CAIR2005.D010505A. **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D8. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2003	Projections 2010 pCAIR	2010 MACT90	2010 MACT90, SL80	2010 MACT90, No ACI	2025 pCAIR	2025 MACT90	2025 MACT90, SL80	2025 MACT90, No ACI
Electric Power Sector[1]									
Net Summer Capacity									
Conventional Hydropower	77.93	78.18	78.18	78.18	78.18	78.18	78.18	78.18	78.18
Geothermal[2]	2.18	2.21	2.21	2.21	2.58	5.19	5.15	5.76	5.48
Municipal Solid Waste[3]	3.34	3.57	3.57	3.56	3.70	3.65	3.66	3.83	3.86
Wood and Other Biomass[4,5]	1.77	1.78	1.78	1.78	1.87	4.40	4.48	4.75	5.03
Solar Thermal	0.39	0.45	0.45	0.45	0.45	0.51	0.51	0.51	0.51
Solar Photovoltaic[5]	0.04	0.15	0.15	0.15	0.15	0.40	0.40	0.40	0.40
Wind	6.56	8.88	8.88	8.88	10.60	11.37	11.10	13.64	13.82
Total	**92.21**	**95.22**	**95.22**	**95.21**	**97.52**	**103.70**	**103.48**	**107.08**	**107.29**
Generation (billion kilowatthours)									
Conventional Hydropower	269.29	300.39	300.39	300.33	300.32	301.09	301.09	301.05	301.05
Geothermal[2]	13.15	12.33	12.33	12.32	15.42	37.69	37.29	42.64	40.33
Municipal Solid Waste[3]	20.28	25.58	25.58	25.51	26.59	26.37	26.45	27.77	27.97
Wood and Other Biomass[5]	9.40	31.97	29.06	91.94	57.50	51.61	47.40	83.05	54.28
Dedicated Plants	3.49	10.08	10.08	10.08	10.46	27.02	27.44	29.12	32.73
Cofiring	5.91	21.89	18.98	81.86	47.04	24.59	19.96	53.94	21.55
Solar Thermal	0.53	0.80	0.80	0.80	0.80	0.99	0.99	0.99	0.99
Solar Photovoltaic[6]	0.00	0.32	0.32	0.32	0.32	0.96	0.96	0.96	0.96
Wind	10.73	25.89	25.89	25.89	31.70	34.93	33.90	43.21	43.44
Total	**323.38**	**397.26**	**394.35**	**457.10**	**432.64**	**453.65**	**448.09**	**499.69**	**469.03**
End- Use Sector[7]									
Net Summer Capacity									
Conventional Hydropower[8]	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26
Biomass	4.08	5.13	5.13	5.05	5.03	6.74	6.74	6.72	6.73
Solar Photovoltaic[6]	0.06	0.39	0.39	0.40	0.40	1.88	1.87	2.09	2.56
Total	**5.43**	**6.81**	**6.81**	**6.74**	**6.72**	**9.93**	**9.90**	**10.11**	**10.58**
Generation (billion kilowatthours)									
Conventional Hydropower[8]	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82	5.82
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Solid Waste	1.86	2.24	2.24	2.24	2.24	2.24	2.24	2.24	2.24
Biomass	27.59	33.73	33.71	33.24	33.13	43.14	43.13	43.01	43.04
Solar Photovoltaic[6]	0.12	0.83	0.83	0.86	0.85	3.91	3.87	4.34	5.27
Total	**35.39**	**42.61**	**42.59**	**42.15**	**42.04**	**55.11**	**55.05**	**55.41**	**56.36**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2002, EIA estimates that as much as 134 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2002, plus an additional 362 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Annual Energy Review 2003, Table 10.6 (annual PV shipments, 1989-2002). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2005. Net summer capacity is used to be consistent with electric utility capacity estimates. Additional retirements are determined on the basis of the size and age of the units.

Sources: 2003 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2003 generation: EIA, *Annual Energy Review 2003*, DOE/EIA-0384(2003) (Washington, DC, September 2004). **Projections:** EIA, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.

Table D9. Emissions, Allowance Prices, and Emission Controls in the Electric Power Sector

Emission Levels, Prices, and Characteristics	2003	Projections 2010 pCAIR	2010 MACT90	2010 MACT90, SL80	2010 MACT90, No ACI	2025 pCAIR	2025 MACT90	2025 MACT90, SL80	2025 MACT90, No ACI
Emissions									
Nitrogen Oxides (million tons)	4.12	2.28	2.26	2.13	1.32	2.20	2.20	2.14	1.57
Sulfur Dioxide (million tons)	10.59	5.79	5.57	5.50	2.28	3.90	3.82	3.88	2.71
from Coal	10.15	5.41	5.19	5.04	1.67	3.52	3.43	3.48	2.18
from Oil/Other	0.44	0.38	0.38	0.46	0.61	0.38	0.38	0.40	0.53
Mercury (tons)	49.99	45.77	8.82	7.09	6.72	44.08	9.91	9.82	8.88
Carbon Dioxide (million metric tons)	2285.65	2605.61	2592.66	2192.15	2159.40	3272.65	3266.56	3029.94	2953.06
Allowance Prices									
Nitrogen Oxides (2003 dollars per ton)									
Regional/Seasonal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
East/Annual	0.00	2270.85	2140.43	1943.85	0.00	2789.44	2270.96	118.91	0.00
West/Annual	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sulfur Dioxide (2003 dollars per ton)									
East	488.26	772.67	813.55	645.53	0.00	1463.32	1105.37	1282.17	0.02
West	488.26	386.33	406.77	322.76	0.00	512.16	386.87	448.75	0.00
Mercury (thousand 2003 dollars per pound)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide (2003 dollars per million metric ton)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)									
Scrubber									
Planned	0.00	18.80	18.80	18.80	18.80	21.65	21.65	21.65	21.65
Unplanned	0.00	59.13	62.92	67.90	173.30	106.18	111.37	135.37	180.73
Total	0.00	77.93	81.72	86.70	192.11	127.83	133.02	157.02	202.38
Nitrogen Oxides Controls									
Combustion	0.00	26.70	26.91	21.72	17.86	34.01	33.94	27.96	19.92
SCR Post-combustion	0.00	107.29	112.37	82.08	176.17	133.42	137.71	135.22	183.81
SNCR Post-combustion	0.00	18.37	13.65	16.00	11.53	36.78	31.54	22.87	11.53
Coal Production by Sulfur Category (million tons)									
Low Sulfur (< .61 pounds per million Btu)	520.37	649.17	623.62	244.60	200.25	846.64	818.56	438.41	393.18
Medium Sulfur	398.10	381.55	381.00	418.47	399.57	410.95	414.07	464.82	426.33
High Sulfur (> 1.67 pounds per million Btu)	164.90	198.31	209.74	184.16	184.09	211.67	225.51	270.74	300.32
Interregional Sulfur Dioxide Allowances									
Target (million tons)	9.48	5.09	5.09	5.09	5.09	3.93	3.93	3.93	3.93
Cumulative Banked Allowances	7.40	11.80	10.11	10.76	0.00	3.03	2.72	3.38	0.00
Coal Characteristics									
SO_2 Content (pounds per million Btu)	1.84	1.85	1.92	2.44	2.54	1.76	1.82	2.37	2.53
Mercury Content (pounds per trillion Btu)	7.42	7.62	7.64	7.71	7.86	7.26	7.31	7.70	7.81
ACI Controls									
Spray Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Supplemental Fabric Filter	0.00	0.00	183.51	107.63	0.00	0.00	195.09	131.01	0.00
ACI Removal (tons)	**0.00**	**0.00**	**33.39**	**14.66**	**0.00**	**0.00**	**31.96**	**12.83**	**0.00**
Allowance Revenues (billion 2003 dollars)									
Nitrogen Oxides	0.00	3.64	3.43	3.11	0.00	3.72	3.03	0.16	0.00
Sulfur Dioxide	1.85	3.36	2.82	3.56	0.00	4.92	3.99	5.04	0.00
Mercury	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**1.85**	**6.99**	**6.25**	**6.68**	**0.00**	**8.64**	**7.02**	**5.20**	**0.00**

Btu = British thermal unit.
ACI = Activated carbon injection.
SCR = Selective catalytic reduction.
SNCR = Selective non-catalytic reduction.
Note: Totals may not equal sum of components due to independent rounding. Data for 2003 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2005 National Energy Modeling System runs CAIR2005.D010505A, CAIR2005_M90.D010405A, CAIR2005_M90SL.D010505A, and CAIR2005_M90NA.D010505A.