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Analysis of S. 485, the Clear Skies Act of 2003, and S. 843, the Clean Air Planning Act of 2003

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Background

On July 30, 2003, Senator James M. Inhofe requested "the Energy Information Administration to undertake analyses of S.843, The Clean Air Planning Act of 2003, introduced by Senator Thomas Carper, and S.485, Clear Skies Act of 2003." Senator Inhofe also asked the Energy Information Administration (EIA) to analyze S. 485 without the mercury provisions and S. 843 without the mercury and carbon dioxide provisions. This service report responds to both requests.

The emissions caps and implementation timetables for S. 485 (Clear Skies) and S. 843 (Carper) are summarized in Table H1. Both bills implement emissions caps on power sector emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2) and mercury (Hg). For NO_x, the final emissions caps are the same for both bills, but the Carper bill calls for greater reductions earlier than the Clear Skies bill. For SO_2 and Hg, the Carper bill calls for both earlier and more stringent reductions. For Hg, both bills use a cap-and-trade system, although the Carper bill requires a minimum level of removal from all plants. The Clear Skies bill also contains a "safety valve" feature that caps the price that power companies would have to pay for Hg, SO_2, and NO_x allowances – should one or more of these "safety valves" be triggered, the corresponding cap on emissions would be effectively relaxed. The Carper bill also requires power sector reductions in carbon dioxide (CO_2) emissions. Power companies can meet their CO_2 targets by directly

Table H1. Emission Targets and Implementation Timetables in the Clear Skies and Carper Bills

Emission	S. 485, Clear Skies Targets	S. 843, Carper Targets
Nitrogen Oxides (NO_x)	2.1 million tons in 2008 1.7 million tons in 2018[1]	1.87 million tons in 2009 1.7 million tons in 2013
Sulfur Dioxide (SO_2)	4.5 million tons in 2010 3.0 million tons in 2018	4.5 million tons in 2009 3.5 million tons in 2013 2.25 million tons in 2016
Mercury (Hg)	26 tons in 2010 15 tons in 2018	24 tons in 2009 10 tons in 2013[2]
Carbon Dioxide (CO_2)	No cap	636 million metric tons carbon equivalent in 2009 612 million metric tons carbon equivalent in 2013[3]

1) Limit on NO_x emissions is split between 2 regions – 0.538 million tons in the West and 1.562 million tons in the East in 2008 with a further reduction to 1.138 million tons in the East in 2018.
2) Minimum facility-specific reductions are also required. Between 2009 and 2012 the minimum reduction is 50 percent, while after 2012 it is 70 percent.
3) 2009-2012 limits are based on EIA projected emissions for 2006; the limit for 2013 and subsequent years is based on actual 2001 emissions.

reducing emissions within the sector or by purchasing approved greenhouse gas (GHG) reductions from international trading programs or domestic projects outside the power sector. An independent review board is set up to establish the rules governing use of international or domestic emission offsets.

Highlights of the S.485 (Clear Skies Bill) Analysis

- Power generators are expected to rely primarily on the addition of emissions control equipment to comply with the emissions caps.
- Fuel switching from coal to natural gas is projected to play a secondary role. Coal generation in 2020 is projected to be 6 percent below the Reference case level while natural gas generation is 9 percent higher. Despite the reduction in coal generation, coal generation is expected to grow 24 percent between 2001 and 2020.
- The Clear Skies cap on mercury affects the regional composition of coal use due to the higher cost of removing mercury from subbituminous coals. While use of western coal falls slightly below Reference case levels in the Clear Skies case, it increases above Reference case levels in a sensitivity case that assumes no Clear Skies mercury provisions and no imposition of Maximum Achievable Control Technology (MACT) standards under existing law requiring all plants to achieve specified mercury removal levels.
- The safety valve for the mercury allowance price is triggered, so mercury emissions remain above the targets in Table H1. Mercury emissions in 2010 are expected to be 31 tons, compared to 53 tons in the Reference case and 45 tons in a sensitivity case where only the NO_x and SO_2 caps are imposed. Mercury emissions are projected to reach 29 tons in 2025.
- Although the Clear Skies bill also establishes safety valves for the SO_2 and NO_x allowance prices, this analysis projects that neither will be triggered.
- To reduce SO_2 emissions, 85 gigawatts (GW) of capacity are expected to add scrubbers by 2020. Selective catalytic reduction (SCR) equipment is projected to be the key NO_x emission reduction technology, with 171 GW added by 2020. In addition, mercury compliance requires 6 GW of supplemental fabric filters with activated carbon injection by 2020.
- In 2020, under Clear Skies, NO_x allowance prices in the East are projected to reach $2,354 per ton (all values given in 2001 dollars), while NO_x allowance prices in the West are $1,722 per ton. In 2020, SO_2 allowance prices are projected to be $966 per ton, while mercury allowance prices are limited to $35,000 per pound by the safety valve. In a sensitivity case without the mercury safety valve, mercury allowance prices in 2020 are projected to be $68,000 per pound.
- Resource costs, the amount that power companies spend on fuel, capital, and operations and maintenance, are projected to be higher under Clear Skies than in the Reference case. Over the 2005 to 2025 time period, the discounted change in resource costs and mercury safety valve payments is projected to be $24.4 billion more than that of the Reference case. Of this amount, approximately $3.5 billion is attributable to safety valve payments. Discounted resource costs over the 2005 to 2025 period increase by 1.7 percent relative to the Reference case.

- Electricity prices are also projected to be higher under Clear Skies. In 2020, the national electricity price is projected to be 2.5 percent above that in the Reference case, but still below the real price in 2001.

Highlights of the S. 843 (Carper Bill) Analysis

- The role of fuel switching – from coal to natural gas and renewables – is projected to be much more important in the Carper bill than in the Clear Skies bill. This reflects the more restrictive emissions limits for SOx, NOx, and Hg, and the additional limits on CO_2 emissions under the Carper bill. However, the results are very sensitive to the availability and cost of greenhouse gas offsets from outside the U.S. power sector. Three alternative cases with different assumptions about the availability of greenhouse gas offsets were prepared.
- Coal generation in 2020 is projected to range between 12 percent and 32 percent below the Reference case in the three Carper cases with alternative assumptions about the availability of greenhouse gas offsets, while gas generation in 2020 is projected to range between 18 percent and 24 percent above the Reference case level in the three cases.
- The Carper bill caps on mercury and CO_2 emissions affect the regional composition of coal use due to the relatively high carbon content of coal and the higher cost of removing mercury from subbituminous coals. Total coal production in the Carper cases is projected to be between 12 percent and 30 percent below the Reference case level in 2020, depending on the availability and cost of greenhouse gas offsets from outside the U.S. power sector.. However, the impact on western coal use is projected to be larger, because it is generally more difficult to remove mercury from subbituminous coals. In 2020, western coal production is projected to be between 19 percent and 38 percent below the Reference case level.
- Renewable fuels are also expected to play a large role in the three Carper cases. In 2020, renewable generation is projected to be between 6 percent and 89 percent above the Reference case level in the three cases. The renewables expected to see the largest growth in these cases are biomass and wind.
- Under the Carper bill, NO_x, SO_2 and mercury allowance prices are very sensitive to the availability and cost of CO_2 offsets. CO_2 allowance prices in 2020 are projected to range from $20 per metric ton carbon equivalent to $127 per metric ton carbon equivalent. In general, NO_x, SO_2 and mercury allowance prices tend to be lower when CO_2 allowance prices are higher because of reduced coal use,. In 2020, NO_x allowance prices are projected to range from $0 to $1,914 per ton (all values given in 2001 dollars), while SO_2 allowance prices range from $1,126 per ton to $1,483 per ton and mercury allowance prices range from $12,855 per pound to $23,501 per pound. The relatively low mercury allowances prices are due to reduced coal use and the requirement in the Carper bill that all coal plants remove at least 70 percent of the mercury in the coal they use after 2012.
- The change in discounted resource and offset purchase costs over the 2005 to 2025 time period in the three cases ranges from $64.5 billion to $156.1 billion ($ 2001).

- Electricity prices in 2020 in the three Carper cases are projected to range between 3.9 percent and 6.4 percent above the Reference case.
- In a sensitivity case where only the NO_x, SO_2, and Hg caps in the Carper bill are imposed (Carper 3-P sensitivity case), power generators are projected to rely primarily on the addition of emissions control equipment rather than fuel switching. Coal generation in 2020 in this case is projected to be 5 percent below the Reference case level while natural gas generation is 6 percent higher. Although the emissions targets in this sensitivity are generally more stringent than those in the Clear Skies bill, there is less fuel switching because the allowance allocation scheme in the Carper bill reduces the incentive for generating companies to reduce their output**.**
- While the more stringent SO_2 cap in the Carper bill tends to make low-sulfur western coal more attractive, the more stringent mercury cap has an opposite and larger effect. As a result, western coal production under the Carper 3-P sensitivity case is projected to be 14 percent lower than in the Reference case in 2020, while eastern coal production is projected to be 4 percent above the Reference case level. Even with these changes from the Reference case, both eastern and western coal production in 2020 are expected to be about the same or above current levels of production.
- To reduce SO_2 emissions, 72 to105 GW of capacity are expected to add SO_2 scrubbers, while 140 to 166 GW are expected to add SCRs, primarily for NOx removal, and 129 to137 GW of supplemental fabric filters with activated carbon injection are added by 2020.
- In the Carper 3-P sensitivity case, the NO_x allowance price in 2020 is projected to be $1,935 per ton, roughly in between the east and west regions' NO_x allowance prices under Clear Skies. In 2020, SO_2 allowance prices are projected to be $1,249 per ton, nearly $300 per ton higher than under Clear Skies because of the tighter SO_2 target in the Carper bill. In the full Carper bill cases the NOx, SO2, and mercury allowance prices tend to be lower than in this sensitivity case because the CO_2 emission target leads to lower coal use.
- The Hg allowance price in the Carper 3-P sensitivity case is projected to be $29,692 per pound in 2020, higher than the range of Hg allowance prices in the Carper cases with CO_2 limitations where there are larger reductions in coal use, but lower than the Hg allowance price in the Clear Skies analysis, even though Carper has a more stringent Hg emissions limit and no safety valve. The Carper bill requirement that all coal plants achieve at least 70 percent Hg removal after 2012 drives this outcome.
- In the Carper 3-P sensitivity case, the discounted change in resource costs over the 2005 to 2025 time per are projected to be $51.7 billion. In the same case, electricity prices in 2020 are projected to be 1.9 percent higher than in the Reference case. Due to the output-based allowance approach used in the Carper bill, the projected impact on electricity prices for this case is lower than that for the Clear Skies bill that caps the same three pollutants, even though Carper has more stringent caps and timetables.

Additional Context for the Report

- As in all projections, considerable uncertainty exists.
- There have been few full-scale demonstrations of some of the plant configurations that are necessary to meet the requirements of the proposed bills.
- The measurement of and cost of controlling mercury emissions is an important area of uncertainty in this analysis. In recent years, significant resources have been devoted to studying the factors that influence coal plant mercury emissions and technologies that could be used to reduce them. However, many questions remain to be answered.
- The potential availability and cost of greenhouse gas offsets is an important area of uncertainty when analyzing the impacts of the Carper bill with its limit on CO_2 emissions. There is uncertainty both about what offsets might cost and what sorts of rules and regulations the independent review board called for in the Carper bill would establish for acceptable international trading programs and offset projects.
- The Reference Case used in this report includes final regulatory action under existing laws. However, consistent with standard EIA practice requiring policy neutrality in baseline projections, it does not include pending or proposed actions, such as the maximum achievable control technology (MACT) standards for mercury emissions from power plants. The implementation of such actions could affect emissions, generator costs, and electricity prices during the projection period even if there is no new legislation.
- The EIA analysis contained in this report, like other EIA analyses, focuses on the impact of the two bills under review on energy choices made in all energy-using 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 emissions reductions.

Background

Analysis Request

On July 30, 2003, Senator James M. Inhofe requested "the Energy Information Administration to undertake analyses of S.843, The Clean Air Planning Act of 2003, introduced by Senator Thomas Carper, and S.485, Clear Skies Act of 2003."[1] Senator Inhofe specifically asked the Energy Information Administration (EIA) to address the impact on sulfur dioxide, nitrogen oxide, mercury, and carbon dioxide emissions nationally and regionally, the marginal costs of reducing each emission, the amount of emissions control equipment needed, and the costs and electricity price impacts of each bill. Senator Inhofe also asked EIA to analyze S. 485 with and without the mercury provisions and S. 843 with and without the mercury and carbon dioxide provisions.

Bill Summary

Both bills require reductions in the emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg) from electricity generating plants.[2] In addition, S. 843 (hereafter referred to as the Carper bill) also calls for reductions in power sector emissions of carbon dioxide (CO_2). With respect to SO_2, NO_x, and Hg, the emissions caps and reduction timetables differ, but both bills generally call for multi-phase, cap-and-trade emission reduction programs (Table 1 and Figures 1 through 4) covering electricity-generating facilities larger than 25 megawatts. For SO_2 and Hg the emissions caps take effect earlier and end up more stringent in the Carper bill than they do under Clear Skies. For NO_x the final caps are the same, but the timetable of the emissions caps differs. Relative to 2000 emission levels, Clear Skies calls for reducing SO_2 emissions by 73 percent while the Carper bill calls for an 80-percent reduction. For NO_x both the Clear Skies and Carper bills call for a 67-percent reduction from the 2000 emission level. For mercury, Clear Skies calls for a 70-percent reduction from the 2000 level while the Carper bill calls for an 80-percent reduction. The Carper bill calls for reducing CO_2 emissions from electricity generating plants in 2009 to the level projected in EIA's Reference case for 2006 and further reducing them to the actual 2001 level by 2013. Relative to EIA's projected CO_2 emissions from electricity generators in the Reference case, the 2013 target in the Carper bill would require a 24-percent reduction in 2020 and a 30-percent reduction in 2025. However, the Carper bill allows generators to comply with the CO_2 target using allowances from other domestic or international greenhouse gas trading programs or by investing in projects that reduce greenhouse gas emissions or increase sequestration.

[1] See Appendix A for a copy of the requesting letter.

[2] For pdf versions of the bills see, S. 485 - http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s485is.txt.pdf, S. 843 - http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf

Table 1. Emission Targets in Clear Skies and Carper Bills

Emission	S. 485, Clear Skies Targets	S. 843, Carper Targets
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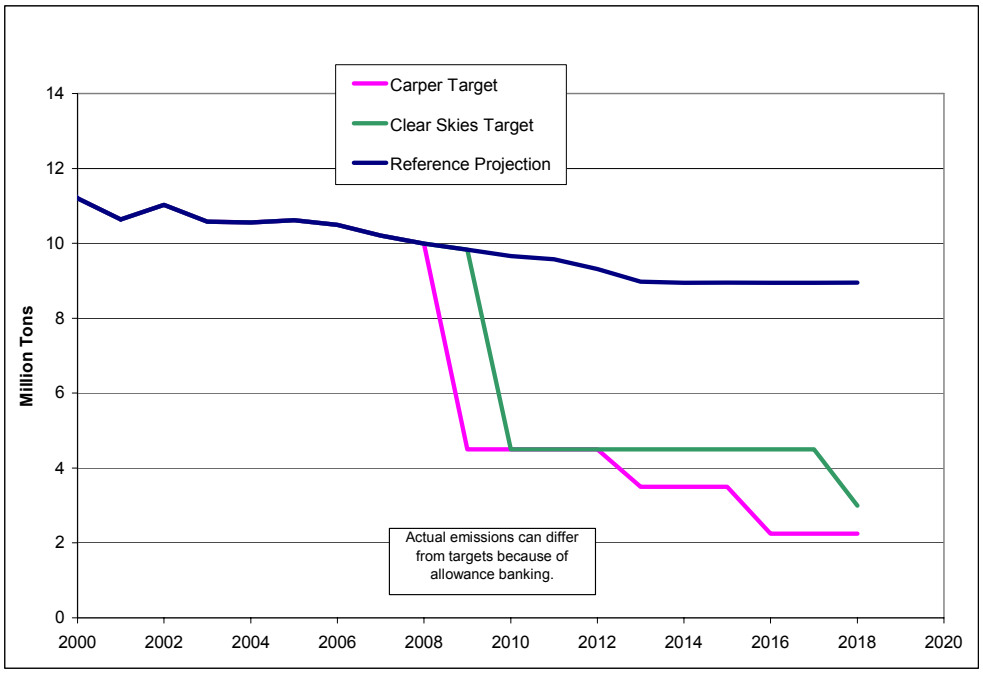
Carbon Dioxide (CO_2)	No cap	636 million metric tons carbon equivalent in 2009 612 million metric tons carbon equivalent in 2013[3]

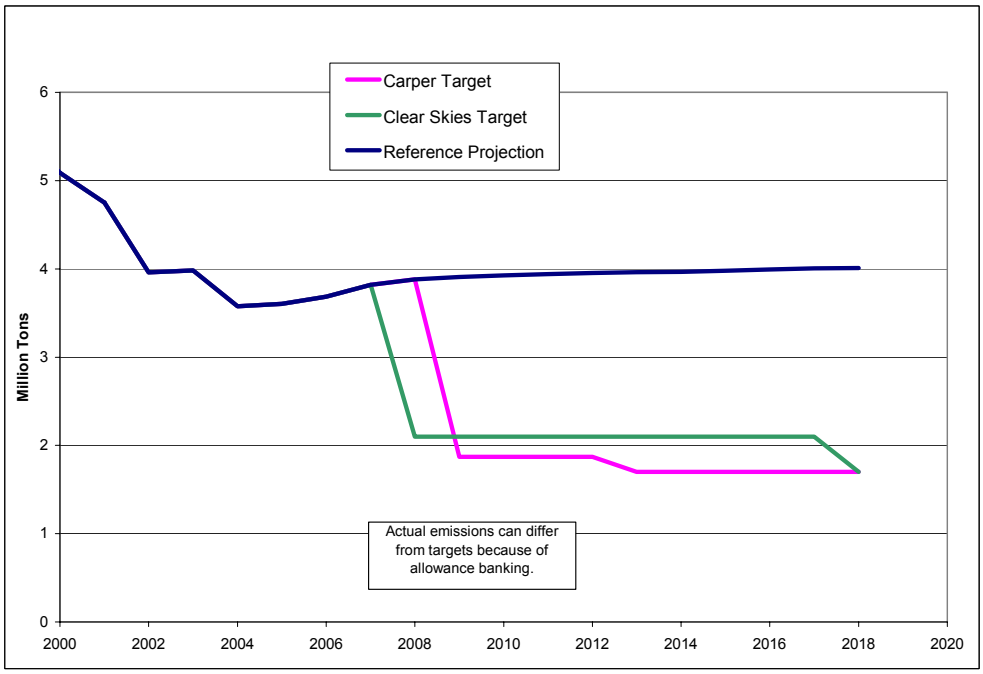
1) Limit on NO_x emissions is split between 2 regions – 0.538 million tons in the West and 1.562 million tons in the East in 2008 with a further reduction to 1.138 million tons in the East in 2018.
2) Minimum facility-specific reductions are also required. Between 2009 and 2012 the minimum reduction is 50 percent, while after 2012 it is 70 percent.
3) 2009-2012 limits are based on EIA projected emissions for 2006; the limit for 2013 and subsequent years is based on actual 2001 emissions.

Figure 1. Sulfur Dioxide Emission Projections and Targets



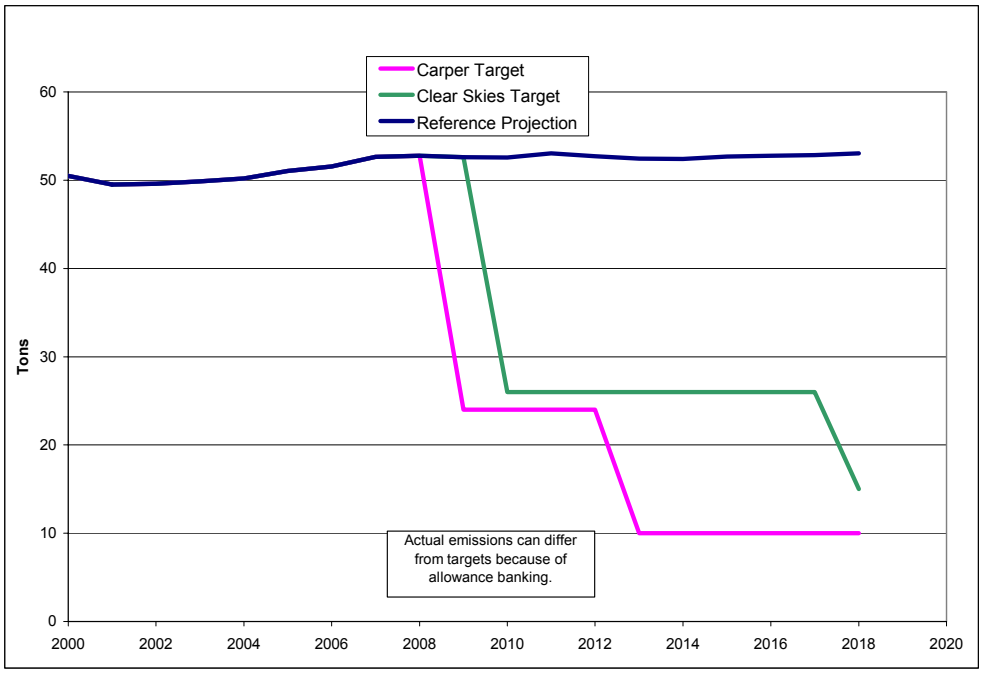
Sources: Reference projection: National Energy Modeling System run, imbase.d073103b. Targets from respective bills.

Figure 2. Nitrogen Oxide Emission Projections and Targets



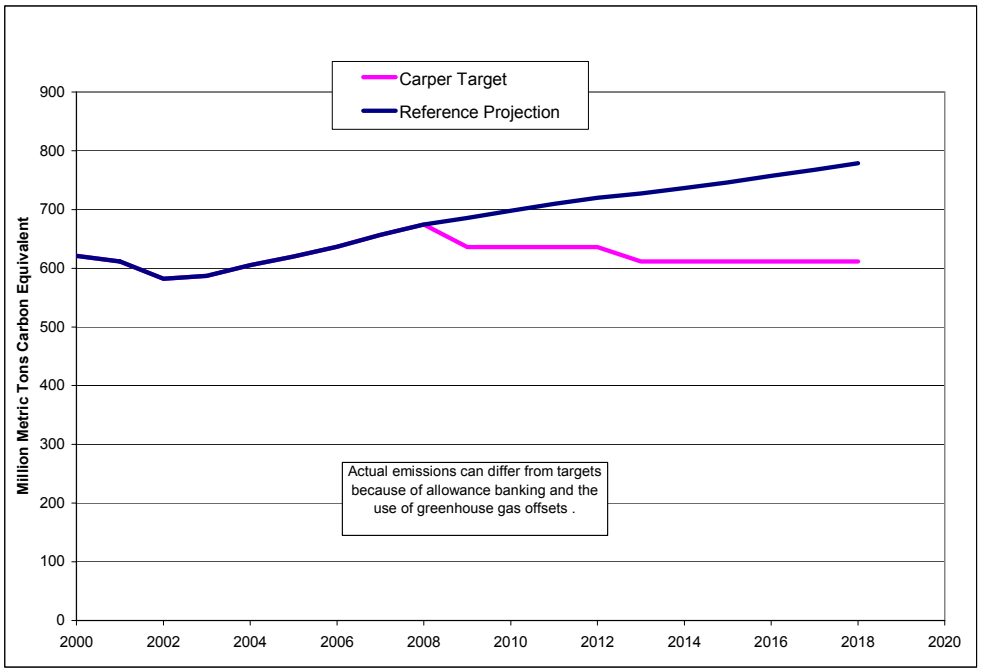
Sources: Reference projection: National Energy Modeling System run, imbase.d073103b. Targets from respective bills.

Figure 3. Mercury Emission Projections and Targets



Sources: Reference projection: National Energy Modeling System run, imbase.d073103b. Targets from respective bills.

Figure 4. Carbon Dioxide Emission Projections and Targets



Sources: Reference projection: National Energy Modeling System run, imbase.d073103b. Target from Carper bill.

Both bills rely primarily on emissions cap-and-trade programs to meet their specified emission targets. Under such programs, each power plant must annually submit an allowance for each unit (i.e., tons, metric tons, pounds, or ounces) of emissions. Under such programs, market forces will determine allowance prices, and each covered entity is free to determine its optimal compliance strategy. They can choose to reduce their emissions or purchase allowances from others who have reduced their emissions below the level of allowances they hold. They can also choose to overcomply in an earlier year and to use those allowances in a future period, i.e., bank allowances.

Besides differences in the timing and stringency of the emissions caps, there are several other important differences between the two bills. These include:

- Allowance price safety valves and excess emissions penalties. Clear Skies sets excess emissions penalties to the most recent auction price for each emission each year. It also sets a safety valve for each emission. Facilities can purchase allowances from the government at these safety valve prices if they are not available in the market at lower prices. The safety valve is $4,000 per ton for SO_2 and NO_x and $2,187.50 per ounce ($35,000 per pound) for mercury. The safety valve puts a limit on the respective allowance prices and, if utilized, will cause the

emission targets to be exceeded.[3] The Carper bill does not set safety valves, but imposes excess emissions penalties: $2,000 (1990 dollars) per ton for SO_2, $5,000 per ton for NO_x, $10,000 per pound for mercury, and $100 per ton for CO_2 (penalty fees are to be adjusted for inflation). In addition, excess emissions must be made up in the following year or a period of time prescribed by the Administrator of the Environmental Protection Agency (EPA).

- Facility-specific mercury limits. The Carper bill requires that all coal facilities either remove a minimum percentage (50 percent between 2009 and 2012, and 70 percent in 2013 and later) of the mercury in the coal burned or meet an output-based rate to be set by the EPA Administrator.[4] The efforts taken to comply with the requirement to remove a certain percentage of the mercury in the coal reduce the additional efforts needed to meet the overall emissions cap and will lead to lower allowance prices but higher industry cost than would occur with only a cap-and-trade program.
- Output-based standards for older plants. Beginning in 2020, the Carper bill requires that plants that began construction before August 17, 1971, must emit no more than 4.5 pounds per megawatthour of SO_2 and 2.5 pounds per megawatthour of NO_x. This provision is not explicitly modeled in this analysis, but because of the relatively stringent limits on national NO_x and SO_2 emissions that will be in place by 2020 in the Carper bill, most plants are expected to comply with these limits.
- Allowance programs
    - Clear Skies generally allocates NO_x, SO_2, and Hg allowances to existing units based on historical heat input. This is often referred to as "grandfathering" since the allocation is based on historical fuel use. Over time the allocation gradually shifts to an auction with the auction revenue going to the government.[5] Allowances are not allocated to new units.
    - For SO_2, the Carper bill also allocates allowances using a grandfathering approach, while for NO_x, Hg, and CO_2, allowances are allocated on an output basis (i.e., pounds per megawatthour of electricity produced) that is continually updated based on the most recent three years of each facility's generation. Essentially this is a rolling three-year generation performance standard (GPS) for NO_x, Hg, and CO_2. Under the Carper bill, allowances are also allocated to new units until they have operated for three years and become part of the regular GPS program.[6] The GPS programs in the Carper bill will impact the cost and price impacts of meeting the emission targets. In general, a dynamic GPS, which is updated continuously as

[3] Allowances sold directly under the safety valve provisions are to be withheld from allowances that otherwise would have been auctioned. However, if this exhausts the pool available in the auction for three consecutive years, the Environmental Protection Agency is required to conduct a study "to determine whether revisions to the relevant allowance trading program are necessary and shall report the results to the Congress."

[4] In this analysis it is assumed that all facilities will have to achieve a minimum of 70-percent removal of the mercury in the coal.

[5] S. 485 specifies that the proceeds of any auction shall be deposited in the United States Treasury.

[6] The size of the new unit reserve is to be determined by the Administrator of the Environmental Protection Agency and the Secretary of Energy. In this analysis it is assumed that new covered units receive allowances at the same output rate as existing covered units.

each facility's generation changes, provides an incentive to facilities to increase their output so that they receive more allowances in the future. This "output subsidy" lowers the electricity price impacts of reducing emissions, but increases the cost impacts.[7] As one expert said, "output based rebating sacrifices some of the efficiencies of market-based environmental policies. Allocating by market share essentially provides a subsidy to output, which creates a bias away from output substitution and toward emissions rate reduction. The result is a higher marginal cost of control, a lower equilibrium output price, and a greater cost of achieving any given level of emissions reduction, compared to an efficient policy. The size of the welfare loss from this distortion depends on how much emissions reduction would normally be performed by output substitution."[8] In layman's terms this means if facilities are given allowances based on their output (generation) they will tend to produce more than they otherwise would have.

The output subsidy associated with a GPS derives from its impact on covered generators' operating costs. For example, a typical coal plant produces approximately 0.25 metric tons of carbon per megawatthour. As a result, a $100 carbon fee would raise its operating cost by $25 per megawatthour. However, under a GPS, the plant will be allocated some allowances for each megawatthour it generates. If it is assumed that the GPS is 0.15 metric tons of carbon per megawatthour, calculated by dividing the CO_2 emissions cap by the generation of all covered plants, the impact on the coal plant's operating costs of a $100 carbon fee is only $10 per megawatthour ((0.25 – 0.15) X $100). If this plant were setting the market-clearing price of electricity, consumers would face a smaller price increase under the GPS, $10 per megawatthour rather than $25 per megawatthour, and have less incentive to reduce their use of electricity. This would lead to greater generation (output) from the power sector under a GPS allocation program, than under a grandfathering allowance program.

- The Carper bill establishes an independent review board to certify projects outside of the U.S. power sector as eligible for additional CO_2 allowances. It also allows the use of allowances from recognized international CO_2 trading programs. Electricity facilities are able to use these allowances from certified projects as well as allowances from other U.S. or recognized international CO_2 trading programs (all referred to as offsets in this report) to meet their CO_2 targets rather than directly reducing their

[7] For more discussion of the impacts of various emission allocation approaches see Beamon, Leckey, and Martin, *Power Plant Emissions Reductions Using a Generation Performance Standard* , web site http://www.eia.doe.gov/oiaf/servicerpt/gps/pdf/gpsstudy.pdf;and Burtraw, *Carbon Emission Trading Costs and Allowance Allocations: Evaluating the Options* ,web site http://www.rff.org/resources_archive/pdf_files/145_burtraw.pdf.

[8] C. Fischer, *Rebating Environmental Policy Revenues: Output-based Allocations and Tradable Performance Standards* (Washington, DC: Resources for the Future, January 21, 1999).

own emissions. In addition to existing fossil generators, new fossil fuel and renewable units receive CO_2 allowances.[9]

To analyze the availability and cost of greenhouse gas offsets, this analysis incorporates a set of curves representing the potential for other greenhouse reductions and sequestration. These curves, referred to as marginal abatement curves (MACs), were obtained from EPA's Office of Air and Radiation. Essentially, MACs are simplified, reduced-form representations of emissions compliance potential as a function of a single variable, the allowance price. Because there is great uncertainty in developing these MACs, a range of results is provided based on alternative assumptions.[10]

Analysis

EIA analyzed the bills using the National Energy Modeling System (NEMS). The Reference case for the analysis was based on EIA's *Annual Energy Outlook 2003 (AEO2003)*.[11] It was updated in June 2003 to reflect changes in electric generating capacity since the *AEO2003* was completed; to incorporate revised expectations about near-term trends in natural gas prices; to incorporate revised mercury emissions factors; and to reflect recent changes in corporate average fuel economy (CAFE) standards. In addition potential CO_2 offsets from reductions in other greenhouse gases and sequestration projects were reviewed.

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. Thus, they provide a policy-neutral Reference case that can be used to analyze policy initiatives. 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. In addition to the uncertainties inherent in the Reference case projection itself, there are several important uncertainties in evaluating the bills. Of particular concern in this analysis are the cost and performance of technologies to remove mercury and the availability and cost of greenhouse gas offsets.

In order to respond to the requests from Senator Inhofe, the following cases were analyzed for the Clear Skies and Carper bills.

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[9] The emissions cap in the Carper bill is given in units of CO_2, but additional CO_2 allowances can come from projects that reduce any of the main six greenhouse gases specified in the Kyoto Protocol or increase sequestration.

[10] For more information about the representation of marginal abatement curves in the National Energy Modeling System see Energy Information Administration, *Analysis of S. 139, the Climate Stewardship Act of 2003*, Appendix B, SR/OIAF/2003-3, (Washington, DC, June 2003).

[11] Energy Information Administration, *Annual Energy Outlook 2003*, DOE/EIA-0308(2003), (Washington, DC, January 2003).

- **Reference**

- Clear Skies Bill Cases

    - **Clear Skies 3-P -** NO_x, SO_2, and Hg caps with the safety valves

    Clear Skies bill sensitivity cases requested by Senator Inhofe

    - **Clear Skies 2-P -** NO_x and SO_2 caps only
    - **Clear Skies 3-P No Mercury Safety Valve** - NO_x, SO_2, and Hg caps without the mercury safety valve.

- Carper Bill Cases
    - **Carper 4-P High Offset** - NO_x, SO_2, Hg, and CO_2 caps with high greenhouse gas offsets. Assumes that the independent review board allows electricity generators to use certified allowances from 1) Annex 1 countries, 2) projects that reduce the emissions of other greenhouse gases in the United States, and 3) U.S. and international sequestration projects.[12]
    - **Carper 4-P Mid Offset** - NO_x, SO_2, Hg, and CO_2 caps with mid greenhouse offsets. Assumes that the independent review board allows electricity generators to use certified projects that reduce the emissions of other greenhouse gases in the United States.
    - **Carper 4-P No Offset** - NO_x, SO_2, Hg, and CO_2 caps without any CO_2 offsets. Assumes that electricity generators must directly reduce their emissions to the targets in the Carper bill.

    Carper bill sensitivity cases requested by Senator Inhofe

    - **Carper 2-P** - NO_x and SO_2 caps only
    - **Carper 3-P** - NO_x, SO_2, and Hg caps only

    The assumptions about offsets in the three Carper 4-P cases are not meant to be predictions about how the independent review board established in the Carper bill might act. Rather they provide a range of results regarding the availability and cost of offsets, which are highly uncertain. They should be seen as representing the uncertainty about the potential availability and cost of offsets.

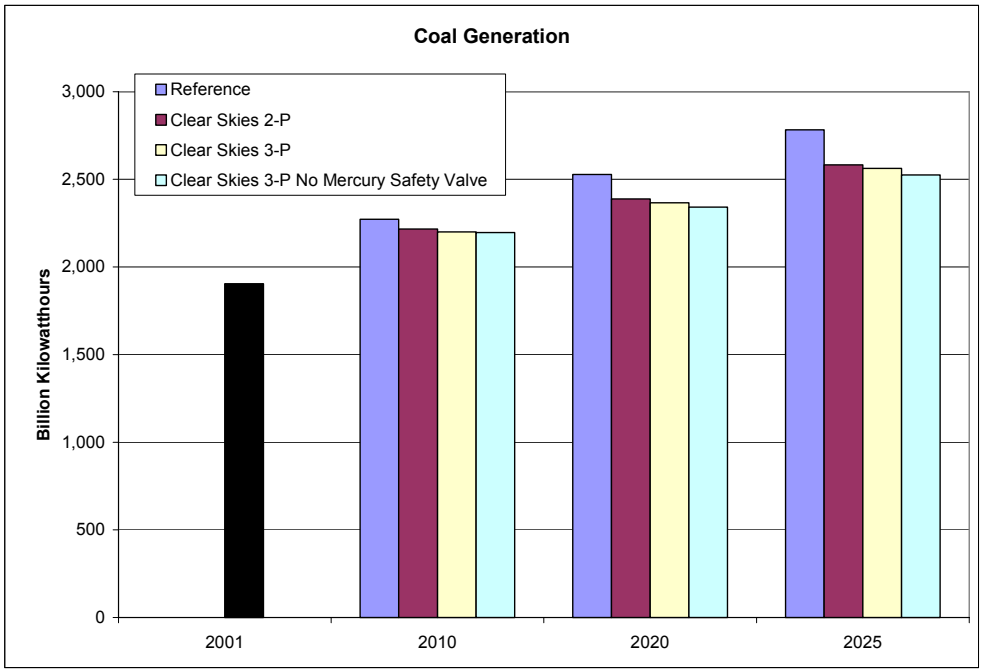
[12] The Annex I countries are the 15 European Union countries plus Australia, Bulgaria, Canada, Czech Republic, Estonia, Hungary, Iceland, Japan, Latvia, Liechtenstein, Monaco, New Zealand, Norway, Poland, Romania, Russian Federation, Slovakia, Switzerland, and the United States.

Generation and Fuel Use

Coal

Power sector efforts to reduce NO_x, SO_2, and Hg emissions are projected to lead to lower coal generation and increased generation from natural gas. For example, if the NO_x and SO_2 provisions of Clear Skies were imposed, coal generation in 2010 is projected to be 2.4 percent lower than it otherwise would have been (Figure 5). By 2020, this difference is projected to be 5.6 percent. When the Hg cap with the safety valve is also imposed, the change in coal generation is projected to be slightly larger, falling to 6.4 percent below Reference case projections in 2020 and 7.4 below the Reference case level when the Hg safety valve is removed. However, even with these changes, coal generation in 2020 and 2025 is projected to be well above current levels with or without Clear Skies.

Figure 5. Coal Generation In Clear Skies Cases

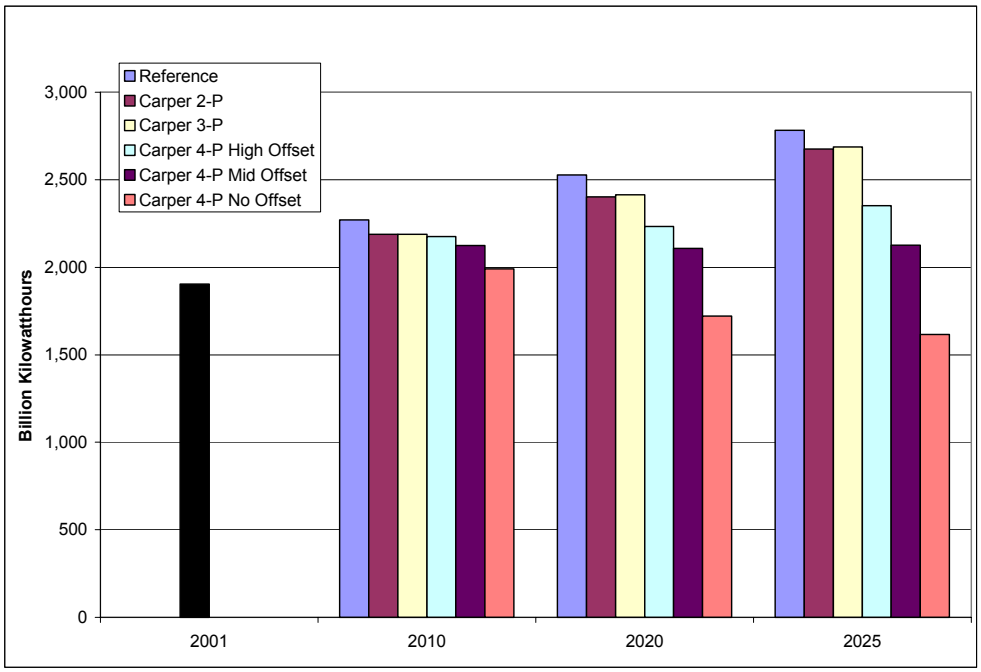


Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

The reduction in coal use in the Carper 2-P and 3-P cases is projected to be slightly smaller than in the comparable Clear Skies cases (Figure 6). Even though the SO_2 and Hg emissions caps in Carper are more stringent, the GPS allowance allocation scheme and the minimum facility-level removal requirements for mercury dampen the impact on coal that would otherwise be seen. As discussed in the background section, the GPS provides an output subsidy that leads facilities to rely more on emissions control technologies rather than reducing their output to comply with the emissions limits. In the Carper 3-P case, coal generation is actually projected to be slightly higher than in the Carper 2-P case because the allocation of mercury allowances to new coal plants, which

are assumed to remove 90 percent of the mercury in the coal they use, make them more economically attractive. Overall, coal generation in 2020 is projected to be 4.9 percent below the Reference case in the Carper 2-P case and 4.5 percent below in the Carper 3-P case.

Figure 6. Coal Generation In Carper Cases



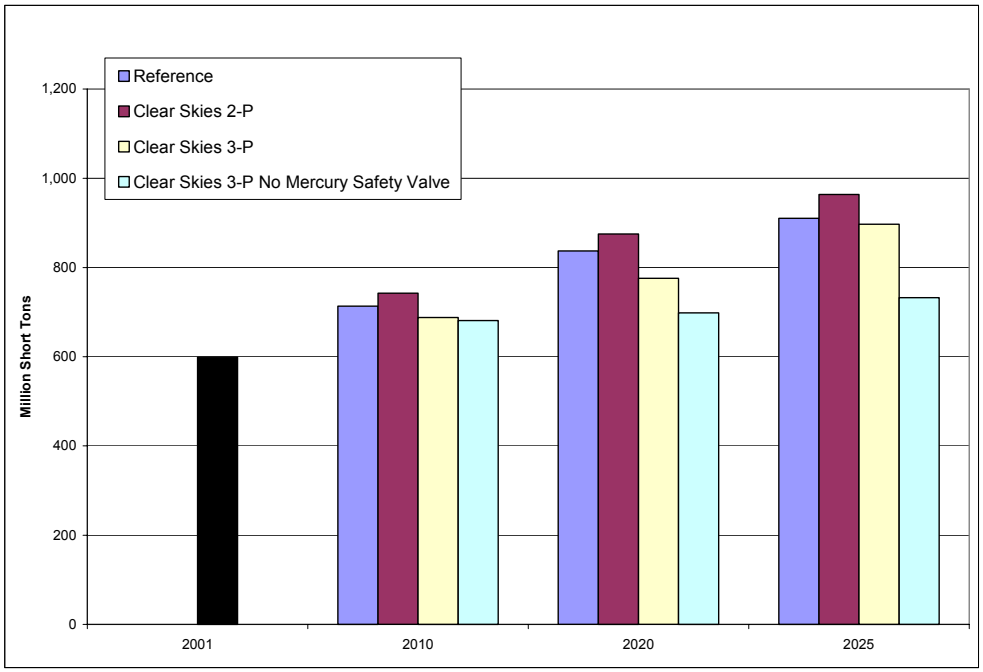
Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

The projected change in coal generation could be much larger in the Carper 4-P cases, but it is very sensitive to the availability and cost of CO_2 offsets. There is significant uncertainty about the potential price of CO_2 offsets. There is also uncertainty about the requirements the independent review board created in the Carper bill might establish before a project can be certified to receive additional CO_2 allowances and what might be required regarding the use of international programs. Across the three Carper 4-P cases, coal generation in 2020 is projected to be between 12 percent and 32 percent below the Reference case level. The low impact occurs if CO_2 offsets are readily available with their price growing from $4 per metric ton carbon equivalent (2001 dollars) in 2010 to $26 per metric ton in 2025. Conversely, if the U.S. power sector can not rely on offsets, the impact would be much larger, with the CO_2 allowance price growing from $66 per metric ton carbon equivalent in 2010 to $135 per metric ton in 2025.

In aggregate, the changes in coal production are expected to parallel the changes in coal generation in the Clear Skies cases. However, regional coal production is expected to react differently. In the Clear Skies 2-P case, western coal production is projected to be 4.5 percent higher in 2020 than in the Reference case because of the tighter SO_2 cap, which makes low-sulfur subbituminous western coal more attractive (Figure 7). In the

Clear Skies 3-P cases, particularly the one without the mercury safety valve, the pattern reverses with western coal production falling below Reference case levels. The imposition of a mercury cap makes western coal less attractive because it is more difficult to remove mercury from the lower rank (subbituminous and lignite) coals. In the Clear Skies 3-P case, western coal production is projected to be 7.4 percent below the Reference case level in 2020. This change widens to 16.6 percent in the Clear Skies 3-P case without the mercury safety valve. However, even with these changes, western coal production is projected to increase from current levels in all Clear Skies cases.

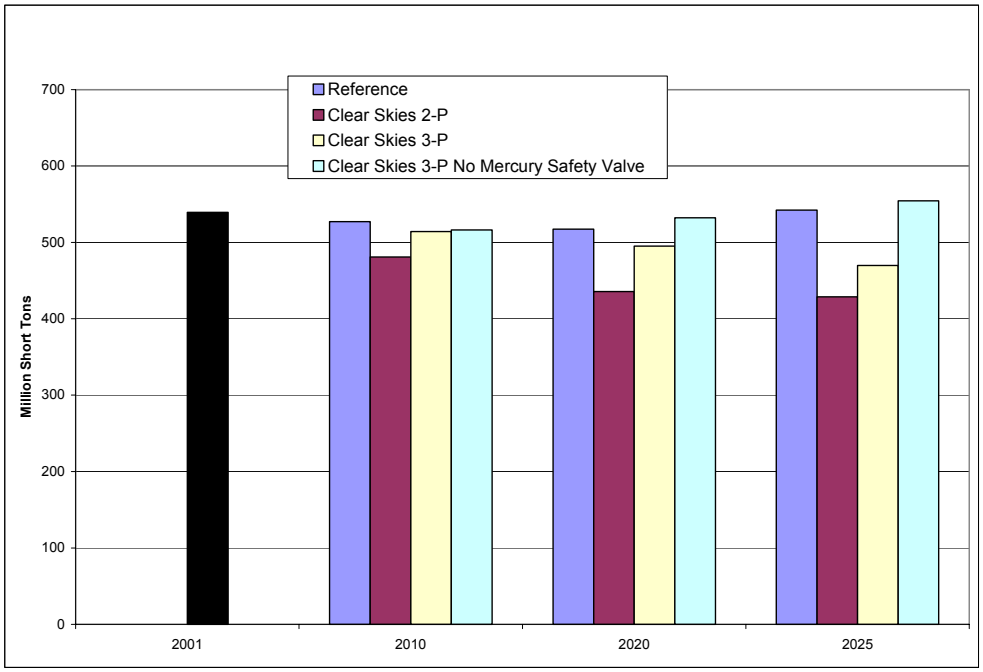
Figure 7. Western Coal Production in the Clear Skies Cases



Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

The projected changes in eastern coal production under Clear Skies are nearly the mirror opposite of those for western coal. In the Clear Skies 2-P case, the production of eastern bituminous coal is projected to be 15.8 percent below the Reference case level in 2020 as power plants switch to low-sulfur western coal to comply with the tightening SO_2 emissions cap (Figure 8). However, in the Clear Skies 3-P cases, particularly when the mercury safety valve is removed, the production of eastern bituminous coal is projected to be above the level seen in the Clear Skies 2-P case. Mercury is generally easier to remove from bituminous coal, so the imposition of a mercury cap makes such coal more economic. In 2020, eastern coal production is projected to be only 4.3 percent below the Reference case level in the Clear Skies 3-P case. In the Clear Skies 3-P case without the mercury safety valve, it is projected to be 2.9 percent above the Reference case level in 2020.

Figure 8. Eastern Coal Production in the Clear Skies Cases



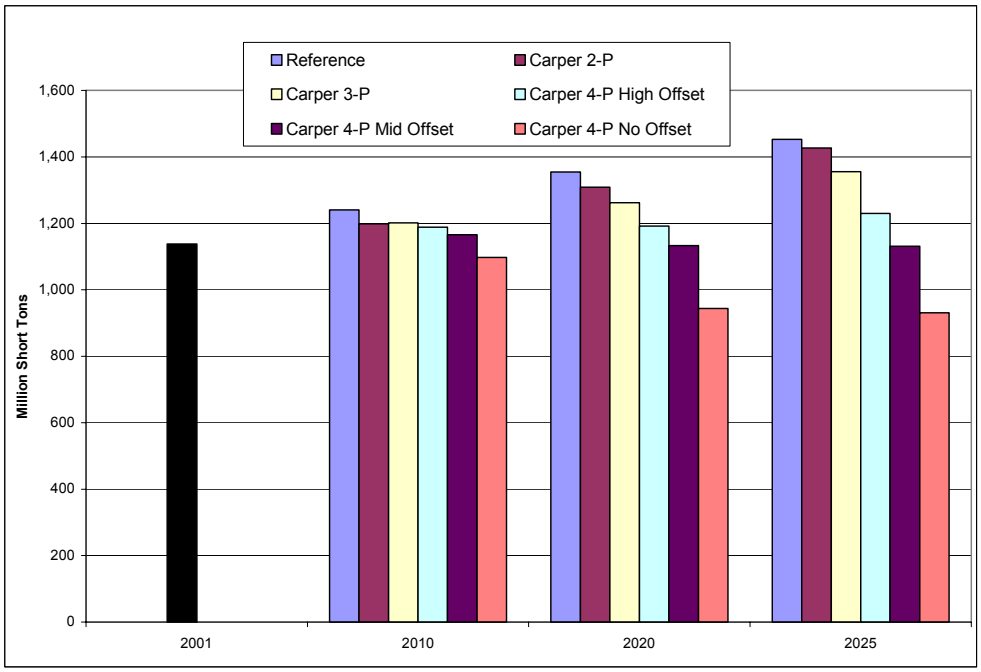
Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

As was the case with coal generation, the largest changes in projected coal production are seen in the Carper 4-P cases, particularly those with less offsets and higher CO_2 allowance prices (Figure 9). Because of its high carbon content relative to other fuels, coal generation and production are projected to be very sensitive to the CO_2 allowance price. For example, on a Btu basis, natural gas contains less than 60 percent as much carbon as coal does. In the Carper 4-P High Offset case, where power generators are assumed to be able to buy offsets from 1) Annex 1 countries, 2) projects that reduce the emissions of other greenhouse gases in the United States, and 3) U.S. and international sequestration projects (up to the limits of the Marrakech accords)[13], the CO_2 allowance price is projected to remain fairly low, reaching $26 per metric ton carbon equivalent in 2025, and coal production is projected to be 12 percent below the Reference case level in 2020 and 15 percent below the Reference case level in 2025. However, the impact on coal is much larger if CO_2 allowance prices are higher. In the Carper 4-P Mid Offset and Carper 4-P No Offset cases, coal production in 2020 ranges between 16 percent and 30 percent below the Reference case level.

[13] The Marrakech Accords, also known as the Seventh Conference of the Parties of the United Nations Framework Convention on Climate Change (COP 7 of the UNFCCC),were used to limit the quantity of agricultural/forestry offsets available to this international group to about 70 million metric tons per year, which were assumed to be available at $15 per ton carbon equivalent. See http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf page 247 for more details.

In the Carper 4-P Mid Offset and Carper 4-P No Offset cases, the impacts on employment in the U.S. coal industry are significant but less severe than the projected declines in production would suggest. Relative to the Reference case, the largest production cuts in these two cases are projected to occur in the western coalfields, which are considerably less labor-intensive than eastern operations. In the Carper 4-P Mid Offset and Carper 4-P No Offset cases, coal mine employment in 2025 is projected to be 10 percent and 27 percent less, respectively, than in the Reference case forecast. However, while there are coal industry job losses in these cases, increased employment in the natural gas and renewable fuels industries will at least partially compensate for the coal industry job loss.

Figure 9. Coal Production in the Carper Cases



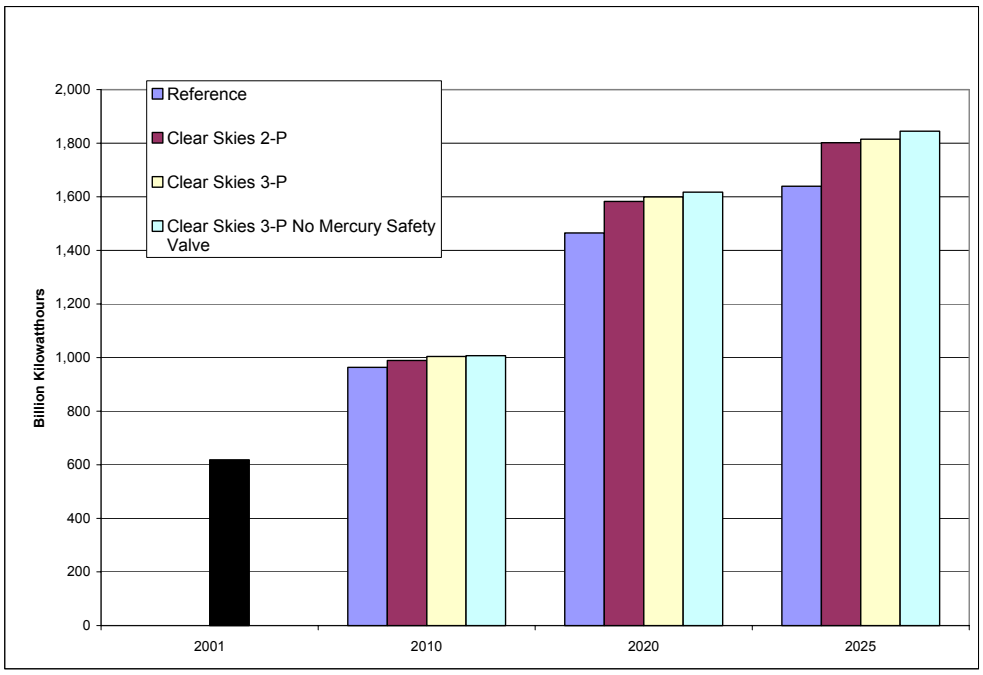
Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Natural Gas

In 2-P and 3-P cases, the impacts on natural gas generation and fuel use are projected to be nearly the opposite of those for coal. Imposing limits on power sector NO_x, SO_2, and Hg emissions is projected to lead to an increase in natural gas use in the power sector (Figure 10). Under Clear Skies, natural gas generation in 2020 is projected to 8.1 percent above the Reference case level in the 2-P case. The increase is 9.2 percent in the Clear Skies 3-P case but grows to 10.4 percent in the Clear Skies 3-P case without the mercury safety valve. The increase in gas use is projected to lead to higher natural gas imports, both liquefied natural gas (LNG) and pipeline imports from Canada. For example, in the

Reference case, natural gas imports are projected to reach 6.8 trillion cubic feet in 2020, while in the Clear Skies 3-P case, they reach 7.6 trillion cubic feet.

Figure 10. Natural Gas Generation in the Clear Skies Cases

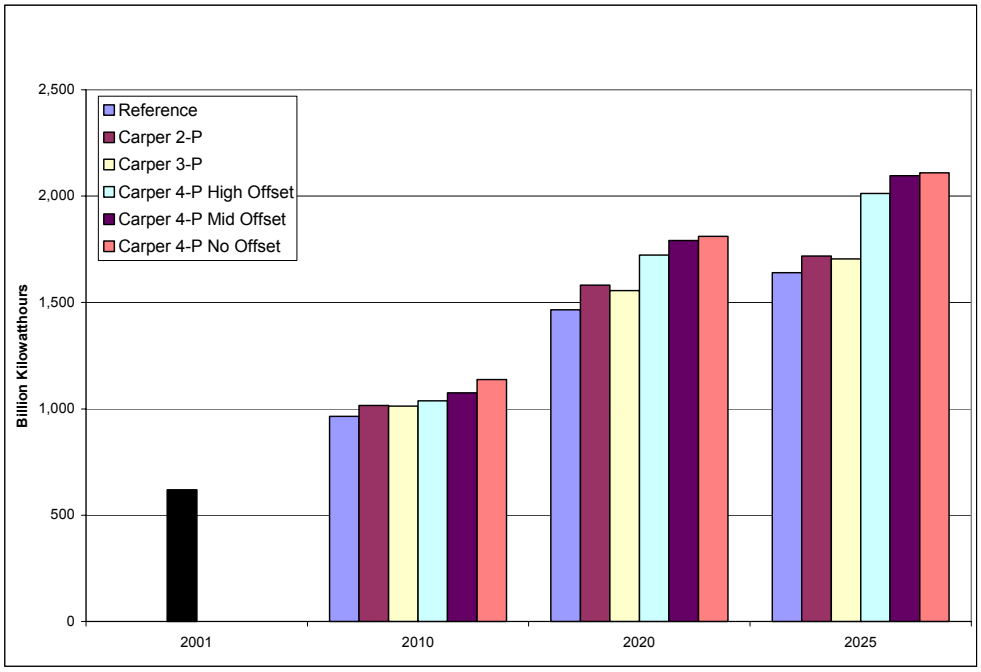


Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

Natural gas is projected to see an even larger change if a CO_2 cap is imposed. As with coal use, the increase in gas generation and fuel consumption that occurs in the Carper 4-P cases is sensitive to the cost and availability of CO_2 offsets. In the Carper 4-P cases, the increase in natural gas generation in 2020 ranges from 18 percent to 24 percent, much larger than in any of the Clear Skies or Carper 2-P and 3-P cases (Figure 11).

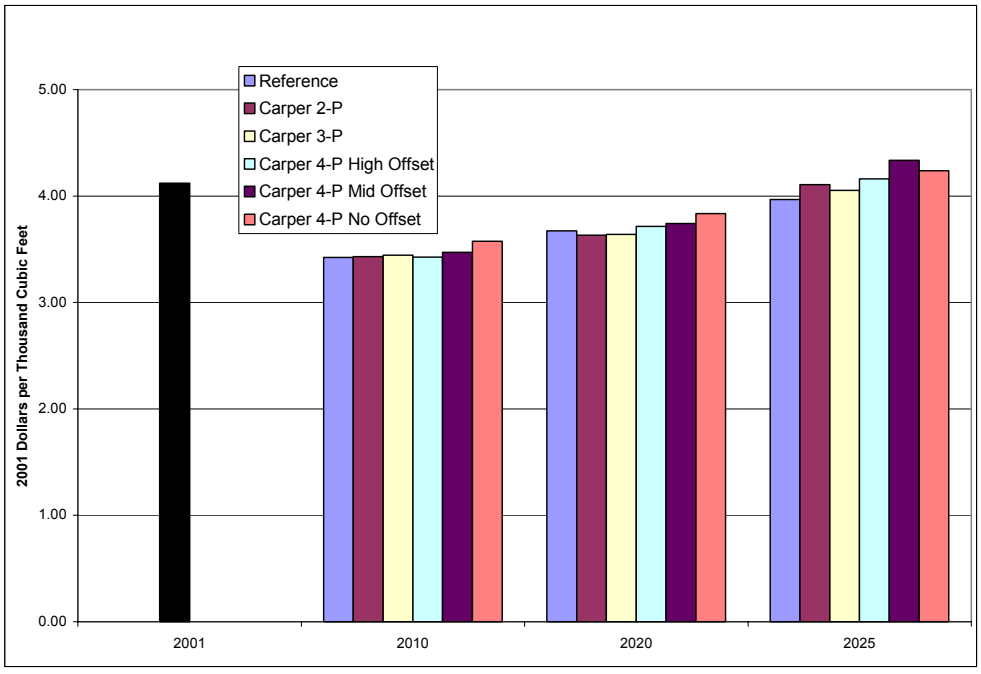
Increased natural gas generation is projected to lead to higher natural gas prices, particularly in the later years in the 4-P cases. In the Clear Skies 2-P and 3-P cases, natural gas wellhead prices are projected to show very little change from Reference case levels through 2020. However, in 2025 they are projected to be between 3.4 percent and 4.7 percent higher. In the Carper 4-P cases, the change from the Reference case in 2020 ranges from 1.2 percent to 4.4 percent. By 2025 the change from the Reference case ranges from 4.9 percent to 9.2 percent in the Carper 4-P cases (Figure 12). The difference in the variability in natural gas prices in Figure 12 is due to the timing of the expansion and opening of LNG facilities and the development of the Alaskan Natural Gas Transportation System. As discussed in the next section, in the Carper 4-P Mid and No Offset cases, the increase in natural gas generation relative to the Carper 4-P High Offset case is relatively small because renewable fuels become attractive in these cases.

Figure 11. Natural Gas Generation in the Carper Cases



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Figure 12. Natural Gas Wellhead Prices in the Carper Cases

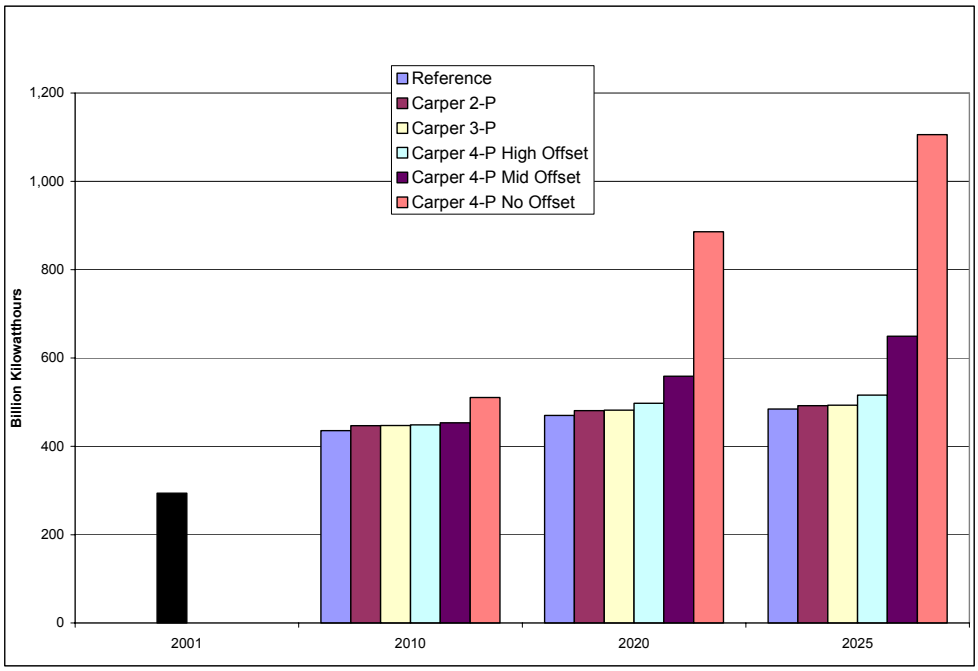


Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Renewable Fuels

Besides coal and natural gas, the use of other fuels for electricity is not expected to be significantly impacted in any of the 2-P or 3-P cases. However, in the Carper 4-P cases, particularly the case without carbon offsets, renewable fuel use is expected to be much higher than in other cases (Figure 13). New renewable fuel plants become attractive in the Carper 4-P cases because they are carbon free and they are given CO_2 allowances that can be sold to others who need them. In 2020, renewable generation in the Carper 4-P Mid Offset case is projected to be 19 percent above the Reference case level. In the Carper 4-P No Offset case, the difference is even larger in 2020, with renewable generation 89 percent above the Reference case level. The renewable fuels expected to play the largest role in the higher generation are biomass and wind.

Figure 13. Renewable Generation in the Carper Cases



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Generating Capacity and Emissions Control Retrofit Decisions

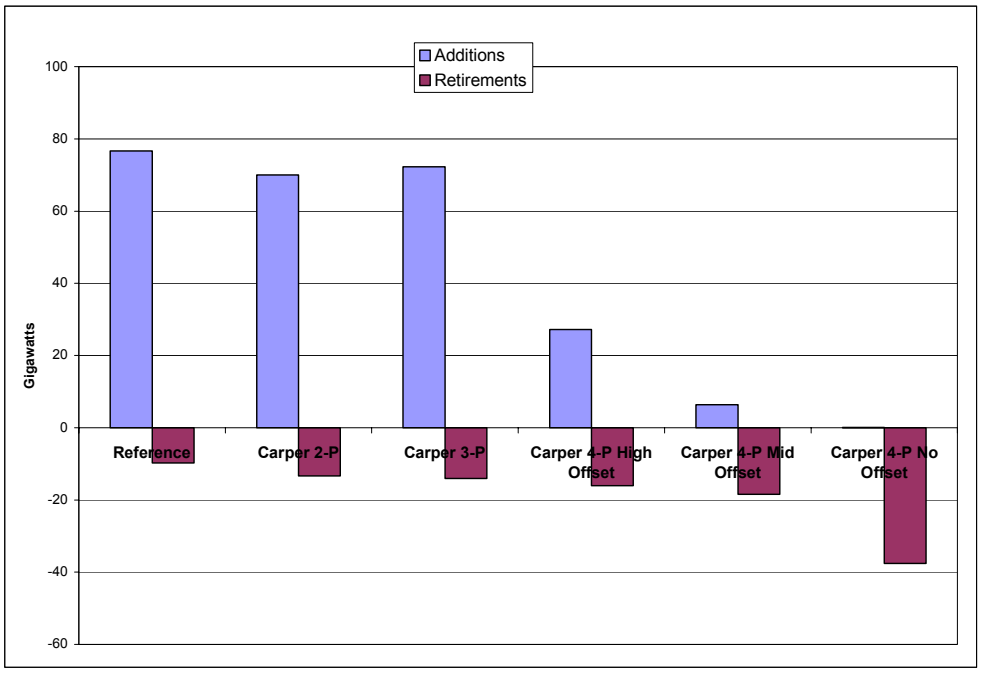
Capacity Additions

As might be expected, coal, natural gas, and renewable generating capacity changes in the various cases tend to parallel the generation and fuel use changes discussed previously. In the 2-P and 3-P cases, fewer new coal plants are built while more new

natural gas plants are built. Among the Clear Skies cases, new coal capacity additions through 2025 range from 50 gigawatts to 55 gigawatts, compared with 77 gigawatts in the Reference case. Because of the GPS emission allowance system used in the Carper bill, the reduction in coal capacity additions is lower in the 2-P and 3-P cases, ranging from 70 gigawatts to 72 gigawatts, only slightly below the 77 gigawatts projected in the Reference case. The output subsidy associated with the GPS and the fact that new coal plants receive NO_x and Hg allowances dampen the reduction in new coal plant builds that would otherwise occur.

The result is different in the Carper 4-P cases where, relative to the Reference case, new coal plant additions are much lower while retirements are higher (Figure 14). In fact, in the Carper 4-P case without offsets, no new coal plants are projected to be built while nearly 38 gigawatts of existing coal plants are retired.

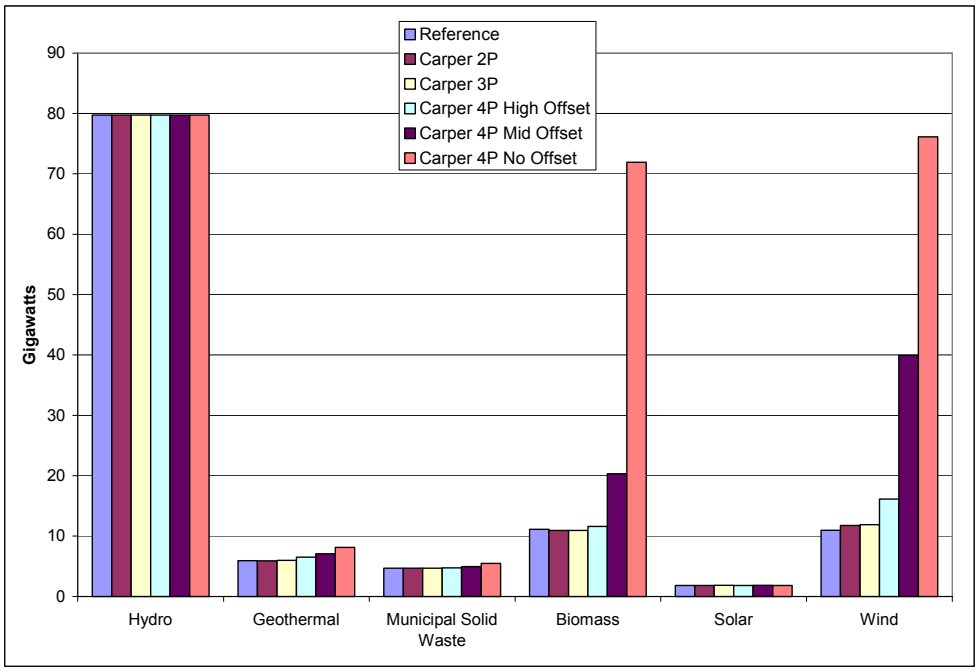
Figure 14. Cumulative Coal Plant Additions and Retirements in the Carper Cases, 2001-2025



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

In the Carper 4-P cases, new renewable capacity is projected to increase significantly, especially in the cases with fewer offsets available (Figure 15). The renewables expected to see the largest growth are biomass and wind. For example, among the Carper 4-P cases, biomass capacity in 2025 is projected to range from 12 gigawatts to 72 gigawatts, compared to 11 gigawatts in the Reference case. Similarly, wind capacity in 2025 in the Carper 4-P cases is projected to range from 16 gigawatts to 76 gigawatts, compared to 11 gigawatts in the Reference case.

Figure 15. Renewable Capacity in 2025 in the Carper Cases



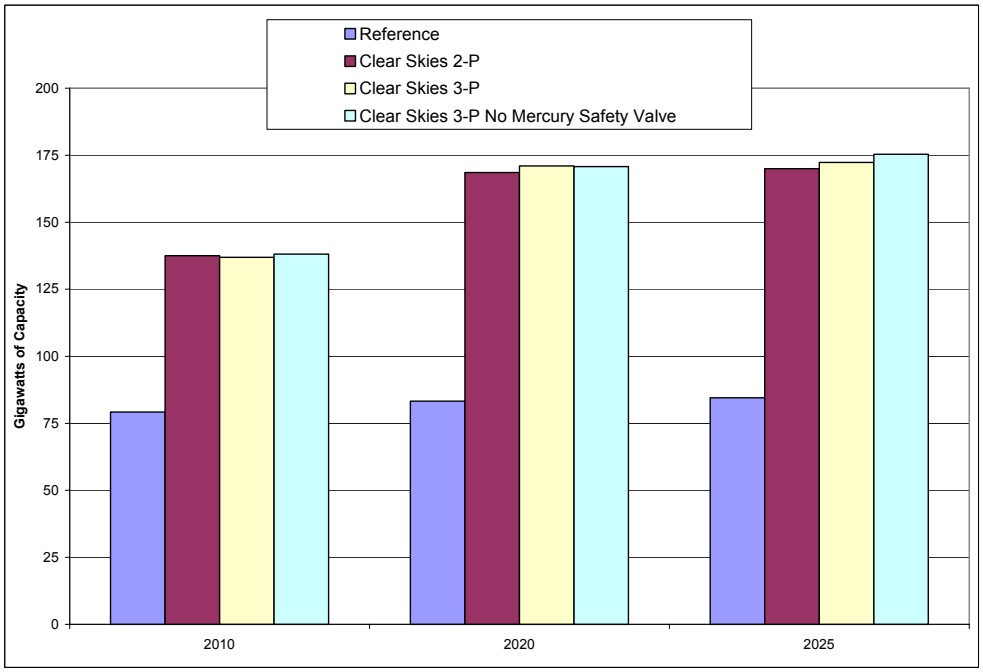
Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Emissions Control Equipment

While generating capacity investment decisions are not expected to change significantly in the 2-P and 3-P cases, power companies are projected to make significant investments in emissions control equipment to meet the NO_x, SO_2, and Hg caps in the bills. For NO_x control they are expected to turn mainly to selective catalytic control (SCR) systems. Under Clear Skies, power companies are projected to add between 170 gigawatts and 175 gigawatts of SCR capacity by 2025 (Figure 16). SCR additions are expected to be slightly higher in the 3-P cases because SCRs also help to reduce mercury emissions for some plants and coal types. With the same NO_x emissions cap, the amount of capacity expected to add SCRs in the Carper 2-P and 3-P cases is similar though slightly lower. Between the Carper 2-P and 3-P cases, the amount of capacity projected to add SCRs ranges from 163 gigawatts to 172 gigawatts.

In the Carper 4-P cases, the amount of capacity projected to add SCRs is generally lower than in the 2-P and 3-P cases because of the reduced use of coal in these cases due to the limit on CO_2 emissions. For example, in the Carper 4-P case without offsets, the amount of capacity projected to add SCRs is 140 gigawatts.

Figure 16. Cumulative SCR Additions in Clear Skies Cases, 2001 to Selected Dates

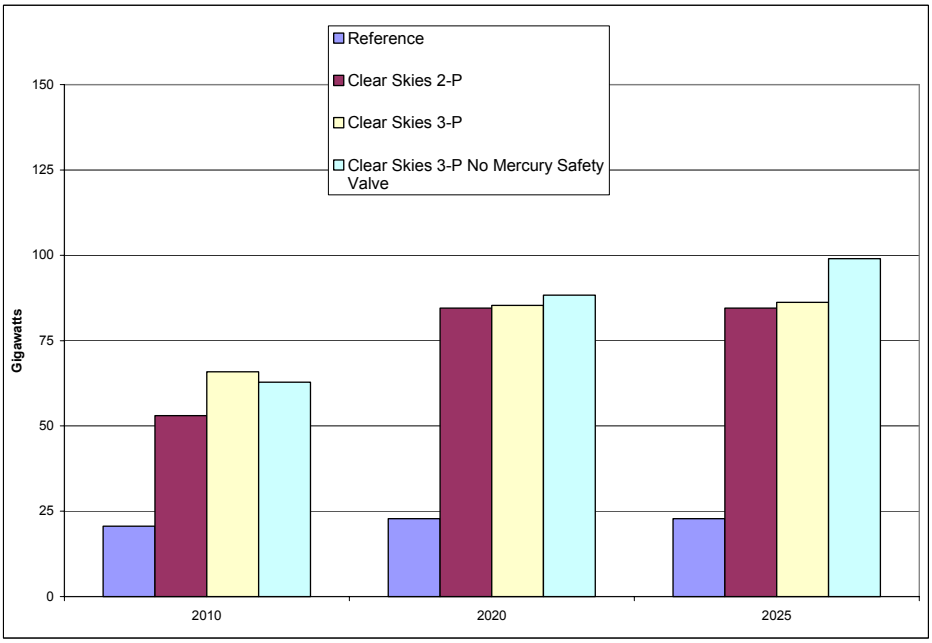


Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

In the Clear Skies 2-P and 3-P cases, power generators are projected to add between 85 gigawatts and 99 gigawatts of SO_2 scrubber capacity (Figure 17). With approximately 90 gigawatts of SO_2 scrubbers on existing plants today, approximately two-thirds of all coal capacity will have SO_2 scrubbers by 2025. Those plants not adding SO_2 scrubbers are expected to turn to low-sulfur coal to reduce their emissions.

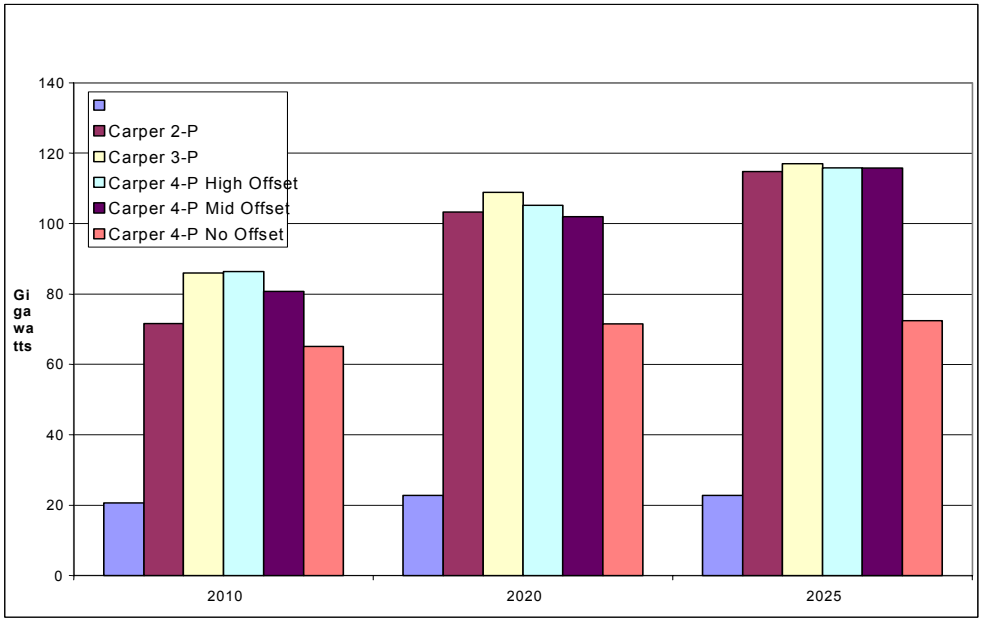
The tighter SO_2 emissions cap leads to greater additions of SO_2 scrubbers in the Carper 2-P and 3-P cases (Figure 18). In these cases, the amount of capacity adding SO_2 scrubbers is projected to range from 115 gigawatts to 117 gigawatts. As with the amount of SCRs added, the amount of SO_2 scrubbers expected to be added is lower in the 4-P cases, particularly in the Carper 4-P case without offsets. In this case, only 72 gigawatts of capacity are projected to add SO_2 scrubbers because of lower coal use.

Figure 17. Cumulative SO2 Scrubber Additions in Clear Skies Cases, 2001 to Selected Dates



Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

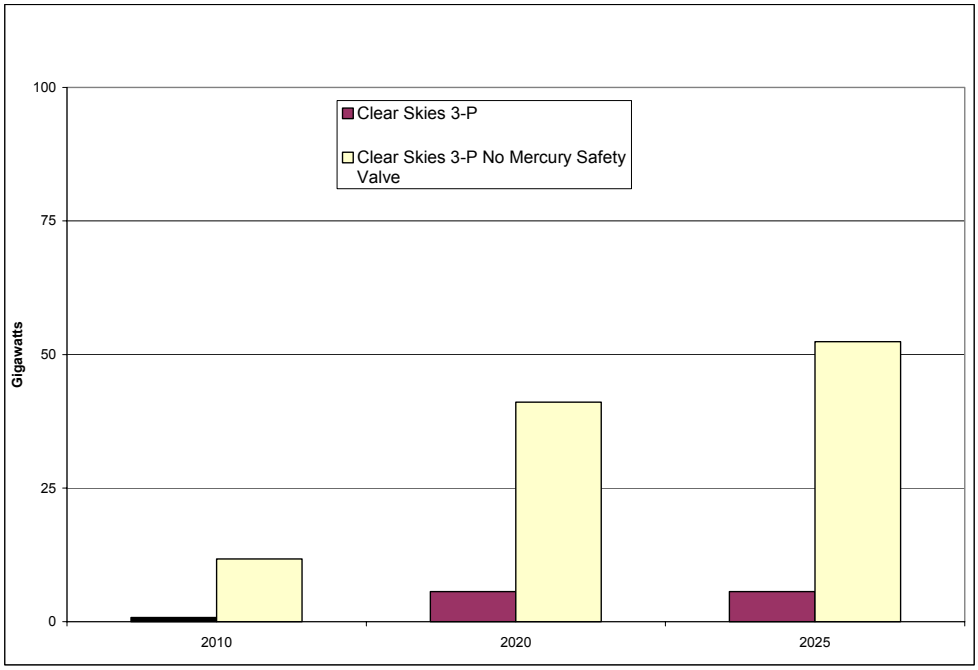
Figure 18. Cumulative SO_2 Scrubber Additions in Carper Cases, 2001 to Selected Dates



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

To meet the mercury emissions cap, power plants are expected to rely on the mercury reductions that come from equipment primarily designed to remove NO_x, SO_2, and particulates (which are often referred to as co-benefits) and the use of activated carbon injection (ACI) systems designed specifically to remove mercury. ACI can be used with existing particulate control devices, i.e., electrostatic precipitators or fabric filters, or with a supplemental fabric specifically designed to remove mercury. The ACI fabric filter systems are more expensive but also more effective when a higher percentage of mercury must be removed. In the Clear Skies 3-P case, less than six gigawatts of ACI fabric filter systems are expected to be used (Figure 19). However, in the Clear Skies 3-P case without the mercury safety valve, over 52 gigawatts of ACI fabric filter systems are projected to be added.

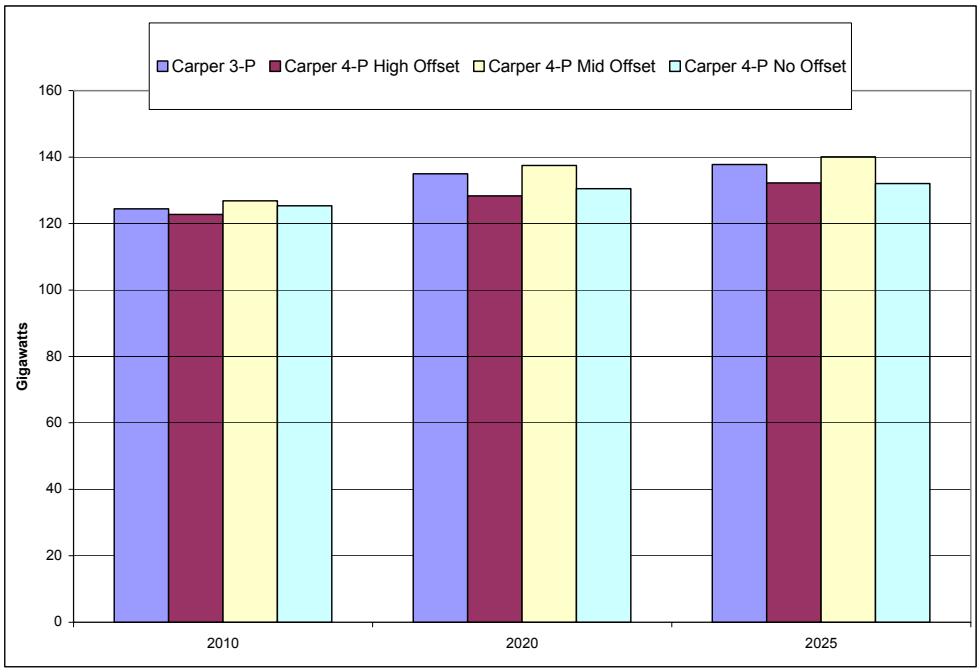
Figure 19. Cumulative Supplemental Fabric Filters Added for Mercury Removal in Clear Skies Cases, 2001 to Selected Dates



Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

Because of the requirement that all coal plants remove at least 70 percent of the mercury in the coal that they use and the tighter mercury caps in S. 843, ACI fabric filter systems are expected to be the key compliance strategy for reducing mercury emissions in the Carper 3-P and 4-P cases. By 2025 between 132 gigawatts and 140 gigawatts of capacity are projected to add ACI fabric filter systems in the Carper 3-P and 4-P cases (Figure 20).

Figure 20. Cumulative Supplemental Fabric Filters Additions for Mercury Removal in Carper Cases, 2001 to Selected Dates



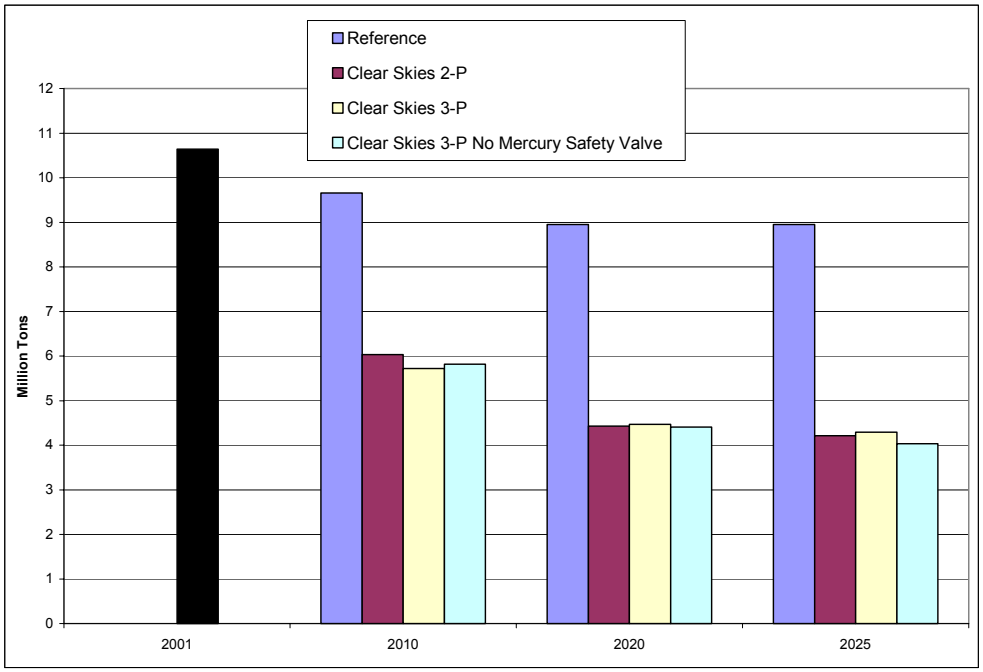
Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Emissions and Allowance Prices

Sulfur Dioxide

As might be expected, the respective allowance prices are projected to increase as the emissions caps are tightened. For example, under Clear Skies, national SO_2 emissions are projected to decline from approximately 10.6 million tons in 2001 to between 4.0 and 4.3 million tons in 2025 in the 2-P and 3-P cases (Figure 21). The differences in 2025 reflect slight differences in emissions banking patterns in the three cases. Note that because of emission banking, SO_2 emissions are not expected to reach the 3-million-ton target specified for 2018, even by 2025.

Figure 21. National SO_2 Emissions in Clear Skies Cases

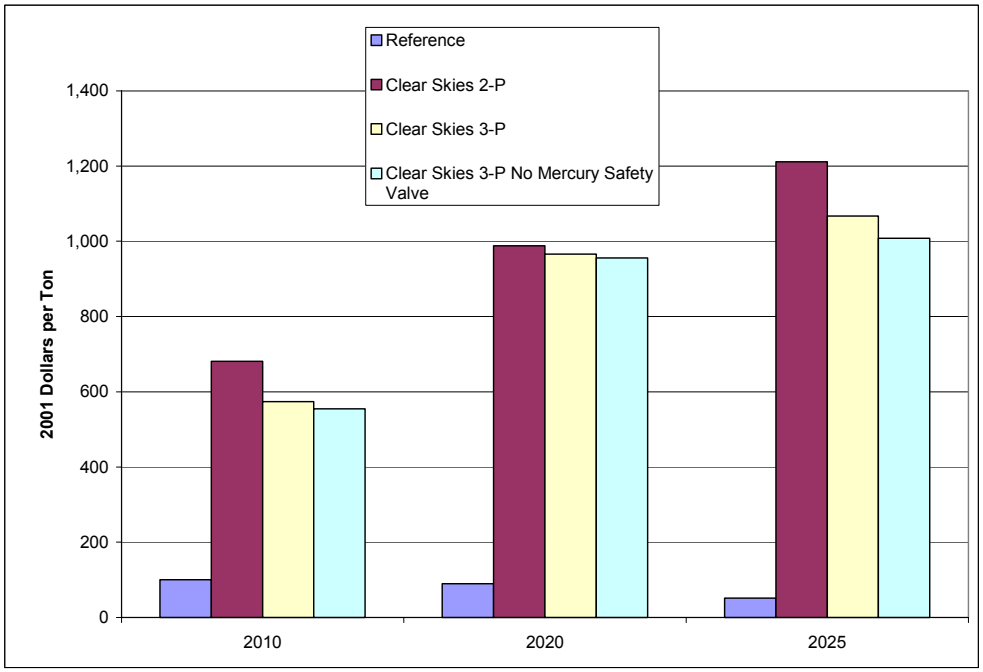


Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

SO_2 allowance prices under Clear Skies are projected to range from $554 per ton to $681 per ton in 2010 and from $1008 per ton to $1211 per ton in 2025 (Figure 22). Because actions taken to reduce mercury emissions can also reduce SO_2 emissions, SO_2 allowance prices are projected to be lower in the Clear Skies 3-P cases. That is, in the Clear Skies 2-P case, SO_2 scrubbers are added to reduce SO_2, while in the Clear Skies 3-P cases they are added to reduce both SO_2 and mercury.

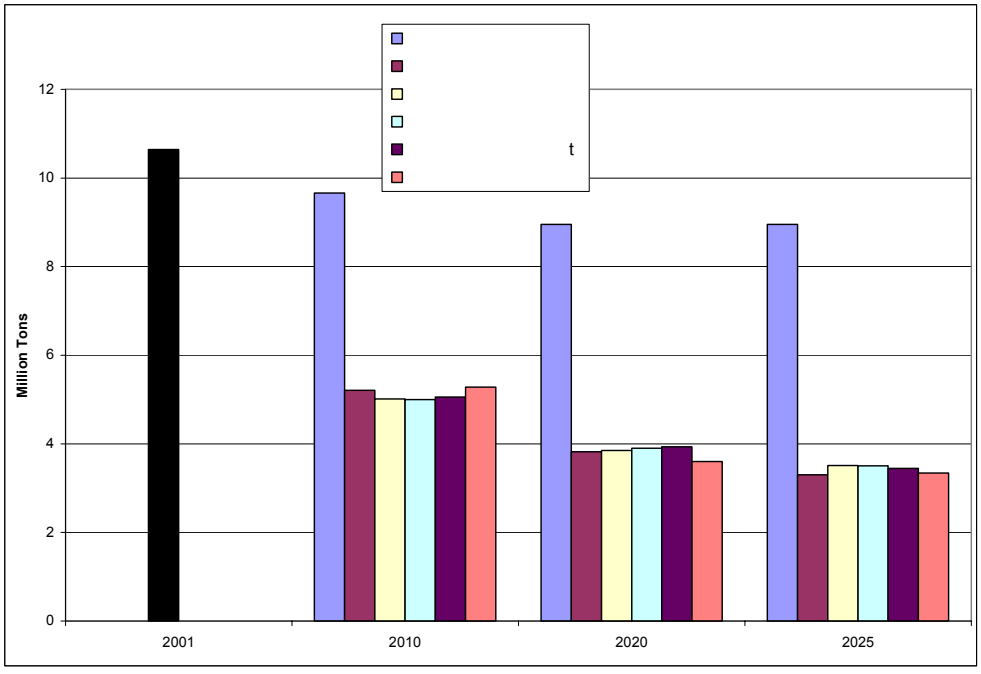
The pattern of SO_2 emissions and allowance prices is similar in the Carper 2-P and 3-P cases, though projected allowance prices are higher due to the lower emissions limits. In the Carper 2-P and 3-P cases, national SO_2 emissions are projected to decline from approximately 10.6 million tons in 2001 to between 3.3 million tons and 3.5 million tons in 2025 in the 2-P and 3-P cases (Figure 23). Again, the differences in 2025 reflect slight differences in emissions banking patterns in the two cases. Also, as is projected to occur under Clear Skies, because of emission banking, SO_2 emissions are not expected to reach the 2.25-million-ton target specified for 2016, even by 2025.

Figure 22. SO_2 Allowance Prices in Clear Skies Cases



Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

Figure 23. SO_2 Emissions in the Carper Cases



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

SO_2 allowance prices in the Carper 2-P and 3-P cases are projected to range from $877 per ton to $1160 per ton in 2010 and from $1454 per ton to $1680 per ton in 2025, much higher than in the comparable Clear Skies cases (Figure 24). Again, because actions taken to reduce mercury emissions can also reduce SO_2 emissions, SO_2 allowance prices are projected to be lower in the Carper 3-P case than in the Carper 2-P case. Generally, in the Carper 4-P cases, SO_2 allowance prices are lower than in the Carper 2-P case, especially in the Carper 4-P No Offset case where much lower projected coal use makes meeting the SO_2 target easier. In the Carper 4-P High Offset and Carper 4-P Mid Offset cases, SO_2 allowances prices are higher than in the Carper 3-P cases because the CO_2 allowance price reduces the additions of new relatively clean coal plants which would have displaced some of the generation from older coal plants. In other words, without the newer, cleaner coal plants, power generators must take higher-cost actions at older plants.

Figure 24. SO_2 Allowance Prices in the Carper Cases

Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Nitrogen Oxides

In the Clear Skies and Carper 2-P and 3-P cases, NO_x emissions are projected to fall from just over 5 million tons in 2000 to the 1.7 million ton target by 2020. In the Carper 4-P cases, particularly the Carper 4-P Mid and No Offset cases, NO_x emissions in the later years are actually projected to fall under the 1.7 million ton target as the use of older coal plants declines.

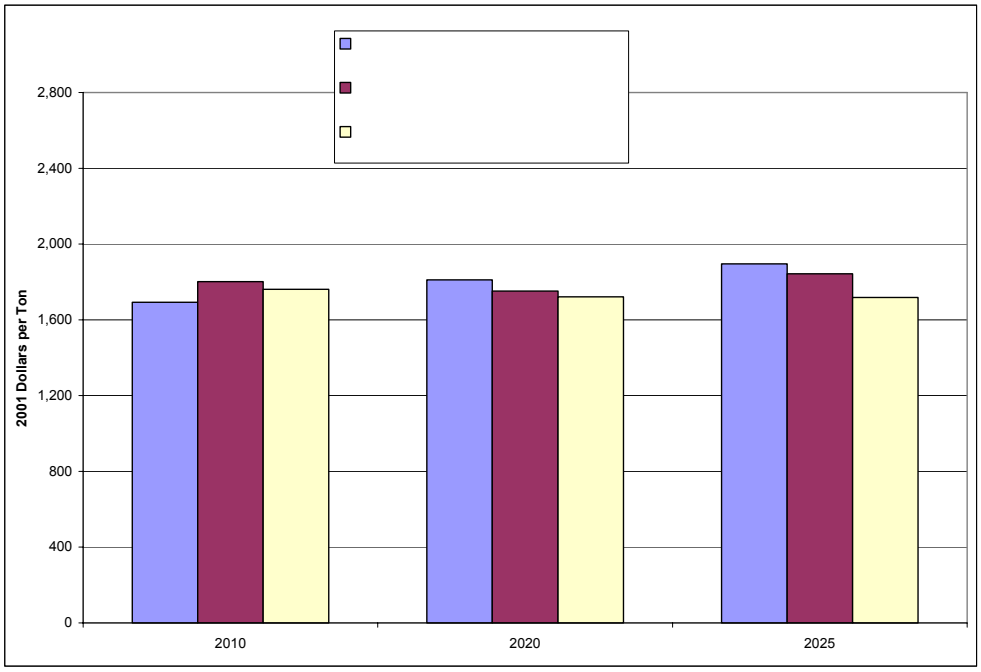
NO_x allowance prices under Clear Skies are projected to be higher in the East than in the West (Figures 25 and 26). Generally, eastern region NO_x allowance prices under Clear Skies are expected to be in the $2400 per ton to $2600 per ton range across all years. In contrast, western region NO_x allowance prices under Clear Skies are expected to be in the $1700 per ton to $1900 per ton range. NO_x allowance prices in the West are lower because the western region NO_x emissions cap does not require plants to reduce their emission rates as much as in the East. As was discussed with SO_2 allowance prices, NO_x allowance prices are expected to be lower in the Clear Skies 3-P cases than in the 2-P case, because efforts to reduce mercury emissions also contribute to reducing NO_x emissions.

NO_x allowances prices in the Carper 2-P and 3-P cases are expected to be similar to those projected in the comparable Clear Skies cases. For example in 2020, NO_x allowance prices in the Carper 2-P and 3-P cases range from $1935 per ton to $2237 per ton, roughly in the middle of the eastern and western region projections for Clear Skies. NO_x allowance prices in the Carper 4-P cases are projected to be lower, especially in the case without offsets. In this case, NO_x allowance prices are projected to fall to zero in the later years of the projections because of the reduced use of existing coal plants.

Figure 25. Eastern NO_x Allowance Prices in Clear Skies Cases

Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

Figure 26. Western NO_x Allowance Prices in Clear Skies Cases

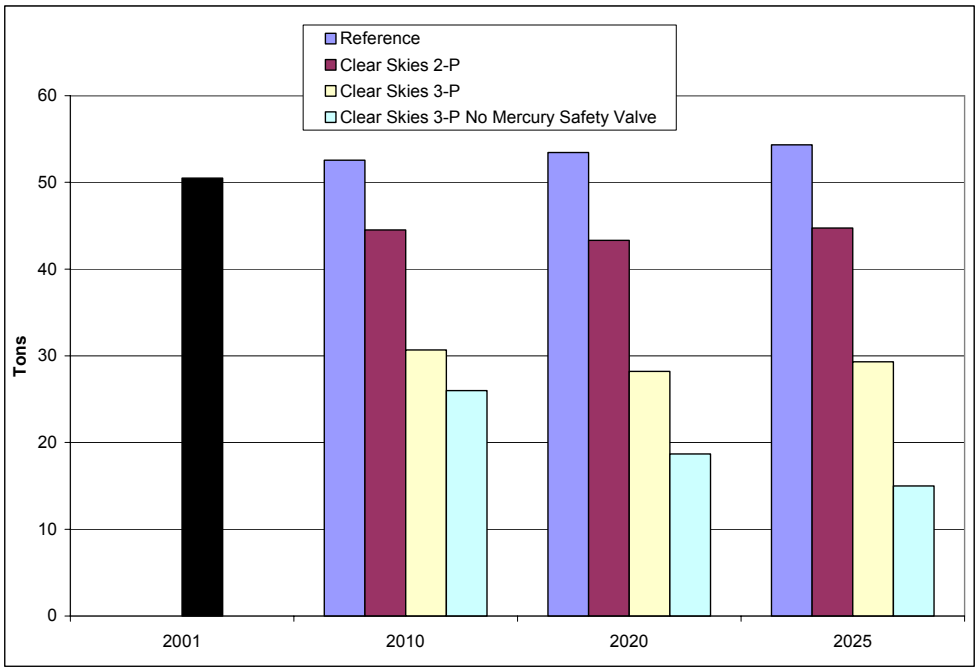


Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

Mercury

Mercury emissions are projected to be below the Reference case level in all of the Clear Skies cases, even in the 2-P case that does not have a mercury emissions cap (Figure 27). In the Reference case, mercury emissions are expected to increase to approximately 53 tons in 2010 as existing coal plants are used more intensively. However, in the Clear Skies 2-P case, 2010 mercury emissions are projected to be only 45 tons because equipment added to reduce NO_x and SO_2 emissions also reduces mercury emissions. In the Clear Skies 3-P case, mercury emissions are not projected to reach the 2010 or 2018 cap levels because of the mercury safety valve. In 2010 they are expected to be 31 tons, while in 2025 they are 29 tons.

Figure 27. Mercury Emissions in the Clear Skies Cases



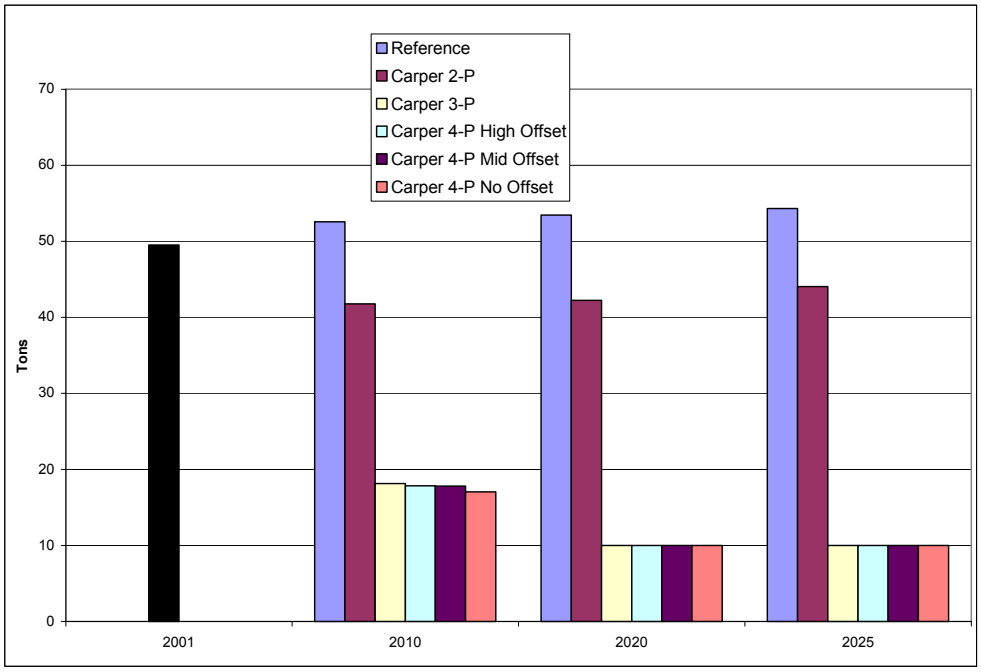
Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

In the Carper 2-P and 3-P cases, the pattern of mercury emissions is similar though lower because of the tighter mercury and SO_2 emissions caps. For example, in the Carper 2-P case, mercury emissions are projected to be 42 tons in 2010, much lower than the 53 tons projected in the Reference case (Figure 28). As in the Clear Skies 2-P case, equipment added to reduce NO_x and SO_2 emissions in this case also reduces mercury emissions. In the Carper 3-P and 4-P cases, the requirement that all plants remove a minimum of 70 percent of the mercury in the coal they use drives mercury emissions to between 17 tons and 18 tons in 2010, well below the 24-ton cap.[14]

In the Clear Skies 3-P case, mercury allowance prices are expected to be limited by the $35,000-per-pound safety valve (Figure 29). When the safety valve is removed, the mercury allowance price is projected rise from approximately $49,000 per pound in 2010 to $68,000 per pound in 2020 and $120,000 per pound in 2025.

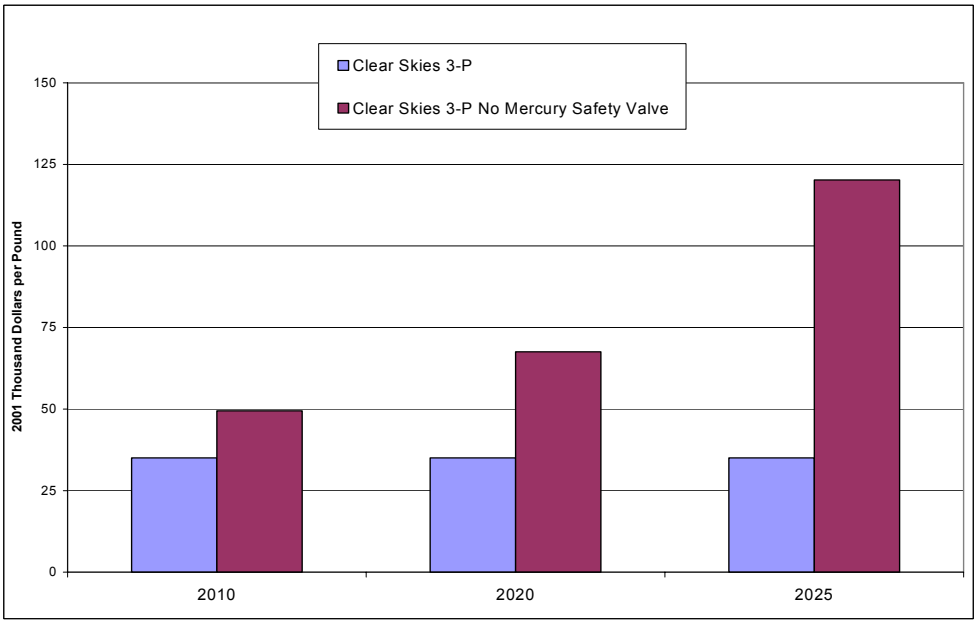
[14] The Carper bill requires that all coal facilities either remove a minimum percentage (50 percent between 2009 and 2012, and 70-percent in 2013 and later) of the mercury in the coal burned or meet an output-based rate to be set by the EPA Administrator. The 70-percent minimum removal is assumed for 2009 and beyond in this analysis. In a test case assuming a 50-percent removal requirement, mercury allowance prices between 2009 and 2012 were slightly greater than zero in the first three years. In other words, the 50-percent requirement did not quite reduce mercury emissions to the 24-ton cap between 2009 and 2012.

Figure 28. Mercury Emissions in the Carper Cases



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

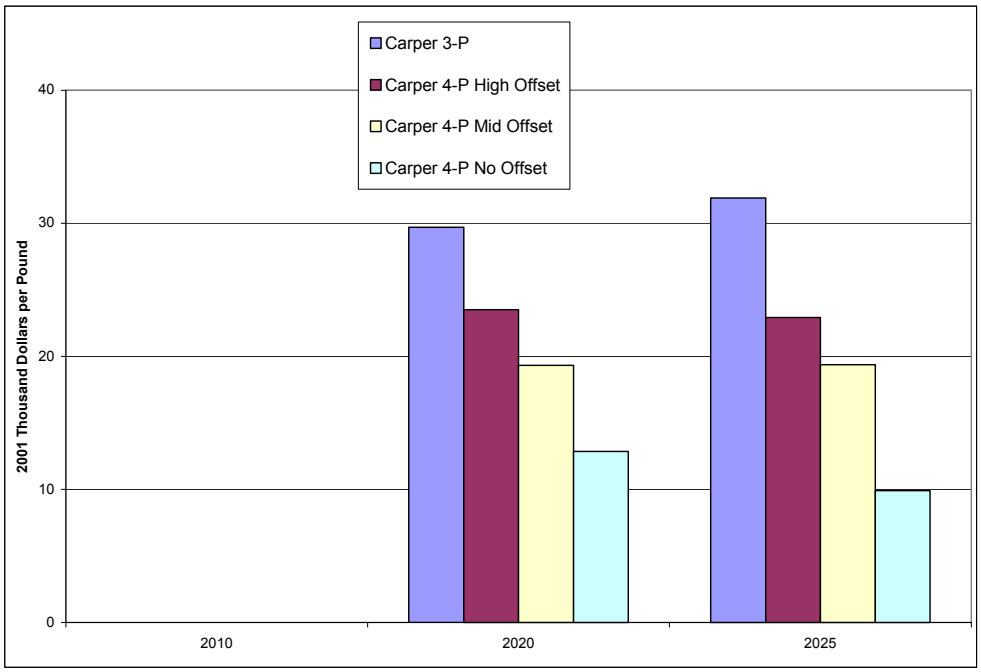
Figure 29. Mercury Allowance Prices in the Clear Skies Cases



Source: National Energy Modeling System, imcs3pws.d080503a, and imcs3pns.d080503a.

In the Carper 3-P and 4-P cases, mercury allowance prices in 2010 are projected to be zero because the 70-percent minimum removal requirement leads to mercury emissions that are below the 24-ton emissions cap. Positive mercury allowance prices are projected for 2013 and beyond when the mercury emissions cap falls to 10 tons (Figure 30). However, the mercury allowance prices are projected to be much lower than under Clear Skies because of the actions taken by plants to comply with the 70-percent removal requirement. For example, in the Carper 3-P case, the mercury allowance price in 2020 is projected to be nearly $30,000 per pound even though the emissions cap is 5 tons lower than the Clear Skies cap.

Figure 30. Mercury Allowance Prices in the Carper Cases



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

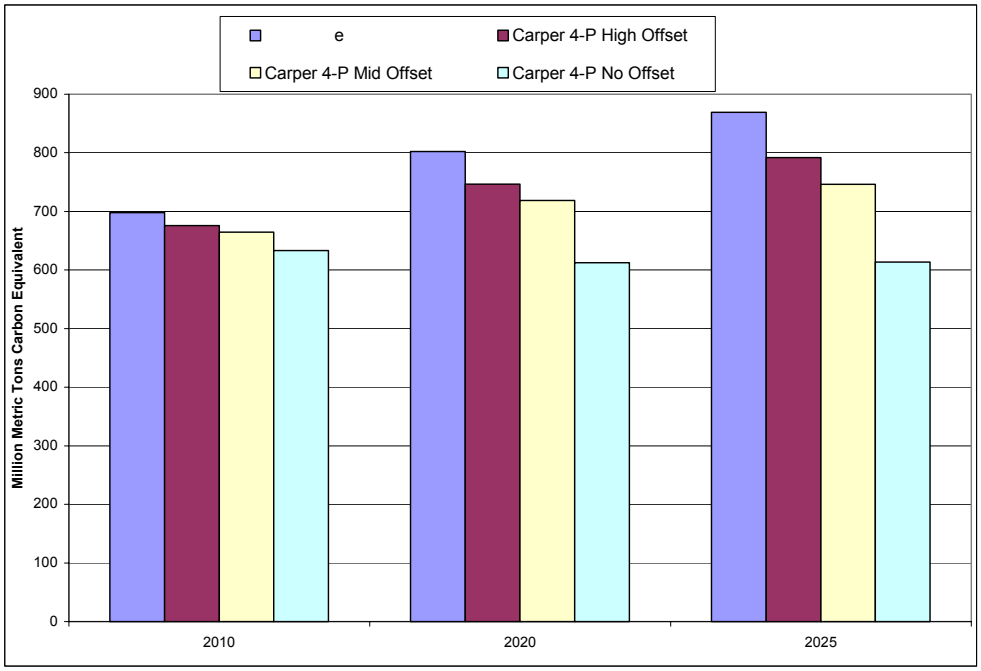
Carbon Dioxide

The small shift from coal to natural gas generation under Clear Skies is projected to result in a slight decline in CO_2 emissions. In 2020 CO_2 emissions in the 2-P and 3-P Clear Skies cases are projected to be between 24 million metric tons carbon equivalent (3 percent) and 36 million metric tons carbon equivalent (4 percent), respectively, below the Reference case level, but more than 154 million metric tons above the final CO_2 emissions cap set in the Carper bill.

The projected change in CO_2 emissions in the Carper 2-P and 3-P cases is similar to the change in the comparable Clear Skies cases. In the Carper 4-P cases, the change in CO_2 emissions varies, depending on the availability and cost of offsets (Figure 31). In the Carper 4-P High Offset case, power companies are projected to rely primarily on offsets

rather than direct emissions reductions to meet the CO_2 cap. CO_2 emissions in the power sector in that case are projected to remain 134 million metric tons carbon equivalent above the target level in 2020. Across the three Carper 4-P cases, offsets are projected to account for between 0 percent and 71 percent of the reductions needed to comply with the CO_2 cap in 2020.

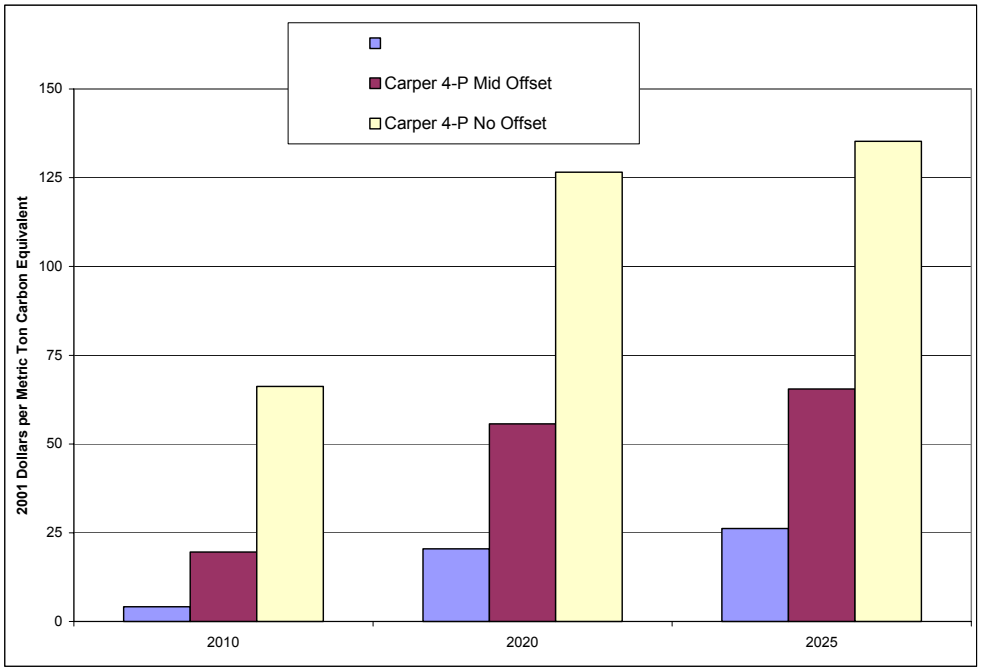
Figure 31. CO_2 Emissions in the Carper 4-P Cases



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

CO_2 allowance prices are also projected to vary significantly across the Carper 4-P cases (Figure 32). In 2010, CO_2 allowance prices are projected to range from $4 to $66 per metric ton carbon equivalent, while in 2025 the range widens to between $26 and $135 per metric ton carbon equivalent. The higher values represent projected allowance costs if the power sector were required to reduce its emissions to the target level without relying on offsets.

Figure 32. CO_2 Allowance Prices in the Carper 4-P Cases



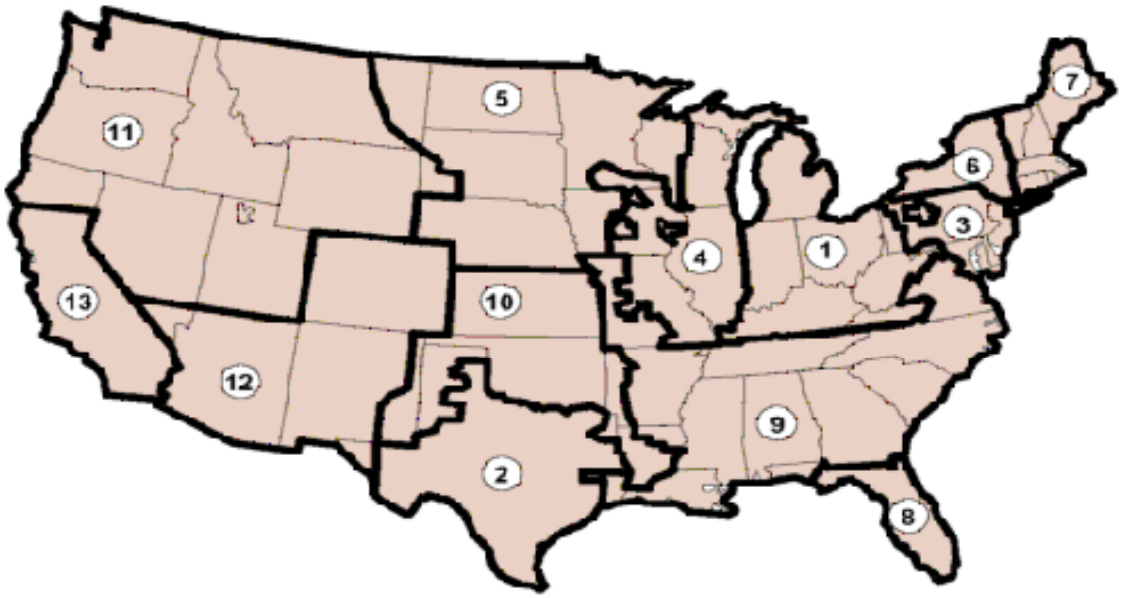
Source: National Energy Modeling System, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Regional Emissions

The NEMS model reports regional results for the electric power sector based on reliability council regions and subregions (Figure 33). Under Clear Skies, NO_x, SO_2, and Hg emissions are projected to fall in all regions of the country, but the largest changes are in regions where coal supplies a large share of the generation (Figures 34 through 36).[15] Large heavily coal-based regions such as ECAR and SERC are projected to show the largest reductions in NO_x, SO_2, and Hg emissions under Clear Skies. The regional decline in mercury emissions is dampened by the safety valve in the Clear Skies 3-P, but reductions are still projected to occur in all regions of the country.

[15] For a map of the electricity regions in the National Energy Modeling System see http://www.eia.doe.gov/oiaf/aeo/supplement/supmap.pdf.

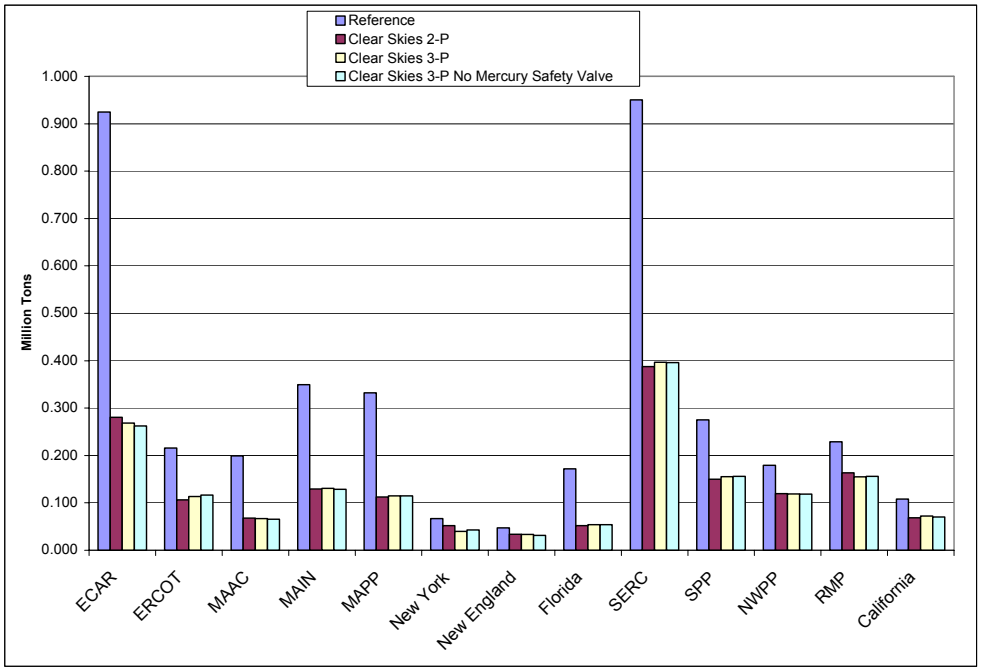
Figure 33. Electricity Regions



1. East Central Area Reliability Coordination Agreement (ECAR)
2. Electric Reliability Council of Texas (ERCOT)
3. Mid-Atlantic Area Council (MAAC)
4. Mid-America Interconnected Network (MAIN)
5. Mid-Continent Area Power Pool (MAPP)
6. New York
7. New England
8. Florida
9. Southeastern Electric Reliability Council (SERC)
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWPP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RMP)
13. California

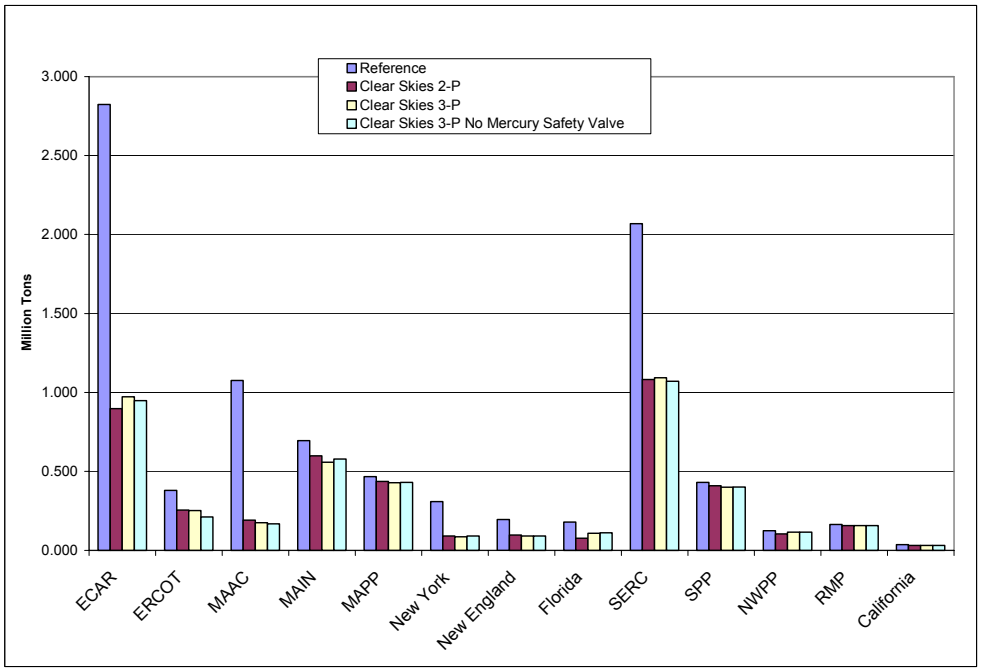
Source: Office of Integrated Analysis and Forecasting

Figure 34. Regional NO_x Emissions in Clear Skies Cases, 2020



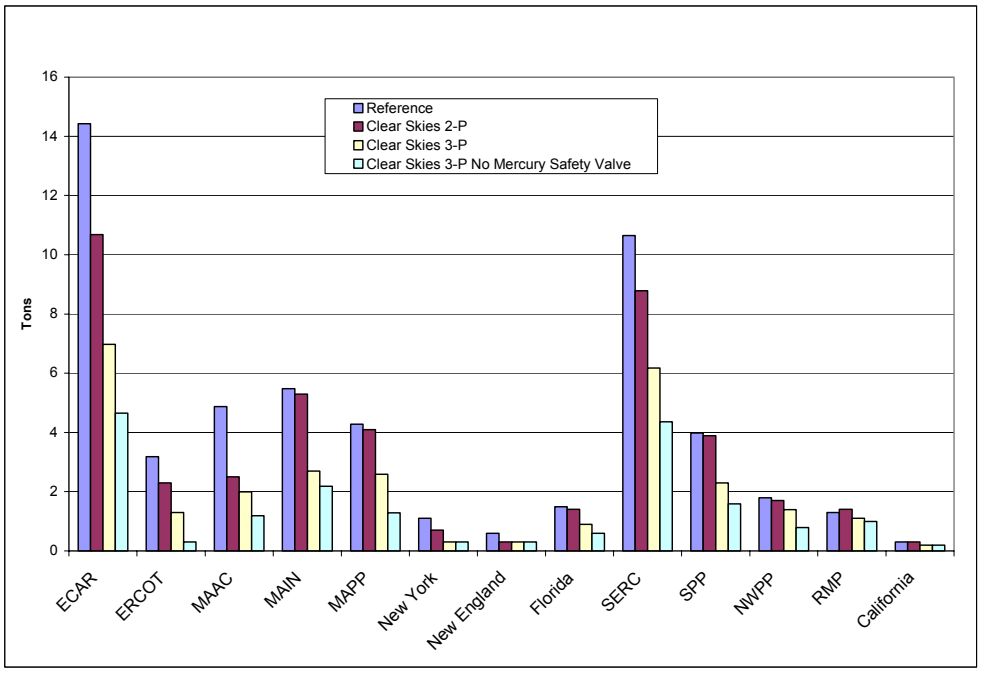
Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

Figure 35. Regional SO_2 Emissions in Clear Skies Cases, 2020



Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

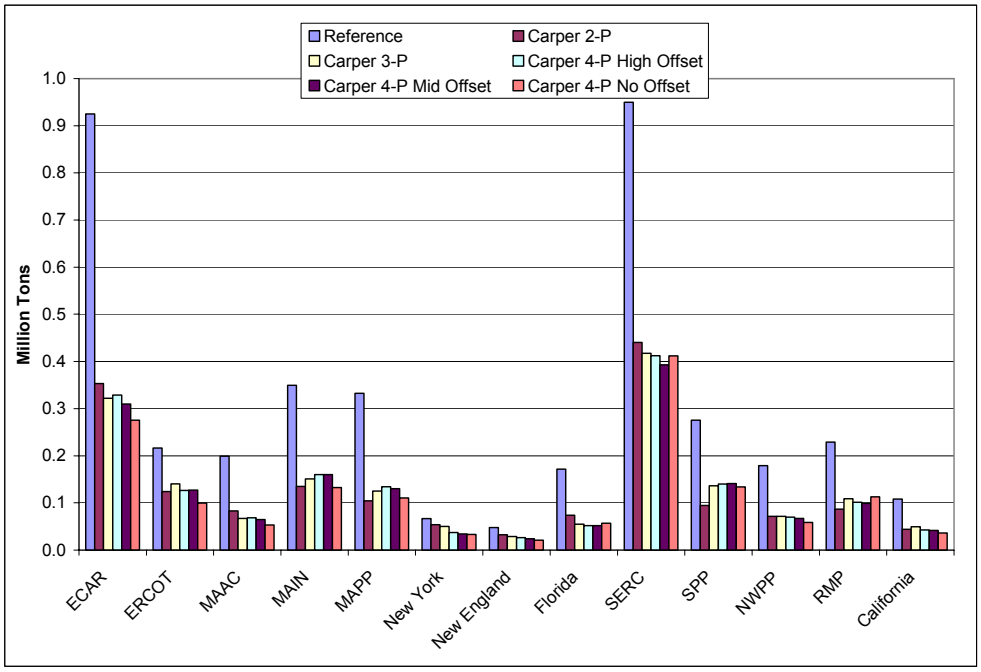
Figure 36. Regional Mercury Emissions in Clear Skies Cases, 2020



Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

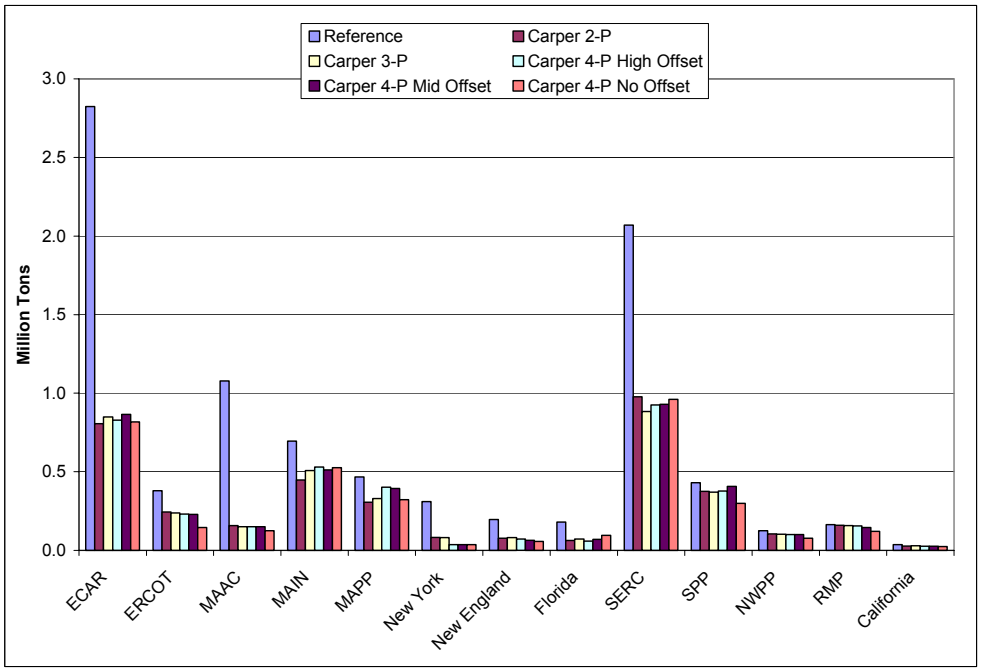
In the Carper cases NO_x, SO_2, and Hg emissions are also projected to fall in all regions of the country. Because of the tighter emissions caps and earlier reduction schedule the regional emissions in 2020 are generally a little lower than under Clear Skies. As under Clear Skies, the largest changes are in regions where coal supplies a large share of the generation (Figures 37 through 39) specifically ECAR and SERC.

Figure 37. Regional NO_x Emissions in the Carper Cases, 2020



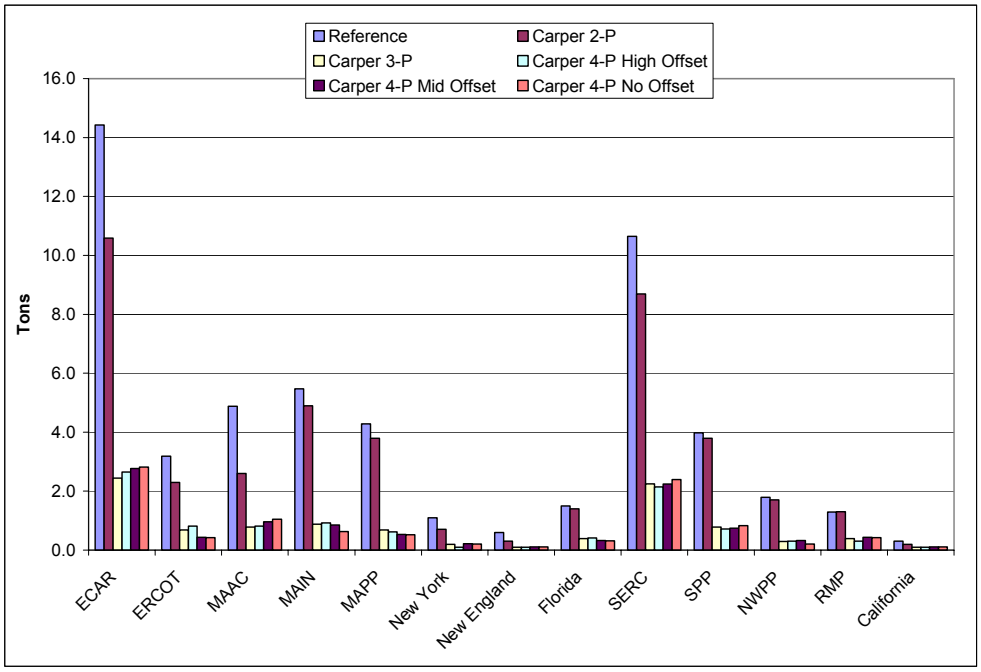
Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Figure 38. Regional SO_2 Emissions in the Carper Cases, 2020



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Figure 39. Regional Mercury Emissions in the Carper Cases, 2020

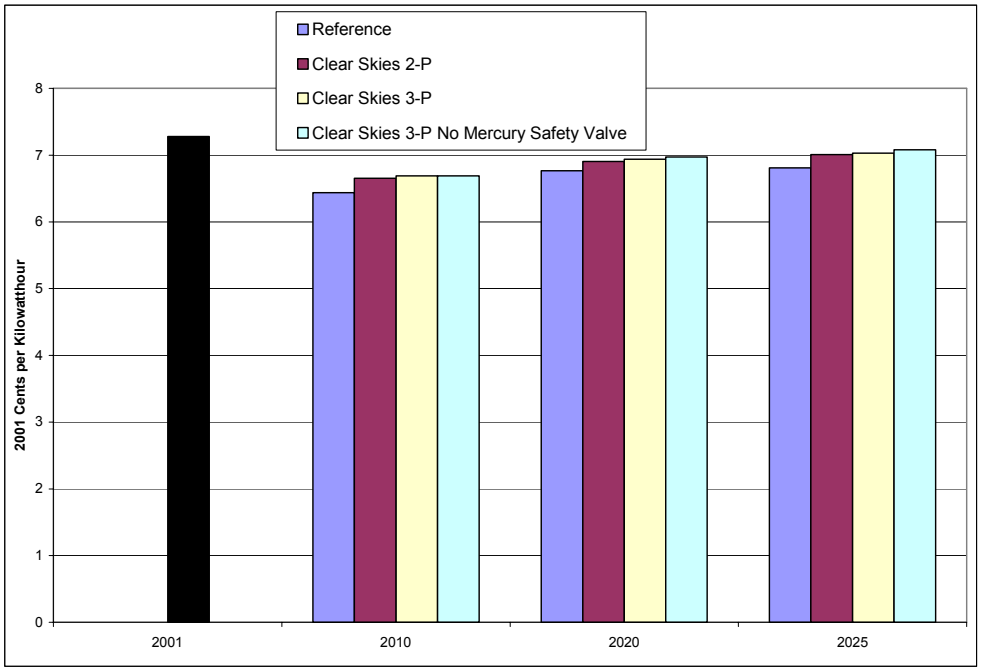


Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Electricity Prices and Costs

The Clear Skies and Carper bills are projected to lead to higher electricity prices. Relatively speaking, the changes expected in the 2-P and 3-P cases are small, while those in the Carper 4-P cases are larger, particularly if offsets are limited. In the Clear Skies cases, electricity prices in 2010 are projected to be between 3.4 percent and 4.0 percent higher than in the Reference case (Figure 40). In terms of the Nation's total electricity bill, these changes amount to an increase of between $7 billion and $9 billion (2.7 percent to 3.3 percent). In 2025, the projected changes in electricity prices are similar, ranging from 2.9 percent and 4.0 percent higher than in the Reference case, while the Nation's total electricity bill is between $7 billion and $10 billion higher than in the Reference case (2.1 percent to 2.8 percent).

Figure 40. Electricity Prices in the Clear Skies Cases

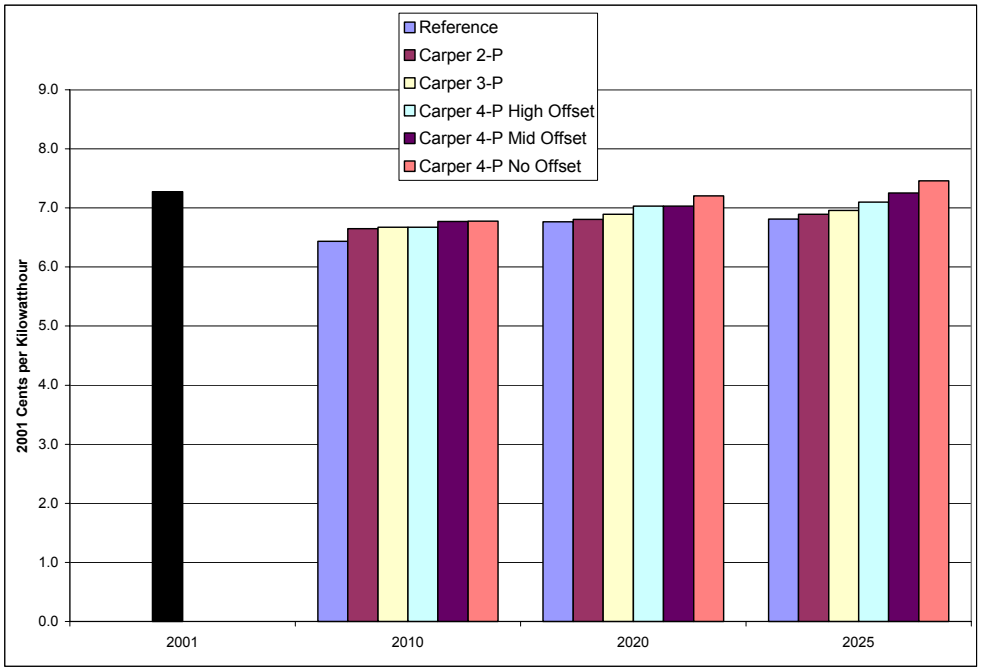


Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

In the Carper 2-P and 3-P cases, electricity prices in 2010 are projected to be between 3.3 percent and 3.7 percent higher than in the Reference case (Figure 41). Relative to those in the comparable Clear Skies cases, the smaller percentage changes in the Carper 2-P and 3-P cases are due to the effects of the GPS approach used to allocate allowances. In terms of the Nation's total electricity bill, these changes amount to an increase of between $7 billion and $8 billion in 2010. In 2025, the projected changes in electricity prices range from 1.2 percent to 2.1 percent higher than in the Reference case, while the Nation's total electricity bill is between $2 billion and $5 billion higher than in the Reference case.

The potential electricity price and bill changes are projected to be larger in the Carper 4-P cases, but they are very sensitive to assumptions about offset availability and costs. Electricity prices in 2010 are projected to be between 3.7 percent and 5.3 percent higher in the Carper 4-P cases than in the Reference case. In terms of the Nation's total electricity bill, these changes also amount to an increase of between $8 billion and $11 billion. In 2025 the projected change in electricity prices in the Carper 4-P cases range from 4.2 percent to 9.5 percent higher than in the Reference case, while the Nation's electricity bill is between $11 billion and $24 billion higher than in the Reference case.

Figure 41. Electricity Prices in the Carper Cases

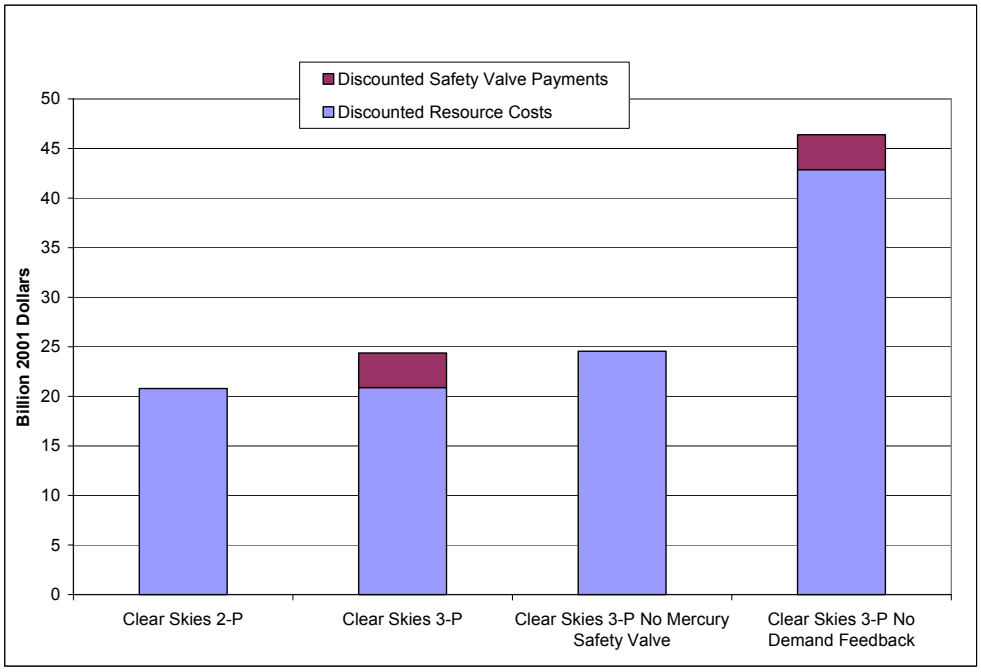


Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Relative to the Reference case, power companies are expected to incur greater costs to comply with the provisions of Clear Skies. These costs, often referred to as resource costs, include fuel, operations and maintenance, and capital expenditures. In addition, when the mercury safety valve is exercised under Clear Skies, power companies will be paying the government for additional allowances. Relative to the Reference case, resource costs and mercury safety valve payments over the 2005 to 2025 time period are projected to be $20.8 billion higher in the Clear Skies 2-P case and $24.4 billion higher in the Clear Skies 3-P case (Figure 42).[16] These increases are less than 2 percent of the Reference case resource costs. Adding the mercury cap to the NO_x and SO_2 caps increases costs in 2010 by slightly less than $700 million. The changes in costs are dampened somewhat by consumers' responses to the higher electricity prices projected in the Clear Skies cases.[17] If consumer electricity consumption did not fall in response to the higher electricity prices, the power industry could incur greater costs to comply. In a case without consumer demand response (labeled Clear Skies 3-P No Demand Feedback in Figure 42), the increase in discounted resource costs and mercury safety valve payments over the 2005 to 2025 time period is projected to be $46.4 billion.

[16] These values represent discounted expenditures using a 7-percent discount rate.
[17] Because the National Energy Modeling System is an integrated model of supply and demand interactions, higher energy prices lead to lower consumption.

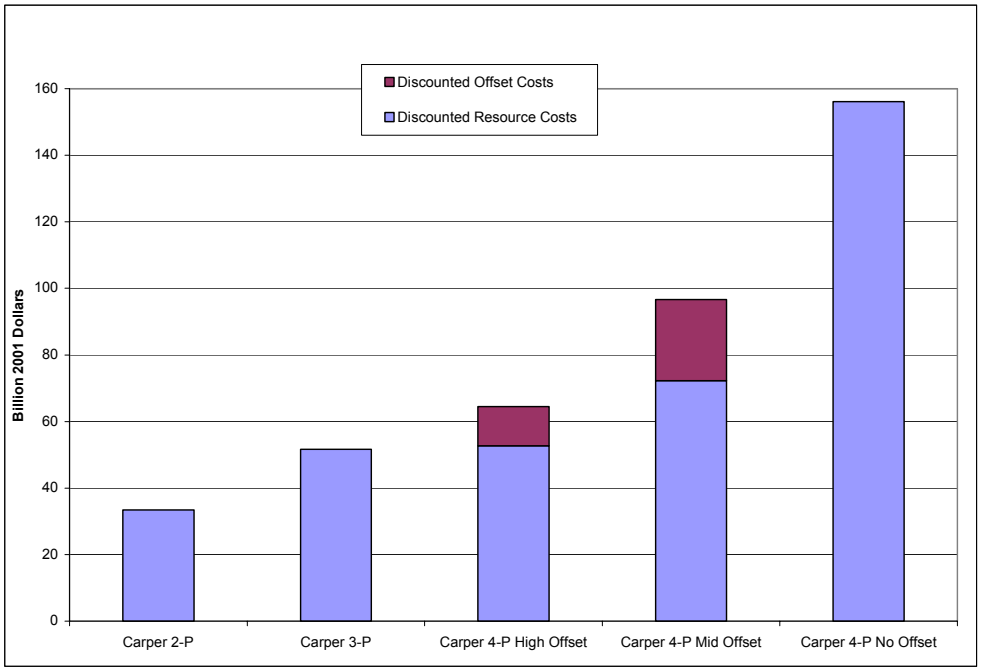
Figure 42. Resource Costs and Safety Valve Payments in Clear Skies Cases



Source: National Energy Modeling System, imbase.d080503a, imcs2p.d081103a, imcs3pws.d080503a, and imcs3pns.d080503a.

In the Carper 2-P and 3-P cases, the change in discounted resource costs over the 2005 to 2025 time period is projected to range from $33.4 to $51.7 billion (Figure 43). The higher costs relative to the comparable Clear Skies cases result from the more stringent emissions caps, the lack of a mercury safety valve, the minimum mercury removal requirement, and the GPS emission allowance allocation approach used that reduces output substitution (i.e., there is a smaller electricity price impact so consumers do not lower their demands as much as they otherwise would). In the Carper 4-P cases, power companies will not only face higher electricity production costs, they also will be paying for offsets. The combination of higher discounted resource and offset costs over the 2005 to 2025 time period ranges between $64.5 billion and $156.1 billion in the Carper 4-P cases.

Figure 43. Resource Costs and Offset Payments in Carper Cases



Source: National Energy Modeling System, imbase.d080503a, imca2p.d080503a, imca3p.d080503a, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

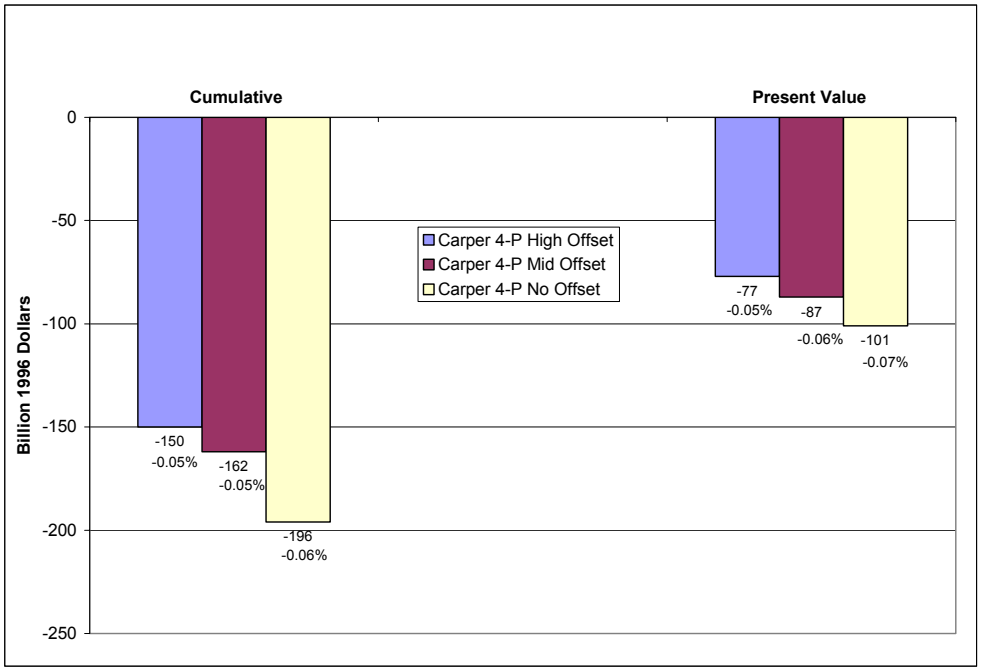
Macroeconomic Impacts

Given the relatively small price impacts projected in the Clear Skies and Carper 2-P and 3-P cases, the overall macroeconomic impacts are expected to be small. The impacts are somewhat larger in the Carper 4-P cases. These policies will affect the economy through a complex set of interactions between elements of aggregate supply and demand, in conjunction with monetary and fiscal policy decisions. Households would be faced with higher prices for energy and the need to adjust spending patterns. Nominal energy expenditures would rise, taking a larger share of the family budget for goods and service consumption and leaving less for savings. Higher prices for energy would cause consumers to try to reduce spending not only on energy, but on other goods as well. Thus, changes in energy prices would tend to alter both saving and spending streams. Energy services also represent a key input in the production of final goods and services. As energy prices increase, the costs of production rise, placing upward pressure on the nominal prices of all intermediate goods and final goods and services in the economy, with widespread impacts on spending across many markets. The ultimate effect will depend on opportunities for substitution away from higher-cost energy to other goods and services and the effectiveness of compensatory fiscal and monetary policy.

This section considers the impacts associated with three of the Carper cases: Carper 4-P High Offset, Carper 4-P Mid Offset, and Carper 4-P No Offset. These cases consider alternative availability of offsets, which will affect the ultimate cost of allowances. Figure 44 below shows both the cumulative sum of the actual GDP loss over the period

from 2004 through 2025 and also the present value of this loss using a discount rate of 7 percent. The Carper 4-P High Offset case allows for the greatest use of lower-priced offsets and indicates that the impact on the economy using both measures is the lowest of the three cases, with a $150-billion cumulative loss of actual GDP and a present value loss of $77 billion. As the use of offsets is diminished, the aggregate cost to the economy rises. In the Carper 4-P No Offset case, the cumulative loss rises to $196 billion, with a present value loss of $101 billion. The Carper 4-P Mid Offset case falls between these two cases. While these losses may seem substantial, in terms of the cumulative sum (or present value) of actual GDP output over the same period in the Reference case, the impacts average between 0.05 and 0.07 percent of the aggregate output of the economy between 2004 and 2025.

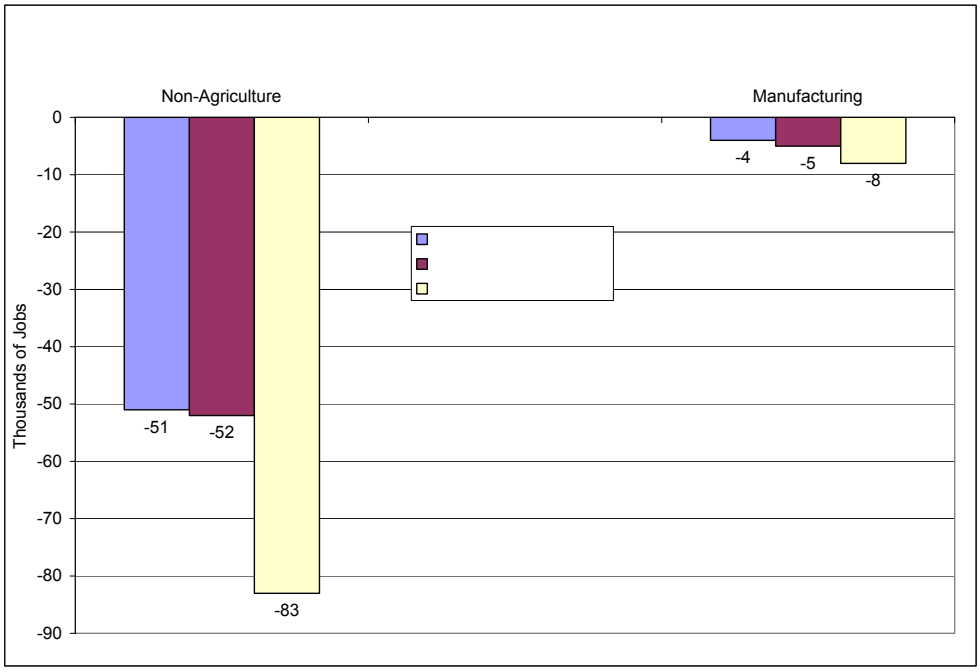
Figure 44. Present Value and Cumulative GDP Loss in Carper 4-P Cases, 2004-2025



Source: National Energy Modeling System, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

These losses in economic output have an impact on employment in the aggregate economy (Figure 45). The average loss in jobs over the 2004 through 2025 period ranges between 51 thousand jobs in the Carper 4-P High Offset case to a maximum loss of 83 thousand jobs in the Carper 4-P No Offset case. For manufacturing, the loss ranges between 4 thousand and 8 thousand jobs. As with the loss in economic output, these losses are small, less than 0.1 percent of the respective average total employment over the period.

Figure 45. Average Loss in Employment in the Carper 4-P Cases



Source: National Energy Modeling System, imca4p.d080703a, imca4plo.d08703b, and imca4pno.d080703b.

Comparison to EPA Clear Skies Analysis

While there are differences, the EIA and EPA analyses of the impacts of Clear Skies are similar in many respects. In terms of overall annual costs, EPA finds that Clear Skies would cost $4.3 billion in 2010, $4.4 billion in 2015, and $6.3 billion in 2020. EIA finds similar values, $4.2 billion in 2010, $5.0 billion in 2015 and $5.9 billion in 2020.[18] The results for emissions control retrofits are also similar. For example, EPA finds that Clear Skies will lead to approximately 200 gigawatts of coal capacity having SCRs to remove NO_x by 2020, while EIA finds 179 gigawatts of capacity will have them. EPA finds that just over 200 gigawatts of coal capacity will have SO_2 scrubbers by 2020, while EIA finds that 171 gigawatts will have them. For supplemental fabric filters and activated carbon to remove mercury, EPA finds that only a few gigawatts of capacity will add them by 2020 while EIA finds that nearly 6 gigawatts will have them. In addition, both EPA and EIA find that the mercury safety valve in Clear Skies will be triggered and that mercury emissions will remain above the emissions cap throughout the projections, reaching 22 tons in EPA's analysis and 28 tons in EIA's analysis in 2020.

The key differences between the EPA and EIA analysis are in the amount of mercury that will be removed by the co-benefits associated with NO_x and SO_2 removal and allowance

[18] The values cited here for EIA are from the Clear Skies 3-P case without demand feedback. This is done because the EPA modeling system does not endogenously address consumers' responses to higher electricity prices.

prices for NO_x in the East and West. EPA projects that mercury emissions will fall from about 50 tons of emissions in 2001to 45 tons in 2010 in its Reference case, and 34 tons in a Clear Skies case without the mercury emissions cap. On the other hand, EIA projects that, because of increasing coal use, mercury emissions will increase to 53 tons by 2010 in its Reference case and 45 tons in a Clear Skies case without the mercury emissions cap. Differences in relative electricity demand growth, relative fuel prices, and coal mix (i.e., bituminous, subbituminous, and lignite) appear to be the key drivers in this divergence. EIA's results show stronger electricity demand growth, higher natural gas prices, and greater use of coal, particularly western subbituminous coal, than EPA's results.

EIA projects higher NO_x allowance prices than does EPA. For example, EIA projects that NO_x allowance prices in the East will be over $2400 per ton in 2020 while EPA projects they will be $1500 per ton. The key factor in this divergence is different assumptions about the cost of new SCRs. EPA assumes that it will cost approximately $65 per kilowatt to retrofit an SCR to a 500-megawatt plant, while EIA assumes it will cost just under $100 per kilowatt.[19] EPA's costs are in line with equipment vendor estimates, but actual realized costs for recently added units have shown much higher costs. Department of Energy experts believe that the costs for a 500-megawatt unit are actually closer to $120 per kilowatt than to $100 per kilowatt.

Clear Skies Act and Carper Bill Under High Gas Prices

Natural gas use is becoming increasingly more important to the electric power industry in meeting their generation needs and achieving environmental compliance. Over the past few years, natural gas price volatility has increased. Because of the uncertainty in natural gas prices, the impact of higher gas prices was analyzed for the Clear Skies 3-P Mercury Safety Valve, Carper 4-P High Offset, and Carper 4-P No Offset cases. The difference in natural gas wellhead prices between the Reference Case Gas Price[20] and their respective High Gas Price[21] scenarios grows over time with natural gas prices in the High Gas Price scenarios exceeding natural gas prices in the Reference Case Gas Price scenarios by 6-7 percent in 2005 and 26 – 31 percent by 2025[22].

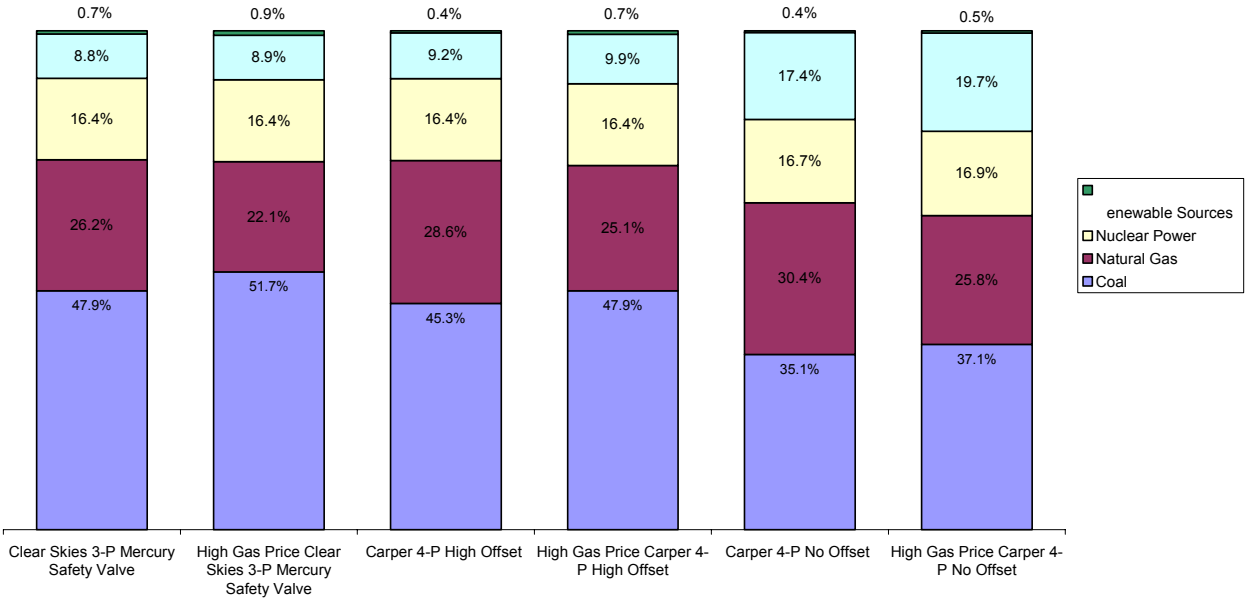
Generation, Fuel Use, and Capability

Higher natural gas prices lead to lower natural gas fuel use and increased coal and renewable fuels use across scenarios. The largest impacts occur in the Carper bill scenarios because they rely more heavily on natural gas as a compliance strategy to meet the more restrictive SOx, NOx, and Hg emissions limits as well as the additional limit on

[19] Power Engineering, May 2003, *Uniqueness of SCR Retrofits Translates into Broad Cost Variations*.
[20] The High Gas Price scenarios are: Clear Skies 3-P Mercury Safety Valve High Gas Price, Carper 4-P High Offset High Gas Price, and Carper 4-P No Offset High Gas Price.
[21] The Reference Case Gas Price scenarios are: Clear Skies 3-P Mercury Safety Valve, Carper 4-P High Offset, and Carper 4-P No Offset.
[22] The High Gas Price scenarios were constructed by assuming a 25-percent reduction in U.S. and Canadian resources, a 25-percent reduction in the rate of technological progress, a lengthening of the time needed to complete the Alaska natural gas pipeline from 7 to 10 years, and restricting new domestic LNG facilities to Florida and the Gulf of Mexico.

carbon dioxide emissions. The figure below illustrates the impact of higher natural gas prices on the Carper 4-P High Offsets scenario, a scenario that relies relatively more on natural gas generation to achieve compliance than some of the other scenarios examined. As illustrated in the Figure 46 below, higher natural gas prices result in a 12-percent decline in gas-fired generation and offsetting increases in coal-fired and renewable generation.

Figure 46. Generation Fuel Shares by Scenario, 2020.



Source: National Energy Modeling System, imcs3pws.d080503a, cs3ws_hgp.d082203a, mca4p.d080703a, ca4mo_hgp.d082003a, imca4pno.d080703a, ca4pno_hgp.d082603a.

The impacts on natural gas fuel use and capacity additions are similar to the impact on natural gas-fired generation. Higher natural gas prices result in less natural gas fuel use across scenarios, as generating fuel share is lost to coal-fired, renewable, and petroleum-fired generation. The higher natural gas prices also affect capacity expansion choices in the power sector resulting in less natural gas-fired capacity and more coal-fired and renewable capacity. By 2020, cumulative unplanned capacity additions of natural gas-fired generation are 17 to 26 gigawatts less in the High Gas Price scenarios than in the Reference Case Gas Price scenarios. The natural gas-fired capacity displaced in the High Gas Price scenarios is replaced with coal-fired and renewable capacity.

Electricity Prices and Resource Costs

Both electricity prices and resource costs are higher in the High Gas Price scenarios than in the Reference Case Gas Price scenarios due to the assumed higher natural gas prices. In the High Gas Price scenarios, electricity prices are 2.2 percent to 4.0 percent higher

than in the Reference Case Gas Price scenarios in 2020. The smallest increase (2.2 percent) occurs in the Carper 4-P High Offsets High Gas Price scenario and the largest increase (4.2 percent) occurs in the Carper 4-P No Offset High Gas Price scenario. Typically, the larger the share of natural gas-fired generation the larger the impact of higher natural gas prices; however, the percentage price increase in the Carper 4-P High Offsets High Gas Price scenario is less than the percentage price increase in the Clear Skies 3-P High Gas Price scenario due to the generation performance standard contained in the Carper bill that results in a smaller electricity price increase than in the Clear Skies bill. Resource Costs are higher in the High Gas Price scenarios than in the Reference Case Gas Price scenarios. The resource costs increases are in proportion to their reliance on natural gas-fired generation and the higher fuel prices and the more capital-intensive coal-fired and renewable generation capacity, replacing natural gas-fired capacity. like coal-fired and renewable technologies. Resource costs increase of 1.3 percent in the Clear Skies 3-P Mercury Safety Valve High Gas Price scenario, 1.6 percent in the Carper 4-P High Offsets High Gas Price scenario and 1.7 percent in the Carper 4-P No Offsets High Gas Price scenario.

Additional Context for this Report

Modeling Considerations

The Reference Case used in this report includes final regulatory action under existing laws. However, consistent with standard EIA practice requiring policy neutrality in baseline projections, it does not include pending or proposed actions, such as the maximum achievable control technology (MACT) standards for mercury emissions from power plants. The implementation of such actions could affect emissions, generator costs, and electricity prices during the projection period even if there is no new legislation.

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 and the availability and cost of greenhouse gas offsets.

In recent years, substantial information has been gathered on the factors influencing mercury emissions at existing plants, i.e., the 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, 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 roll 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. In this analysis, SCRs are not assumed to enhance mercury removal at plants using subbituminous or lignite coals. The outcome of this research will be important because power plants are expected to invest in SCRs to meet the NO_x emissions caps in the Clear Skies and Carper bills. If these investments also contribute to removing mercury emissions, they could lower the incremental costs of meeting the mercury emissions caps.

Another area of uncertainty is the cost and performance of mercury removal systems. Supplemental fabric filter systems using activated carbon injection, 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 have not been performed. This analysis assumes these systems will be equally effective on the lower rank coals and be able to achieve removal rates as high as 90 percent. However, experts at the Department of Energy believe that the lower chlorine content typically found in subbituminous and lignite coals may limit the ability of ACI fabric filter systems to remove mercury from them. There is also uncertainty on the cost of these systems. Based on information from the National Energy Technology Laboratory, this analysis assumes these systems will typically cost just over $50 per kilowatt of capacity on a 500-megawatt unit. Experts at the Department of energy have indicated that the test units from which these costs were developed may have been undersized, presenting unacceptable maintenance problems. Their current estimate of the cost of an appropriately sized system is nearly $80 per kilowatt for a 500-megawatt unit, a 60-percent increase from earlier estimates. Again, more research is needed to confirm these findings.

There is also uncertainty about the cost of SCR systems. In the 1990s various estimates typically put the costs of these systems at $70 to $90 per kilowatt of capacity.[23] However, many power companies are now installing these systems to comply with summer NO_x emission limits that take affect in 2004. Reported costs for these retrofits are higher than the previously estimated costs, ranging from $80 per kilowatt to $160 per kilowatt.[24] This analysis assumes that retrofitting a SCR on a 500-megawatt unit will cost just under $100 per kilowatt. This is within the range of the recent costs, but a higher cost may be justified if reported costs continue to exceed them.

The potential availability and cost of CO_2 offsets are also very uncertain. There is uncertainty in what offsets might actually cost and what rules and regulations the independent review board (IRB) called for in the Carper bill might establish for acceptable international trading programs and offset projects. The marginal abatement curves used here were developed by the EPA using engineering cost analysis. The curves suggest that there are many low cost – some actually with negative costs (i.e., a company could increase its profits by taking the modeled actions) – opportunities for reducing

[23] Power Engineering, May 2003, *Uniqueness of SCR Retrofits Translates into Broad Cost Variations*.
[24] Ibid

greenhouse gas emissions. More work is needed to determine whether these curves accurately reflect the costs faced by the various industries studied, especially those where the curves suggest a large number of profitable investments are being overlooked. While beyond the scope of this report, there is substantial debate about the existence of a large amount of "negative-cost" greenhouse gas reduction options.[25] These curves likely oversimplify the invention, innovation, and market diffusion process that new technologies generally follow and may understate the costs involved in achieving the reductions.

The IRB established in the Carper bill will have to establish measurement, verification, and enforcement procedures for acceptable international programs and offset projects. The procedures established will impact the availability and cost of offsets. For example, if the IRB requires strict measurement and verification procedures, many projects such as those in agriculture and forestry may find the costs of compliance make their projects uneconomical. The actual greenhouse gas savings from projects in these areas are difficult to measure and verify. On the other hand, the IRB could establish simple protocols for such projects, making it relatively easy to submit estimated savings and receive extra CO_2 allowances. However, in this case program regulators would never accurately know how much greenhouse gases were actually being reduced.

Scope of this Report

The analysis in this report, like other EIA analyses, focuses on the impact of the two bills under review on energy choices made in all energy-using 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 emissions reductions.

[25] For discussion of this topic see Jaffe, A.B., R.G. Newell and R.N. Stavins (1999), Energy-Efficient Technologies and Climate Change Policies: Issues and Evidence, Climate Issue Brief 19, Resources for the Future, Washington, DC, http://www.rff.org/issue_briefs/PDF_files/ccbrf19.pdf.

Appendix A

Requesting Letter

JAMES M. INHOFE, OKLAHOMA, CHAIRMAN

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

July 30, 2003

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

Dear Mr. Administrator:

Legislation affecting the regulation of environmental emissions from electric generators is of increasing interest to the Senate. As a result, I hereby request the Energy Information Administration to undertake analyses of S.843, The Clean Air Planning Act of 2003, introduced by Senator Thomas Carper, and S.485, Clear Skies Act of 2003, introduced by myself.

These bills would require significant reductions of emissions of sulfur dioxides (SO_x), nitrogen oxides (NO_x), and Mercury (Hg). In addition, the Clean Air Planning Act of 2003 requires reductions of carbon dioxide emissions (CO_2).

In fulfilling this request, please use the latest National Energy Modeling System (NEMS) reference case developed to analyze the S. 139, the Climate Stewardship Act of 2003 in order to provide a basis of comparison to what might be expected without future legislation. I am particularly interested that the following components be included in the analysis:

1. The reductions in SOx, NOx, Hg, and CO2 required both nationally and regionally;
2. The marginal cost of reducing SOx, NOx, Hg, and CO2 (provide regional information where appropriate);
3. The amount of emissions control equipment and activated carbon injection required to comply with the legislation;
4. The total resource cost (in present value terms) for each Bill;
5. The impact on energy production (coal, natural, oil, renewable, etc.) and energy prices;
6. The impact on residential electric and natural gas consumers;
7. The impact on macroeconomic activity and coal employment, resulting from passage of each Bill;
8. The loss in electric industry revenues projected for each of the Bills.

Please evaluate the following additional scenarios. With respect to the Clear Skies Act of 2003 evaluate two additional scenarios that achieve the following:

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- Eliminate the safety valve component of the Hg provisions and
- Eliminate the Hg provisions.

With respect to the Clean Air Planning Act of 2003, evaluate two additional scenarios that achieve the following:

- Eliminate the CO2 provisions and
- Eliminate both Hg provisions and the CO2 provisions.

Any further details of the analysis can be addressed with John Shanahan at 202-224-8072. I would appreciate it if you would provide the analysis of the Clear Skies Act of 2003 by August 22nd and the Clean Air Planning Act of 2003 by August 25th. Thank you in advance for your cooperation. I believe these analyses will be essential to ensuring an informed debate on the multi-emission issue.

Sincerely,

U.S. Senator James M Inhofe
Chairman
Committee on Environment and Public Works

Appendix B Tables:

Reference, Clear Skies 2P, Clear Skies 3P with Safety

Table B1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Production										
Crude Oil and Lease Condensate	12.29	11.93	11.94	11.94	11.50	11.50	11.50	11.29	11.26	11.29
Natural Gas Plant Liquids	2.65	3.14	3.15	3.17	3.59	3.60	3.59	3.71	3.74	3.75
Dry Natural Gas	19.97	22.26	22.37	22.45	26.18	26.27	26.18	27.15	27.34	27.43
Coal	23.97	25.56	25.09	24.96	27.53	26.39	26.13	29.48	27.75	27.63
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[1]	5.32	7.28	7.37	7.37	8.36	8.52	8.53	8.81	8.97	8.96
Other[2]	0.57	0.85	0.85	0.85	0.79	0.79	0.79	0.80	0.80	0.80
Total	**72.80**	**79.24**	**78.99**	**78.95**	**86.21**	**85.32**	**84.97**	**89.49**	**88.11**	**88.12**
Imports										
Crude Oil[3]	20.26	25.07	25.02	25.03	27.60	27.59	27.61	28.55	28.47	28.46
Petroleum Products[4]	5.04	6.34	6.21	6.17	11.68	11.52	11.48	14.86	14.80	14.77
Natural Gas	4.18	5.54	5.60	5.63	7.37	7.96	8.12	8.61	9.35	9.29
Other Imports[5]	0.73	0.94	0.97	0.98	0.99	1.00	1.01	0.95	0.96	0.96
Total	**30.21**	**37.89**	**37.79**	**37.81**	**47.63**	**48.08**	**48.21**	**52.96**	**53.58**	**53.48**
Exports										
Petroleum[6]	2.01	2.25	2.25	2.25	2.34	2.36	2.34	2.42	2.44	2.43
Natural Gas	0.37	0.56	0.56	0.56	0.37	0.36	0.36	0.36	0.35	0.35
Coal	1.27	0.87	0.87	0.85	0.74	0.74	0.74	0.61	0.69	0.62
Total	**3.64**	**3.67**	**3.69**	**3.66**	**3.46**	**3.47**	**3.44**	**3.39**	**3.48**	**3.40**
Discrepancy[7]	**2.08**	**0.22**	**0.22**	**0.26**	**0.22**	**0.23**	**0.18**	**0.20**	**0.22**	**0.29**
Consumption										
Petroleum Products[8]	38.46	44.48	44.31	44.30	52.20	52.04	52.02	56.18	56.03	56.02
Natural Gas	23.26	27.61	27.77	27.88	33.56	34.25	34.32	35.79	36.72	36.76
Coal	22.02	25.32	24.85	24.70	27.58	26.41	26.22	29.75	27.94	27.81
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[1]	5.32	7.28	7.37	7.37	8.36	8.53	8.53	8.81	8.97	8.96
Other[9]	0.21	0.33	0.36	0.37	0.21	0.22	0.22	0.08	0.09	0.09
Total	**97.29**	**113.24**	**112.87**	**112.84**	**130.17**	**129.70**	**129.56**	**138.87**	**138.00**	**137.90**
Net Imports - Petroleum	**23.29**	**29.16**	**28.98**	**28.95**	**36.93**	**36.76**	**36.75**	**40.99**	**40.84**	**40.80**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.99	23.99	25.48	25.48	25.48	26.57	26.57	26.57
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.42	3.43	3.45	3.67	3.66	3.67	3.97	4.10	4.14
Coal Minemouth Price (dollars per ton)	17.59	15.06	14.67	15.54	14.23	13.29	14.42	14.22	13.06	13.66
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.7	6.7	6.8	6.9	6.9	6.8	7.0	7.0

[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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.84	0.84	0.81	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.46	0.46	0.46	0.46	0.47	0.46
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.36	1.36	1.36	1.33	1.33	1.33
Natural Gas	4.94	5.63	5.63	5.63	6.11	6.11	6.10	6.38	6.35	6.35
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.41	0.41	0.41	0.40	0.40	0.40
Electricity	4.10	4.93	4.89	4.88	5.59	5.55	5.54	5.94	5.89	5.88
Delivered Energy	**10.94**	**12.44**	**12.40**	**12.39**	**13.48**	**13.43**	**13.42**	**14.07**	**13.98**	**13.98**
Electricity Related Losses	9.15	10.41	10.30	10.29	11.13	10.96	10.94	11.51	11.24	11.22
Total	**20.08**	**22.85**	**22.70**	**22.69**	**24.61**	**24.40**	**24.36**	**25.58**	**25.23**	**25.19**
Commercial										
Distillate Fuel	0.46	0.51	0.51	0.51	0.52	0.53	0.53	0.52	0.53	0.53
Residual Fuel	0.09	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.70	0.72	0.73	0.73	0.72	0.73	0.73
Natural Gas	3.33	3.74	3.73	3.73	4.24	4.23	4.23	4.51	4.49	4.49
Coal	0.09	0.10	0.10	0.10	0.10	0.11	0.10	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	5.01	4.98	4.98	6.15	6.11	6.10	6.76	6.71	6.71
Delivered Energy	**8.32**	**9.65**	**9.62**	**9.62**	**11.32**	**11.28**	**11.27**	**12.21**	**12.15**	**12.14**
Electricity Related Losses	9.12	10.58	10.50	10.49	12.26	12.08	12.05	13.10	12.82	12.79
Total	**17.44**	**20.23**	**20.11**	**20.11**	**23.58**	**23.37**	**23.32**	**25.31**	**24.97**	**24.93**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.21	1.21	1.36	1.36	1.35	1.44	1.44	1.44
Liquefied Petroleum Gas	2.10	2.55	2.55	2.55	3.05	3.05	3.06	3.29	3.29	3.29
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	0.23	0.19	0.19	0.19	0.19	0.19	0.19	0.20	0.20	0.20
Motor Gasoline[2]	0.15	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.27	4.26	4.26	4.45	4.47	4.48	4.57	4.58	4.58
Petroleum Subtotal	8.79	9.82	9.80	9.80	10.93	10.96	10.97	11.52	11.52	11.52
Natural Gas	7.74	9.07	9.09	9.10	10.50	10.57	10.56	11.28	11.35	11.37
Lease and Plant Fuel[6]	1.20	1.38	1.38	1.39	1.65	1.66	1.65	1.73	1.74	1.74
Natural Gas Subtotal	8.94	10.45	10.47	10.48	12.15	12.22	12.21	13.01	13.09	13.12
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.42	1.45	1.45	1.45	1.51	1.51	1.51	1.54	1.54	1.54
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.16	2.23	2.22	2.22	2.22	2.22	2.21	2.22	2.22	2.22
Renewable Energy[7]	1.82	2.22	2.22	2.22	2.77	2.77	2.77	3.05	3.05	3.05
Electricity	3.39	3.96	3.94	3.94	4.64	4.62	4.61	4.99	4.96	4.94
Delivered Energy	**25.10**	**28.68**	**28.66**	**28.66**	**32.71**	**32.79**	**32.78**	**34.79**	**34.83**	**34.85**
Electricity Related Losses	7.57	8.37	8.32	8.31	9.25	9.13	9.11	9.66	9.46	9.42
Total	**32.67**	**37.05**	**36.98**	**36.97**	**41.96**	**41.92**	**41.89**	**44.45**	**44.29**	**44.27**

Table B2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Transportation										
Distillate Fuel[8]	5.44	7.09	7.08	7.07	8.68	8.68	8.67	9.55	9.54	9.53
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.09	5.67	5.66	5.67
Motor Gasoline[2]	16.26	19.81	19.79	19.79	23.57	23.56	23.56	25.48	25.47	25.47
Residual Fuel	0.84	0.83	0.83	0.83	0.86	0.86	0.85	0.87	0.87	0.87
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.07	0.07	0.07	0.09	0.09	0.08
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.97	31.94	31.93	38.57	38.56	38.56	41.97	41.94	41.94
Pipeline Fuel Natural Gas	0.63	0.78	0.79	0.79	0.98	0.98	0.97	1.03	1.04	1.04
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.14
Delivered Energy	**26.94**	**32.91**	**32.88**	**32.88**	**39.78**	**39.77**	**39.76**	**43.26**	**43.24**	**43.23**
Electricity Related Losses	0.17	0.20	0.20	0.20	0.24	0.24	0.24	0.27	0.27	0.27
Total	**27.10**	**33.11**	**33.08**	**33.07**	**40.02**	**40.01**	**40.00**	**43.53**	**43.51**	**43.50**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.73	9.72	9.71	11.40	11.40	11.39	12.32	12.32	12.31
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.09	5.67	5.66	5.67
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.68	3.68	3.69	3.94	3.93	3.94
Motor Gasoline[2]	16.46	20.01	19.99	19.99	23.79	23.78	23.78	25.71	25.70	25.70
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	1.15	1.06	1.06	1.06	1.10	1.10	1.10	1.12	1.12	1.12
Other Petroleum[12]	4.24	4.51	4.49	4.49	4.73	4.75	4.76	4.87	4.87	4.87
Petroleum Subtotal	37.21	43.96	43.90	43.90	51.59	51.61	51.62	55.54	55.52	55.52
Natural Gas	16.02	18.50	18.51	18.52	20.95	21.01	20.98	22.28	22.30	22.33
Lease and Plant Fuel Plant[6]	1.20	1.38	1.38	1.39	1.65	1.66	1.65	1.73	1.74	1.74
Pipeline Natural Gas	0.63	0.78	0.79	0.79	0.98	0.98	0.97	1.03	1.04	1.04
Natural Gas Subtotal	17.86	20.66	20.68	20.70	23.58	23.64	23.61	25.04	25.08	25.11
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.53	1.56	1.56	1.56	1.63	1.63	1.63	1.66	1.66	1.66
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.27	2.34	2.33	2.33	2.33	2.34	2.33	2.34	2.34	2.34
Renewable Energy[13]	2.31	2.74	2.73	2.73	3.29	3.29	3.29	3.57	3.56	3.56
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	13.99	13.90	13.89	16.50	16.40	16.37	17.84	17.70	17.67
Delivered Energy	**71.29**	**83.68**	**83.55**	**83.55**	**97.29**	**97.28**	**97.22**	**104.33**	**104.21**	**104.21**
Electricity Related Losses	26.00	29.56	29.32	29.29	32.88	32.42	32.35	34.54	33.79	33.69
Total	**97.29**	**113.24**	**112.87**	**112.84**	**130.17**	**129.70**	**129.56**	**138.87**	**138.00**	**137.90**
Electric Power[14]										
Distillate Fuel	0.17	0.10	0.10	0.10	0.11	0.13	0.10	0.18	0.21	0.21
Residual Fuel	1.08	0.41	0.31	0.30	0.50	0.30	0.30	0.47	0.30	0.30
Petroleum Subtotal	1.25	0.51	0.41	0.40	0.61	0.43	0.40	0.64	0.51	0.51
Natural Gas	5.40	6.95	7.08	7.19	9.98	10.61	10.71	10.75	11.63	11.64
Steam Coal	19.75	22.99	22.51	22.37	25.25	24.08	23.89	27.41	25.60	25.47
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[15]	3.01	4.55	4.64	4.64	5.08	5.24	5.24	5.25	5.41	5.40
Electricity Imports	0.21	0.33	0.36	0.37	0.21	0.22	0.22	0.08	0.09	0.09
Total	**37.65**	**43.55**	**43.22**	**43.19**	**49.38**	**48.82**	**48.71**	**52.38**	**51.49**	**51.37**

Table B2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Total Energy Consumption										
Distillate Fuel	8.10	9.84	9.82	9.81	11.51	11.53	11.49	12.49	12.53	12.51
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.09	5.67	5.66	5.67
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.68	3.68	3.69	3.94	3.93	3.94
Motor Gasoline[2]	16.46	20.01	19.99	19.99	23.79	23.78	23.78	25.71	25.70	25.70
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	2.23	1.47	1.36	1.36	1.60	1.40	1.40	1.58	1.41	1.42
Other Petroleum[12]	4.24	4.51	4.49	4.49	4.73	4.75	4.76	4.87	4.87	4.87
Petroleum Subtotal	38.46	44.48	44.31	44.30	52.20	52.04	52.02	56.18	56.03	56.02
Natural Gas	21.42	25.45	25.59	25.70	30.93	31.62	31.70	33.03	33.93	33.98
Lease and Plant Fuel[6]	1.20	1.38	1.38	1.39	1.65	1.66	1.65	1.73	1.74	1.74
Pipeline Natural Gas	0.63	0.78	0.79	0.79	0.98	0.98	0.97	1.03	1.04	1.04
Natural Gas Subtotal	23.26	27.61	27.77	27.88	33.56	34.25	34.32	35.79	36.72	36.76
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	21.28	24.55	24.08	23.93	26.88	25.71	25.51	29.07	27.27	27.13
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	22.02	25.32	24.85	24.70	27.58	26.41	26.22	29.75	27.94	27.81
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[16]	5.32	7.28	7.37	7.37	8.36	8.53	8.53	8.81	8.97	8.96
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.33	0.36	0.37	0.21	0.22	0.22	0.08	0.09	0.09
Total	**97.29**	**113.24**	**112.87**	**112.84**	**130.17**	**129.70**	**129.56**	**138.87**	**138.00**	**137.90**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.68	83.55	83.55	97.29	97.28	97.22	104.33	104.21	104.21
Total Energy Use	97.29	113.24	112.87	112.84	130.17	129.70	129.56	138.87	138.00	137.90
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12254	12238	12237	16448	16459	16456	18914	18913	18911
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.7	1790.0	1786.8	2080.2	2057.5	2051.4	2236.6	2202.3	2198.2

[1]Includes wood used for residential heating. See Table B18 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]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[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 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[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 2001 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: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B3. Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Residential	**15.80**	**14.02**	**14.30**	**14.36**	**14.67**	**14.86**	**14.90**	**14.99**	**15.34**	**15.38**
Primary Energy[1]	9.73	8.08	8.10	8.11	8.30	8.29	8.31	8.59	8.71	8.74
Petroleum Products[2]	10.85	10.02	10.02	10.02	10.92	10.91	10.92	11.23	11.22	11.22
Distillate Fuel	8.99	7.99	7.99	7.99	8.72	8.72	8.72	8.92	8.92	8.92
Liquefied Petroleum Gas	14.84	14.35	14.34	14.34	15.27	15.23	15.27	15.58	15.56	15.55
Natural Gas	9.41	7.60	7.62	7.64	7.73	7.72	7.74	8.05	8.20	8.24
Electricity	25.36	22.58	23.32	23.44	23.22	23.71	23.80	23.31	24.00	24.07
Commercial	**15.50**	**13.49**	**13.84**	**13.89**	**14.79**	**14.99**	**15.04**	**15.20**	**15.55**	**15.59**
Primary Energy[1]	7.81	6.45	6.47	6.48	6.75	6.74	6.75	7.07	7.19	7.22
Petroleum Products[2]	7.27	6.77	6.77	6.77	7.52	7.50	7.50	7.81	7.80	7.79
Distillate Fuel	6.40	5.66	5.67	5.67	6.46	6.46	6.46	6.75	6.75	6.74
Residual Fuel	3.46	4.01	4.00	4.00	4.24	4.21	4.21	4.40	4.37	4.37
Natural Gas	8.09	6.52	6.53	6.55	6.75	6.75	6.76	7.09	7.23	7.27
Electricity	23.27	19.88	20.55	20.65	21.42	21.83	21.93	21.62	22.19	22.24
Industrial[3]	**7.11**	**6.42**	**6.50**	**6.52**	**7.02**	**7.06**	**7.09**	**7.31**	**7.42**	**7.43**
Primary Energy	5.83	5.19	5.19	5.20	5.71	5.70	5.72	6.00	6.06	6.07
Petroleum Products[2]	7.72	7.07	7.07	7.07	7.83	7.82	7.85	8.15	8.16	8.14
Distillate Fuel	6.55	5.74	5.75	5.75	6.73	6.72	6.73	7.18	7.19	7.19
Liquefied Petroleum Gas	12.34	9.92	9.92	9.92	10.83	10.82	10.84	11.14	11.15	11.12
Residual Fuel	3.28	3.72	3.70	3.70	3.95	3.92	3.92	4.11	4.09	4.09
Natural Gas[4]	4.87	4.04	4.05	4.07	4.36	4.37	4.38	4.66	4.79	4.83
Metallurgical Coal	1.69	1.50	1.51	1.50	1.39	1.39	1.39	1.34	1.34	1.34
Steam Coal	1.46	1.38	1.37	1.39	1.31	1.27	1.29	1.29	1.24	1.26
Electricity	14.13	12.95	13.46	13.54	13.67	13.99	14.08	13.78	14.24	14.29
Transportation	**10.28**	**10.20**	**10.23**	**10.23**	**10.37**	**10.37**	**10.36**	**10.83**	**10.81**	**10.82**
Primary Energy	10.25	10.18	10.20	10.20	10.34	10.34	10.33	10.80	10.79	10.80
Petroleum Products[2]	10.25	10.18	10.20	10.20	10.35	10.34	10.34	10.81	10.79	10.80
Distillate Fuel[5]	10.05	10.19	10.19	10.19	10.27	10.25	10.22	10.67	10.62	10.64
Jet Fuel[6]	6.20	5.64	5.65	5.65	6.34	6.34	6.34	6.72	6.73	6.73
Motor Gasoline[7]	11.57	11.43	11.46	11.46	11.54	11.54	11.54	12.07	12.06	12.07
Residual Fuel	3.90	3.57	3.56	3.56	3.78	3.77	3.77	3.95	3.94	3.94
Liquefied Petroleum Gas[8]	16.93	15.52	15.50	15.49	16.01	15.97	16.01	16.04	16.07	15.95
Natural Gas[9]	7.65	7.22	7.24	7.26	7.71	7.71	7.73	8.11	8.27	8.30
Ethanol (E85)[10]	17.72	21.29	21.33	21.34	22.85	22.87	22.88	23.57	23.51	23.53
Electricity	21.87	19.18	19.76	19.87	18.72	19.07	19.15	18.11	18.67	18.74
Average End-Use Energy	**10.74**	**9.99**	**10.10**	**10.12**	**10.50**	**10.55**	**10.57**	**10.88**	**10.99**	**11.01**
Primary Energy	8.52	8.07	8.08	8.08	8.44	8.43	8.43	8.85	8.88	8.89
Electricity	21.33	18.86	19.51	19.61	19.83	20.23	20.33	19.96	20.54	20.60
Electric Power[11]										
Fossil Fuel Average	2.14	1.85	1.89	1.91	2.07	2.15	2.16	2.15	2.33	2.34
Petroleum Products	4.73	4.28	4.39	4.39	4.58	4.90	4.84	4.94	5.29	5.26
Distillate Fuel	6.20	5.12	5.13	5.13	6.02	5.95	6.02	6.19	6.10	6.10
Residual Fuel	4.50	4.07	4.15	4.15	4.26	4.46	4.46	4.47	4.70	4.69
Natural Gas	4.78	3.93	3.95	3.97	4.32	4.36	4.37	4.65	4.83	4.88
Steam Coal	1.25	1.17	1.19	1.20	1.12	1.13	1.13	1.11	1.13	1.12

Table B3. Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Average Price to All Users[12]										
Petroleum Products[2]	9.54	9.44	9.47	9.47	9.79	9.81	9.81	10.23	10.23	10.23
Distillate Fuel	9.16	9.14	9.15	9.15	9.52	9.50	9.49	9.92	9.88	9.90
Jet Fuel	6.20	5.64	5.65	5.65	6.34	6.34	6.34	6.72	6.73	6.73
Liquefied Petroleum Gas	12.85	10.75	10.74	10.74	11.56	11.54	11.56	11.83	11.84	11.81
Motor Gasoline[7]	11.57	11.43	11.46	11.46	11.54	11.54	11.54	12.07	12.06	12.07
Residual Fuel	4.11	3.74	3.73	3.73	3.96	3.96	3.96	4.13	4.13	4.13
Natural Gas	6.40	5.17	5.17	5.19	5.35	5.34	5.35	5.66	5.78	5.82
Coal	1.26	1.19	1.20	1.21	1.13	1.14	1.14	1.12	1.14	1.13
Ethanol (E85)[10]	17.72	21.29	21.33	21.34	22.85	22.87	22.88	23.57	23.51	23.53
Electricity	21.33	18.86	19.51	19.61	19.83	20.23	20.33	19.96	20.54	20.60
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.71	168.69	171.46	172.07	191.80	193.55	193.88	204.81	208.37	208.81
Commercial	127.27	128.81	131.61	132.14	165.91	167.57	167.91	183.97	187.30	187.64
Industrial	135.32	138.54	140.25	140.74	173.29	174.68	175.41	192.57	195.97	196.42
Transportation	270.40	327.78	328.18	328.10	402.17	401.96	401.69	457.13	456.28	456.59
Total Non-Renewable Expenditures	699.70	763.82	771.50	773.06	933.17	937.77	938.88	1038.49	1047.92	1049.47
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.10	0.10	0.13	0.13	0.13
Total Expenditures	**699.71**	**763.87**	**771.55**	**773.10**	**933.27**	**937.87**	**938.98**	**1038.62**	**1048.05**	**1049.60**

[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 combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price 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. Price includes estimated motor vehicle fuel taxes.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[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 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B4. Electricity Supply, Disposition, Prices, and Emissions

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2216	2161	2145	2472	2332	2311	2726	2527	2508
Petroleum	113	44	34	33	53	36	32	58	47	47
Natural Gas[3]	411	677	696	708	1140	1253	1266	1289	1443	1452
Nuclear Power	769	787	787	787	790	790	790	790	790	790
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	392	399	400	415	426	427	424	434	434
Distributed Generation (Natural Gas)	0	1	1	1	5	5	5	7	7	7
Non-Utility Generation for Own Use	-21	-24	-24	-24	-24	-24	-24	-24	-23	-23
Total	**3370**	**4091**	**4054**	**4049**	**4850**	**4817**	**4806**	**5270**	**5225**	**5213**
Combined Heat and Power[5]										
Coal	33	33	32	32	33	32	32	33	31	31
Petroleum	7	4	4	4	4	4	4	3	4	4
Natural Gas	124	180	181	183	174	168	167	164	157	155
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-18	-18	-18	-18	-18	-18
Total	**162**	**203**	**203**	**205**	**197**	**190**	**189**	**187**	**178**	**177**
Net Available to the Grid	**3532**	**4294**	**4257**	**4254**	**5047**	**5008**	**4995**	**5457**	**5403**	**5389**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6	6
Natural Gas	83	107	112	113	151	162	166	187	202	209
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	8	8	8
Renewable Sources[4]	31	40	40	40	51	51	51	56	56	56
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**194**	**199**	**200**	**249**	**260**	**264**	**292**	**307**	**313**
Other End-Use Generators[9]	4	5	5	5	6	6	6	6	6	6
Generation for Own Use	-137	-155	-158	-158	-188	-195	-197	-215	-225	-228
Total Sales to the Grid	**27**	**44**	**46**	**46**	**66**	**71**	**73**	**83**	**89**	**91**
Net Imports	**20**	**32**	**35**	**36**	**20**	**21**	**22**	**8**	**9**	**9**
Electricity Sales by Sector										
Residential	1201	1444	1432	1431	1637	1625	1622	1742	1726	1724
Commercial	1197	1468	1459	1459	1803	1791	1787	1982	1968	1966
Industrial	994	1162	1156	1155	1360	1354	1352	1462	1452	1448
Transportation	22	27	27	27	36	36	36	41	41	41
Total	**3414**	**4100**	**4074**	**4072**	**4836**	**4807**	**4797**	**5228**	**5187**	**5179**
End-Use Prices[10] **(2001 cents per kilowatthour)**										
Residential	8.7	7.7	8.0	8.0	7.9	8.1	8.1	8.0	8.2	8.2
Commercial	7.9	6.8	7.0	7.0	7.3	7.4	7.5	7.4	7.6	7.6
Industrial	4.8	4.4	4.6	4.6	4.7	4.8	4.8	4.7	4.9	4.9
Transportation	7.5	6.5	6.7	6.8	6.4	6.5	6.5	6.2	6.4	6.4
All Sectors Average	**7.3**	**6.4**	**6.7**	**6.7**	**6.8**	**6.9**	**6.9**	**6.8**	**7.0**	**7.0**
Prices by Service Category[10] **(2001 cents per kilowatthour)**										
Generation	4.7	3.9	4.1	4.2	4.3	4.4	4.4	4.3	4.5	4.5
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Distribution	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.9

Table B4. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Emissions										
Sulfur Dioxide (million tons)	10.64	9.66	6.03	5.72	8.95	4.43	4.47	8.95	4.21	4.29
Nitrogen Oxide (million tons)	4.75	3.93	2.06	2.05	4.05	1.73	1.72	4.11	1.74	1.74
Mercury (tons)	49.49	52.56	44.52	30.68	53.43	43.33	28.21	54.33	44.73	29.32

[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.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include 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.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: 2001 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 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run IMBASE.D080503A. **Projections**: EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Electric PowerSector[2]										
Power Only[3]										
Coal Steam	305.3	306.8	303.0	302.5	337.5	321.4	320.1	372.1	348.2	346.9
Other Fossil Steam[4]	133.8	89.0	87.7	87.7	82.9	74.5	74.6	82.1	73.7	73.3
Combined Cycle	43.2	135.2	137.4	137.6	200.1	220.5	219.7	239.2	263.6	267.6
Combustion Turbine/Diesel	97.6	136.8	133.7	134.9	171.9	170.5	169.5	192.8	192.6	191.7
Nuclear Power[5]	98.2	98.3	98.3	98.3	98.6	98.6	98.6	98.6	98.6	98.6
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	97.0	97.3	97.3	101.3	102.3	102.4	102.9	103.8	103.5
Distributed Generation[7]	0.0	1.6	1.8	1.8	10.6	10.7	10.3	16.3	16.9	16.1
Total	**788.3**	**885.1**	**879.6**	**880.5**	**1023.5**	**1019.0**	**1015.7**	**1124.7**	**1118.0**	**1118.1**
Combined Heat and Power[8]										
Coal Steam	5.2	5.1	4.7	4.7	5.1	4.7	4.7	5.1	4.7	4.7
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.7**	**44.3**	**44.3**	**44.7**	**44.3**	**44.3**	**44.7**	**44.3**	**44.3**
Total Electric Power Industry	**822.0**	**929.8**	**923.9**	**924.8**	**1068.3**	**1063.3**	**1060.0**	**1169.4**	**1162.3**	**1162.5**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.5	6.5	6.5	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.7**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	8.2	4.9	4.4	40.8	26.7	25.4	76.5	54.6	53.3
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	19.4	21.4	21.2	84.3	104.6	103.3	123.4	147.8	151.4
Combustion Turbine/Diesel	0.0	13.8	12.6	13.0	51.8	52.8	50.9	75.6	75.7	74.6
Nuclear Power	0.0	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	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.3	1.6	1.6	4.1	5.0	5.1	5.6	6.5	6.2
Distributed Generation[7]	0.0	1.6	1.8	1.8	10.6	10.7	10.3	16.3	16.9	16.1
Total	**0.0**	**44.3**	**42.4**	**42.1**	**191.6**	**199.8**	**195.0**	**297.4**	**301.5**	**301.6**
Cumulative Total Additions	**0.0**	**164.3**	**162.4**	**162.1**	**313.3**	**321.5**	**316.7**	**419.2**	**423.3**	**423.4**
Cumulative Retirements[10]										
Coal Steam	0.0	6.9	7.8	7.8	8.7	11.1	11.1	9.8	12.2	12.2
Other Fossil Steam[4]	0.0	43.3	44.6	44.6	49.4	57.8	57.7	50.2	58.6	59.0
Combined Cycle	0.0	1.2	1.1	0.7	1.2	1.1	0.7	1.2	1.3	0.9
Combustion Turbine/Diesel	0.0	5.6	7.6	6.8	8.5	10.9	10.0	11.4	11.8	11.6
Nuclear Power	0.0	2.8	2.8	2.8	3.8	3.8	3.8	3.8	3.8	3.8
Pumped Storage	0.0	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	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**60.0**	**64.0**	**62.8**	**71.7**	**84.9**	**83.5**	**76.5**	**87.8**	**87.7**

Table B5. Electricity Generating Capacity (Continued)

(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.5	17.3	17.9	18.0	23.2	24.8	25.3	28.2	30.4	31.2
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Renewable Sources[6]	4.7	6.2	6.2	6.2	8.1	8.1	8.1	9.0	9.0	9.0
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.7**	**32.1**	**32.7**	**32.8**	**40.0**	**41.5**	**42.1**	**46.0**	**48.1**	**49.0**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	1.7	1.7	2.0	2.1	2.1
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	4.4	5.0	5.1	12.3	13.8	14.3	18.4	20.4	21.2
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.6	0.6	0.9	0.9	0.9

[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 4.3 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[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, 2001.
[10]Cumulative total retirements after December 31, 2001.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include 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.
[13]See Table B9 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B6. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Production										
Dry Gas Production[1]	19.45	21.68	21.78	21.86	25.50	25.58	25.49	26.44	26.62	26.71
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.86**	**4.92**	**4.95**	**6.84**	**7.43**	**7.58**	**8.07**	**8.79**	**8.74**
Canada	3.61	4.22	4.28	4.30	5.05	5.05	5.08	5.20	5.26	5.29
Mexico	-0.13	-0.20	-0.20	-0.20	0.17	0.27	0.27	0.58	0.60	0.61
Liquefied Natural Gas	0.26	0.84	0.84	0.86	1.62	2.10	2.23	2.29	2.93	2.84
Total Supply	**23.26**	**26.64**	**26.79**	**26.91**	**32.43**	**33.10**	**33.17**	**34.60**	**35.51**	**35.55**
Consumption by Sector										
Residential	4.81	5.48	5.47	5.47	5.94	5.94	5.93	6.21	6.18	6.18
Commercial	3.24	3.64	3.63	3.63	4.12	4.12	4.12	4.39	4.37	4.37
Industrial[3]	7.53	8.82	8.84	8.85	10.22	10.28	10.27	10.97	11.04	11.06
Electric Generators[4]	5.30	6.82	6.95	7.05	9.80	10.41	10.51	10.54	11.41	11.43
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.61	0.76	0.77	0.77	0.95	0.96	0.95	1.00	1.01	1.01
Lease and Plant Fuel[6]	1.17	1.34	1.35	1.35	1.61	1.61	1.61	1.69	1.69	1.70
Total	**22.67**	**26.92**	**27.07**	**27.19**	**32.74**	**33.41**	**33.48**	**34.91**	**35.82**	**35.86**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.28**	**-0.28**	**-0.28**	**-0.30**	**-0.31**	**-0.31**	**-0.31**	**-0.31**	**-0.31**

[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 consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4]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.

[5]Compressed natural gas used as vehicle fuel.

[6]Represents natural gas used in the field gathering and processing plant machinery.

[7]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, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B7. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.88**	**23.89**	**23.89**	**25.04**	**25.04**	**24.98**	**26.18**	**26.21**	**26.24**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.64**	**5.64**	**5.64**	**5.43**	**5.43**	**5.43**	**5.33**	**5.32**	**5.33**
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.06	2.06	2.06	1.92	1.92	1.92
Lower 48 Offshore	1.71	2.52	2.52	2.52	2.14	2.14	2.14	2.24	2.23	2.24
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.72**	**17.73**	**17.73**	**15.46**	**15.44**	**15.46**	**15.11**	**15.08**	**15.11**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.42**	**3.43**	**3.45**	**3.67**	**3.66**	**3.67**	**3.97**	**4.10**	**4.14**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**21.68**	**21.78**	**21.86**	**25.50**	**25.58**	**25.49**	**26.44**	**26.62**	**26.71**
Lower 48 Onshore	13.72	15.75	15.74	15.84	17.52	17.76	17.60	17.85	18.04	18.13
Associated-Dissolved[4]	1.77	1.37	1.37	1.37	1.19	1.19	1.19	1.13	1.13	1.13
Non-Associated	11.94	14.38	14.38	14.48	16.33	16.56	16.41	16.72	16.91	16.99
Conventional	6.54	7.12	7.09	7.16	7.08	7.12	7.05	7.06	7.11	7.16
Unconventional	5.40	7.26	7.28	7.32	9.25	9.45	9.36	9.67	9.80	9.84
Lower 48 Offshore	5.30	5.45	5.56	5.54	5.58	5.43	5.50	5.73	5.73	5.74
Associated-Dissolved[4]	1.08	0.96	0.96	0.96	0.80	0.80	0.80	0.83	0.82	0.83
Non-Associated	4.22	4.49	4.60	4.58	4.78	4.63	4.70	4.91	4.91	4.91
Alaska	0.43	0.48	0.48	0.48	2.39	2.39	2.39	2.85	2.85	2.85
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**186.40**	**186.62**	**186.54**	**194.61**	**194.73**	**195.53**	**190.76**	**189.94**	**190.72**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.76**	**25.87**	**25.86**	**26.21**	**26.14**	**26.18**	**27.50**	**27.68**	**27.71**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B8. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Production[1]										
Appalachia	443	420	394	413	407	366	402	420	357	384
Interior	147	155	129	143	147	96	121	158	99	111
West	548	666	700	646	800	848	748	875	936	872
East of the Mississippi	539	527	481	514	517	435	495	542	429	470
West of the Mississippi	599	713	743	688	837	875	776	911	964	897
Total	**1138**	**1240**	**1223**	**1202**	**1355**	**1311**	**1271**	**1453**	**1392**	**1367**
Net Imports										
Imports	20	20	20	20	25	25	25	28	28	28
Exports	49	34	34	33	29	29	29	24	27	24
Total	**-29**	**-14**	**-14**	**-13**	**-4**	**-4**	**-4**	**4**	**1**	**3**
Total Supply[2]	**1109**	**1227**	**1209**	**1189**	**1351**	**1307**	**1267**	**1457**	**1393**	**1370**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	67	67	67	70	70	70	71	71	71
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	20	20	20	18	18	18
Electric Generators[4]	957	1136	1119	1097	1262	1217	1179	1369	1305	1278
Total	**1050**	**1232**	**1214**	**1192**	**1357**	**1312**	**1274**	**1463**	**1400**	**1373**
Discrepancy and Stock Change[5]	**59**	**-5**	**-5**	**-3**	**-6**	**-5**	**-8**	**-7**	**-7**	**-3**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.06	14.67	15.54	14.23	13.29	14.42	14.22	13.06	13.66
(2001 dollars per million Btu)	0.83	0.73	0.72	0.75	0.70	0.66	0.70	0.70	0.66	0.68
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.83	30.05	29.84	30.25	28.37	27.49	27.86	27.91	26.88	27.16
Coke Plants	46.42	41.25	41.36	41.17	38.11	38.08	38.25	36.77	36.72	36.66
Electric Generators										
(2001 dollars per short ton)	25.05	23.71	23.99	24.42	22.37	22.38	22.88	22.17	22.26	22.37
(2001 dollars per million Btu)	1.25	1.17	1.19	1.20	1.12	1.13	1.13	1.11	1.13	1.12
Average	**26.05**	**24.40**	**24.66**	**25.09**	**22.91**	**22.89**	**23.39**	**22.63**	**22.68**	**22.81**
Exports[7]	36.97	32.68	32.73	32.77	30.90	30.70	31.00	30.40	29.80	30.17

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.
[2]Production plus net imports and 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 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B9. Coal Production by Region and Type

(Million Short Tons)

Supply Regions and Coal Types	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Northern Appalachia	**153.6**	**135.2**	**117.3**	**124.3**	**131.0**	**105.3**	**118.7**	**143.2**	**104.3**	**108.5**
Medium Sulfur (Premium)[1]	3.8	2.5	2.5	2.5	2.3	2.3	2.3	2.4	2.4	2.4
Low Sulfur (Bituminous)[2]	0.4	0.0	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0
Medium Sulfur (Bituminous)[2]	75.2	67.1	59.5	60.4	62.6	61.2	62.4	70.6	62.4	62.8
High Sulfur (Bituminous)	63.6	54.2	45.5	51.7	54.6	32.0	44.2	58.8	29.8	33.7
High Sulfur (Gob)[3]	10.6	11.4	9.7	9.7	11.4	9.7	9.7	11.4	9.7	9.7
Central Appalachia	**267.0**	**264.5**	**257.8**	**268.4**	**259.6**	**246.5**	**267.2**	**261.3**	**239.6**	**261.0**
Medium Sulfur (Premium)[1]	38.9	31.9	32.0	31.2	27.1	27.1	27.1	24.2	24.2	24.2
Low Sulfur (Bituminous)	71.2	73.6	79.5	78.5	70.6	71.4	81.8	72.1	70.2	80.2
Medium Sulfur (Bituminous)	156.8	159.0	146.4	158.7	161.9	148.0	158.4	165.0	145.1	156.7
Southern Appalachia	**22.8**	**20.1**	**19.2**	**20.6**	**16.8**	**14.4**	**16.0**	**15.3**	**13.4**	**14.2**
Low Sulfur (Premium)[1]	6.7	6.0	6.1	6.0	4.9	4.9	4.8	4.2	4.2	4.2
Low Sulfur (Bituminous)	5.9	4.0	4.1	4.9	3.8	3.6	4.2	3.5	3.5	3.9
Medium Sulfur (Bituminous)	10.2	10.0	9.0	9.7	8.1	6.0	6.9	7.6	5.8	6.1
Eastern Interior	**96.0**	**107.4**	**86.5**	**100.9**	**110.0**	**69.1**	**93.2**	**122.4**	**71.4**	**85.9**
Medium Sulfur (Bituminous)	33.6	33.7	28.7	32.4	38.4	34.7	42.2	41.3	37.9	41.4
High Sulfur (Bituminous)	61.8	69.7	54.1	65.6	67.8	31.5	48.0	77.4	30.6	41.6
Medium Sulfur (Lignite)	0.6	4.1	3.7	2.9	3.8	2.9	2.9	3.7	2.9	2.9
Western Interior High Sulfur (Bituminous)	**2.4**	**2.5**	**1.6**	**1.3**	**2.0**	**0.5**	**0.6**	**1.8**	**0.4**	**0.4**
Gulf	**48.6**	**45.1**	**40.9**	**40.8**	**35.2**	**26.8**	**26.8**	**33.7**	**26.8**	**24.7**
Medium Sulfur (Lignite)	33.4	28.0	28.3	29.0	21.4	22.7	22.5	20.3	23.0	21.3
High Sulfur (Lignite)	15.2	17.1	12.6	11.8	13.9	4.1	4.3	13.4	3.8	3.4
Dakota Medium Sulfur (Lignite)	**30.8**	**31.6**	**30.9**	**30.9**	**33.5**	**19.9**	**19.8**	**33.6**	**20.1**	**20.0**
Powder/Green River	**407.5**	**511.4**	**531.7**	**475.8**	**641.9**	**702.5**	**592.4**	**705.5**	**790.2**	**718.9**
Low Sulfur (Bituminous)	0.0	1.6	1.6	1.6	1.3	1.5	1.1	0.8	1.1	0.8
Low Sulfur (Sub-Bituminous)	375.1	483.2	499.4	443.5	603.7	668.3	561.3	659.9	749.1	682.3
Medium Sulfur (Sub-Bituminous)	32.5	26.6	30.7	30.7	36.9	32.6	30.0	44.8	40.0	35.8
Rocky Mountain	**60.3**	**81.7**	**95.5**	**97.2**	**87.6**	**88.4**	**98.4**	**98.9**	**88.9**	**95.5**
Low Sulfur (Bituminous)	50.5	72.5	86.3	88.0	81.1	81.9	91.8	92.4	82.4	89.0
Low Sulfur (Sub-Bituminous)	9.8	9.2	9.2	9.2	6.5	6.5	6.5	6.5	6.5	6.5
Arizona/New Mexico	**43.0**	**34.8**	**35.8**	**36.0**	**30.8**	**30.8**	**31.3**	**30.8**	**30.8**	**31.3**
Low Sulfur (Bituminous)	20.9	16.3	17.2	17.5	14.2	14.2	14.7	14.2	14.2	14.7
Medium Sulfur (Bituminous)	0.7	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Medium Sulfur (Sub-bituminous)	21.5	11.5	11.5	11.5	9.5	9.5	9.5	9.5	9.5	9.5
Washington/Alaska Medium Sulfur (Sub-Bituminous)	**6.1**	**6.2**	**6.2**	**6.2**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**

Table B9. Coal Production by Region and Type (Continued)

(Million Short Tons)

Supply Regions and Coal Types	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Subtotals: All Regions										
Premium Metallurgical[1]	49.5	40.4	40.5	39.7	34.3	34.3	34.3	30.8	30.7	30.8
Bituminous	553.2	571.2	540.8	577.4	573.5	493.8	563.5	612.7	490.5	538.3
Sub-Bituminous	445.0	536.7	557.0	501.1	662.9	723.3	613.7	727.0	811.6	740.4
Lignite	90.6	92.1	85.1	84.4	83.9	59.2	59.2	82.4	59.5	57.3
Low Sulfur	540.5	666.4	703.5	649.2	786.1	852.4	766.3	853.6	931.2	881.5
Medium Sulfur	444.2	419.1	396.4	413.2	418.8	380.3	397.6	436.4	386.8	396.5
High Sulfur	153.6	154.9	123.5	140.0	149.7	77.8	106.8	162.9	74.2	88.8
Underground	380.2	405.4	387.3	409.6	420.0	364.9	413.0	452.8	366.5	397.2
Surface	758.1	835.0	836.1	792.8	934.7	945.7	857.7	1000.1	1025.8	969.5
U.S. Total	**1138.3**	**1240.4**	**1223.4**	**1202.4**	**1354.6**	**1310.6**	**1270.7**	**1452.9**	**1392.2**	**1366.8**

[1]"Premium" coal is used to make metallurgical coke.
[2]Includes Pennsylvania anthracite.
[3]Waste coal delivered to Independent Power Producers (IPP) that is not included in other Energy Information Administration coal production tables. The totals for this table include this waste coal tonnage.

Northern Appalachia: Pennsylvania, Maryland, Ohio, Northern West Virginia (Pennsylvania anthracite is included under low and medium sulfur bituminous).
Central Appalachia: Southern West Virginia, Virginia, Eastern Kentucky.
Southern Appalachia: Alabama, Tennessee.
Eastern Interior: Illinois, Indiana, Mississippi, Western Kentucky.
Western Interior (Bituminous only): Iowa, Missouri, Kansas, Oklahoma, Arkansas, Texas.
Gulf (Lignite only): Texas, Louisiana, Arkansas.
Dakota: North Dakota, Eastern Montana (Lignite only).
Powder/Green River: Wyoming, Montana (Sub-Bituminous and Bituminous)
Rocky Mountain: Colorado, Utah.
Sulfur Definitions:
Low Sulfur: 0 - 0.60 pounds of sulfur per million British thermal unit.
Medium Sulfur: 0.61 - 1.67 pounds of sulfur per million British thermal unit.
High Sulfur: Over 1.67 pounds of sulfur per million British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B10. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.10	78.66	78.66	78.66	78.65	78.65	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	3.81	3.90	3.89	5.46	5.70	5.69	5.94	6.21	6.23
Municipal Solid Waste[3]	3.25	3.99	3.99	3.99	4.32	4.38	4.38	4.39	4.39	4.39
Wood and Other Biomass[4]	1.80	2.09	2.09	2.09	2.24	2.20	2.20	2.36	2.20	2.20
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	8.13	8.39	8.39	10.15	10.85	10.95	10.98	11.76	11.46
Total	**90.62**	**97.22**	**97.56**	**97.56**	**101.57**	**102.53**	**102.62**	**103.19**	**104.06**	**103.78**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.90	300.89	300.89	300.07	300.06	300.05	300.36	300.35	300.34
Geothermal[2]	13.81	21.99	22.70	22.68	35.54	37.47	37.41	39.58	41.64	41.71
Municipal Solid Waste[3]	19.55	28.52	28.52	28.52	30.99	31.44	31.44	31.61	31.60	31.60
Wood and Other Biomass[4]	9.38	20.88	26.76	26.99	21.51	27.43	27.74	22.02	27.32	27.70
Dedicated Plants	7.67	12.44	12.32	12.22	13.41	12.87	12.81	14.09	12.92	12.81
Cofiring	1.71	8.44	14.43	14.77	8.10	14.56	14.93	7.94	14.40	14.89
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	22.55	23.47	23.47	29.65	32.19	32.54	32.68	35.53	34.46
Total	**262.85**	**395.86**	**403.35**	**403.57**	**419.31**	**430.14**	**430.73**	**428.11**	**438.30**	**437.66**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.92	5.91	5.91	7.79	7.80	7.80	8.74	8.74	8.74
Total	**4.69**	**6.21**	**6.20**	**6.20**	**8.07**	**8.08**	**8.08**	**9.03**	**9.02**	**9.02**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.62	0.62	0.62	0.96	0.96	0.96
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.71**	**1.71**	**1.71**	**2.05**	**2.05**	**2.05**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.51	37.45	37.45	48.42	48.46	48.45	53.98	53.96	53.95
Total	**31.13**	**39.66**	**39.61**	**39.60**	**50.57**	**50.61**	**50.60**	**56.13**	**56.12**	**56.10**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.32	1.33	1.32	2.02	2.03	2.02
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.56**	**5.57**	**5.56**	**6.25**	**6.26**	**6.25**

[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]Includes projections for energy crops after 2010.
[5]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Includes 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 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. 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: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B11. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.6	25.7	25.7	25.0	25.0	25.0
Natural Gas	71.1	81.1	81.0	81.0	88.0	87.9	87.8	91.9	91.4	91.5
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Electricity	215.1	245.7	241.0	239.8	271.6	263.2	261.3	289.5	277.6	276.3
Total	**313.8**	**354.8**	**350.0**	**348.8**	**385.6**	**377.1**	**375.2**	**406.7**	**394.3**	**393.1**
Commercial										
Petroleum	14.0	13.7	13.7	13.7	14.1	14.2	14.2	14.1	14.2	14.2
Natural Gas	48.0	53.8	53.8	53.8	61.0	61.0	60.9	65.0	64.7	64.7
Coal	2.3	2.4	2.4	2.4	2.7	2.7	2.7	2.8	2.8	2.8
Electricity	214.5	249.8	245.5	244.5	299.0	290.1	287.9	329.5	316.5	315.0
Total	**278.8**	**319.8**	**315.5**	**314.4**	**376.8**	**367.9**	**365.6**	**411.3**	**398.2**	**396.7**
Industrial[1]										
Petroleum	97.9	98.0	97.7	97.7	105.0	105.3	105.7	109.4	109.3	109.5
Natural Gas[2]	123.4	147.9	148.3	148.4	171.9	172.8	172.6	184.0	185.3	185.5
Coal	52.1	56.5	56.4	56.3	56.2	56.2	56.1	56.2	56.3	56.2
Electricity	178.1	197.7	194.6	193.7	225.6	219.3	217.7	243.0	233.6	232.0
Total	**451.5**	**500.0**	**497.0**	**496.1**	**558.7**	**553.6**	**552.1**	**592.6**	**584.4**	**583.2**
Transportation										
Petroleum[3]	501.4	611.4	610.7	610.6	737.6	737.4	737.3	802.6	802.1	802.0
Natural Gas[4]	9.2	12.1	12.2	12.3	15.5	15.6	15.5	16.4	16.6	16.6
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	3.9	4.6	4.6	4.6	6.0	5.8	5.8	6.9	6.7	6.6
Total	**514.5**	**628.2**	**627.6**	**627.4**	**759.1**	**758.8**	**758.5**	**826.0**	**825.4**	**825.2**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	750.7	749.8	749.6	882.4	882.6	882.8	951.1	950.6	950.6
Natural Gas	251.7	294.9	295.3	295.5	336.4	337.3	336.8	357.3	358.0	358.3
Coal	54.7	59.3	59.2	59.1	59.2	59.3	59.2	59.3	59.4	59.3
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	611.6	697.8	685.7	682.6	802.2	778.4	772.7	868.9	834.3	830.0
Total	**1558.6**	**1802.7**	**1790.0**	**1786.8**	**2080.2**	**2057.5**	**2051.4**	**2236.6**	**2202.3**	**2198.2**
Electric Generators[6]										
Petroleum	27.5	10.8	8.5	8.4	12.8	9.0	8.3	13.4	10.5	10.4
Natural Gas	77.7	100.0	102.0	103.5	143.8	152.8	154.2	154.7	167.4	167.7
Coal	506.4	587.0	575.3	570.7	645.6	616.6	610.1	700.8	656.3	651.9
Total	**611.6**	**697.8**	**685.7**	**682.6**	**802.2**	**778.4**	**772.7**	**868.9**	**834.3**	**830.0**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	761.5	758.3	758.0	895.2	891.5	891.1	964.5	961.1	961.1
Natural Gas	329.4	395.0	397.3	399.0	480.2	490.0	491.0	512.0	525.4	525.9
Coal	561.1	646.3	634.5	629.8	704.8	675.9	669.3	760.1	715.8	711.2
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1802.7**	**1790.0**	**1786.8**	**2080.2**	**2057.5**	**2051.4**	**2236.6**	**2202.3**	**2198.2**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.6**	**6.0**	**6.0**	**6.0**	**6.4**	**6.3**	**6.3**	**6.6**	**6.5**	**6.5**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Table B12. Emissions, Allowance Prices, and Emission Controls in the Electric Power Sector

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P	Reference	Clear Skies 2P	Clear Skies 3P
Emissions										
Nitrogen Oxides (million tons)	4.75	3.93	2.06	2.05	4.05	1.73	1.72	4.11	1.74	1.74
Sulfur Dioxide (million tons)	10.64	9.66	6.03	5.72	8.95	4.43	4.47	8.95	4.21	4.29
From Coal	10.05	9.47	5.91	5.60	8.72	4.32	4.36	8.75	4.11	4.19
From Oil/Other	0.60	0.19	0.12	0.12	0.23	0.11	0.11	0.20	0.10	0.10
Mercury (tons)	49.49	52.56	44.52	30.68	53.43	43.33	28.21	54.33	44.73	29.32
Carbon Dioxide (million metric tons carbon equivalent)	611.57	697.82	685.73	682.58	802.16	778.38	772.68	868.91	834.32	829.99
Allowance Prices										
Nitrogen Oxides (2001 dollars per ton)										
Regional/Seasonal	0.00	4741.70	0.00	0.00	5550.48	0.00	0.00	6207.45	0.00	0.00
East/Annual	0.00	0.00	2607.56	2425.83	0.00	2472.62	2422.65	0.00	2601.57	2549.15
West/Annual	0.00	0.00	1692.37	1802.62	0.00	1811.41	1751.79	0.00	1895.14	1843.55
Sulfur Dioxide (2001 dollars per ton)	76.93	100.52	681.36	573.50	89.80	987.74	965.64	51.70	1210.92	1066.78
Mercury (thousand 2001 dollars per pound)	0.00	0.00	0.00	35.00	0.00	0.00	35.00	0.00	0.00	35.00
Carbon Dioxide (2001 dollars per million metric ton carbon equivalent)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)										
Scrubber[6]										
Planned	1.49	20.65	20.65	20.65	22.82	22.82	22.82	22.82	22.82	22.82
Unplanned	0.00	0.00	32.36	45.20	0.00	61.71	62.48	0.00	61.71	63.38
Total	1.49	20.65	53.01	65.85	22.82	84.53	85.30	22.82	84.53	86.20
Nitrogen Oxides Controls										
Combustion	0.00	16.01	24.95	25.17	17.45	31.00	30.46	17.83	31.48	31.41
SCR Post-combustion	0.00	79.20	137.48	136.90	83.24	168.57	171.03	84.52	169.96	172.30
SNCR Post-combustion	0.00	16.67	8.85	8.93	35.40	35.28	26.97	47.18	44.52	37.20
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs per million Btu)	540.47	666.41	703.46	649.17	786.14	852.44	766.33	853.64	931.20	881.48
Medium Sulfur	444.21	419.09	396.42	413.22	418.81	380.34	397.58	436.35	386.79	396.52
High Sulfur (> 1.67 lbs per million Btu)	153.63	154.89	123.52	140.04	149.68	77.79	106.78	162.92	74.25	88.76
Interregional Sulfur Dioxide Allowances										
Target (million tons)	9.48	8.95	4.50	4.50	8.95	3.00	3.00	8.95	3.00	3.00
Cumulative Banked Allowances	9.23	1.03	19.22	19.15	0.00	9.99	10.85	0.00	3.42	4.08
Coal Characteristics										
SO_2 Content (lbs per million Btu)	1.85	1.73	1.59	1.70	1.62	1.33	1.50	1.62	1.28	1.37
Mercury Content (lbs per trillion Btu)	7.50	7.25	7.02	7.11	7.04	6.75	6.85	6.99	6.67	6.73
ACI Controls (gigawatts)										
Spray Cooling	0.00	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	0.00	0.78	0.00	0.00	5.63	0.00	0.00	5.63
ACI Mercury Removal (tons)	**0.00**	**0.00**	**0.00**	**11.06**	**0.00**	**0.00**	**11.55**	**0.00**	**0.00**	**13.06**
Allowance Revenues (billion 2001 dollars)										
Nitrogen Oxides	0.00	2.24	5.04	4.80	2.63	3.89	3.80	2.94	4.09	4.00
Sulfur Dioxide	2.02	1.74	4.98	5.11	1.30	8.13	8.19	1.10	9.66	9.56
Mercury	0.00	0.00	0.00	2.15	0.00	0.00	1.97	0.00	0.00	2.05
Carbon Dioxide	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**2.02**	**3.98**	**10.02**	**12.05**	**3.92**	**12.02**	**13.96**	**4.03**	**13.75**	**15.61**

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 2001 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PWS.D080503A.

Appendix C Tables:

Reference, Clear Skies 2P, Clear Skies 3P no Safety

Table C1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Production										
Crude Oil and Lease Condensate	12.29	11.93	11.94	11.94	11.50	11.50	11.50	11.29	11.26	11.27
Natural Gas Plant Liquids	2.65	3.14	3.15	3.17	3.59	3.60	3.61	3.71	3.74	3.76
Dry Natural Gas	19.97	22.26	22.37	22.46	26.18	26.27	26.31	27.15	27.34	27.49
Coal	23.97	25.56	25.09	24.88	27.53	26.39	25.92	29.48	27.75	27.30
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[1]	5.32	7.28	7.37	7.38	8.36	8.52	8.55	8.81	8.97	9.00
Other[2]	0.57	0.85	0.85	0.85	0.79	0.79	0.79	0.80	0.80	0.80
Total	**72.80**	**79.24**	**78.99**	**78.90**	**86.21**	**85.32**	**84.93**	**89.49**	**88.11**	**87.87**
Imports										
Crude Oil[3]	20.26	25.07	25.02	25.03	27.60	27.59	27.57	28.55	28.47	28.46
Petroleum Products[4]	5.04	6.34	6.21	6.18	11.68	11.52	11.50	14.86	14.80	14.78
Natural Gas	4.18	5.54	5.60	5.64	7.37	7.96	8.11	8.61	9.35	9.38
Other Imports[5]	0.73	0.94	0.97	0.98	0.99	1.00	1.01	0.95	0.96	0.96
Total	**30.21**	**37.89**	**37.79**	**37.83**	**47.63**	**48.08**	**48.19**	**52.96**	**53.58**	**53.58**
Exports										
Petroleum[6]	2.01	2.25	2.25	2.25	2.34	2.36	2.34	2.42	2.44	2.43
Natural Gas	0.37	0.56	0.56	0.56	0.37	0.36	0.36	0.36	0.35	0.35
Coal	1.27	0.87	0.87	0.86	0.74	0.74	0.74	0.61	0.69	0.65
Total	**3.64**	**3.67**	**3.69**	**3.68**	**3.46**	**3.47**	**3.45**	**3.39**	**3.48**	**3.43**
Discrepancy[7]	**2.08**	**0.22**	**0.22**	**0.22**	**0.22**	**0.23**	**0.19**	**0.20**	**0.22**	**0.27**
Consumption										
Petroleum Products[8]	38.46	44.48	44.31	44.31	52.20	52.04	52.01	56.18	56.03	56.03
Natural Gas	23.26	27.61	27.77	27.90	33.56	34.25	34.45	35.79	36.72	36.90
Coal	22.02	25.32	24.85	24.65	27.58	26.41	25.99	29.75	27.94	27.49
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[1]	5.32	7.28	7.37	7.38	8.36	8.53	8.55	8.81	8.97	9.00
Other[9]	0.21	0.33	0.36	0.37	0.21	0.22	0.22	0.08	0.09	0.09
Total	**97.29**	**113.24**	**112.87**	**112.83**	**130.17**	**129.70**	**129.47**	**138.87**	**138.00**	**137.76**
Net Imports - Petroleum	**23.29**	**29.16**	**28.98**	**28.96**	**36.93**	**36.76**	**36.73**	**40.99**	**40.84**	**40.81**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.99	23.99	25.48	25.48	25.48	26.57	26.57	26.57
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.42	3.43	3.44	3.67	3.66	3.68	3.97	4.10	4.15
Coal Minemouth Price (dollars per ton)	17.59	15.06	14.67	15.68	14.23	13.29	15.66	14.22	13.06	16.24
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.7	6.7	6.8	6.9	7.0	6.8	7.0	7.1

[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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.84	0.84	0.81	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.46	0.46	0.46	0.46	0.47	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.36	1.36	1.36	1.33	1.33	1.33
Natural Gas	4.94	5.63	5.63	5.63	6.11	6.11	6.10	6.38	6.35	6.35
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.41	0.41	0.41	0.40	0.40	0.40
Electricity	4.10	4.93	4.89	4.88	5.59	5.55	5.53	5.94	5.89	5.87
Delivered Energy	**10.94**	**12.44**	**12.40**	**12.39**	**13.48**	**13.43**	**13.41**	**14.07**	**13.98**	**13.96**
Electricity Related Losses	9.15	10.41	10.30	10.29	11.13	10.96	10.91	11.51	11.24	11.18
Total	**20.08**	**22.85**	**22.70**	**22.68**	**24.61**	**24.40**	**24.32**	**25.58**	**25.23**	**25.14**
Commercial										
Distillate Fuel	0.46	0.51	0.51	0.51	0.52	0.53	0.53	0.52	0.53	0.53
Residual Fuel	0.09	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.70	0.72	0.73	0.73	0.72	0.73	0.73
Natural Gas	3.33	3.74	3.73	3.73	4.24	4.23	4.23	4.51	4.49	4.49
Coal	0.09	0.10	0.10	0.10	0.10	0.11	0.10	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	5.01	4.98	4.98	6.15	6.11	6.09	6.76	6.71	6.70
Delivered Energy	**8.32**	**9.65**	**9.62**	**9.62**	**11.32**	**11.28**	**11.26**	**12.21**	**12.15**	**12.13**
Electricity Related Losses	9.12	10.58	10.50	10.49	12.26	12.08	12.02	13.10	12.82	12.75
Total	**17.44**	**20.23**	**20.11**	**20.10**	**23.58**	**23.37**	**23.28**	**25.31**	**24.97**	**24.88**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.21	1.21	1.36	1.36	1.35	1.44	1.44	1.44
Liquefied Petroleum Gas	2.10	2.55	2.55	2.55	3.05	3.05	3.06	3.29	3.29	3.30
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	0.23	0.19	0.19	0.19	0.19	0.19	0.19	0.20	0.20	0.20
Motor Gasoline[2]	0.15	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.27	4.26	4.26	4.45	4.47	4.48	4.57	4.58	4.58
Petroleum Subtotal	8.79	9.82	9.80	9.80	10.93	10.96	10.97	11.52	11.52	11.54
Natural Gas	7.74	9.07	9.09	9.10	10.50	10.57	10.57	11.28	11.35	11.36
Lease and Plant Fuel[6]	1.20	1.38	1.38	1.39	1.65	1.66	1.66	1.73	1.74	1.75
Natural Gas Subtotal	8.94	10.45	10.47	10.49	12.15	12.22	12.23	13.01	13.09	13.11
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.42	1.45	1.45	1.45	1.51	1.51	1.51	1.54	1.54	1.54
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.16	2.23	2.22	2.22	2.22	2.22	2.21	2.22	2.22	2.21
Renewable Energy[7]	1.82	2.22	2.22	2.22	2.77	2.77	2.77	3.05	3.05	3.05
Electricity	3.39	3.96	3.94	3.94	4.64	4.62	4.61	4.99	4.96	4.94
Delivered Energy	**25.10**	**28.68**	**28.66**	**28.67**	**32.71**	**32.79**	**32.79**	**34.79**	**34.83**	**34.85**
Electricity Related Losses	7.57	8.37	8.32	8.30	9.25	9.13	9.09	9.66	9.46	9.40
Total	**32.67**	**37.05**	**36.98**	**36.97**	**41.96**	**41.92**	**41.88**	**44.45**	**44.29**	**44.24**

Table C2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Transportation										
Distillate Fuel[8]	5.44	7.09	7.08	7.07	8.68	8.68	8.67	9.55	9.54	9.52
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.09	5.67	5.66	5.66
Motor Gasoline[2]	16.26	19.81	19.79	19.79	23.57	23.56	23.56	25.48	25.47	25.46
Residual Fuel	0.84	0.83	0.83	0.83	0.86	0.86	0.85	0.87	0.87	0.87
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.07	0.07	0.07	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.97	31.94	31.93	38.57	38.56	38.54	41.97	41.94	41.92
Pipeline Fuel Natural Gas	0.63	0.78	0.79	0.79	0.98	0.98	0.98	1.03	1.04	1.04
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.14
Delivered Energy	**26.94**	**32.91**	**32.88**	**32.88**	**39.78**	**39.77**	**39.75**	**43.26**	**43.24**	**43.22**
Electricity Related Losses	0.17	0.20	0.20	0.20	0.24	0.24	0.24	0.27	0.27	0.27
Total	**27.10**	**33.11**	**33.08**	**33.08**	**40.02**	**40.01**	**39.99**	**43.53**	**43.51**	**43.49**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.73	9.72	9.71	11.40	11.40	11.39	12.32	12.32	12.30
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.09	5.67	5.66	5.66
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.68	3.68	3.69	3.94	3.93	3.95
Motor Gasoline[2]	16.46	20.01	19.99	19.99	23.79	23.78	23.78	25.71	25.70	25.69
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	1.15	1.06	1.06	1.06	1.10	1.10	1.10	1.12	1.12	1.12
Other Petroleum[12]	4.24	4.51	4.49	4.49	4.73	4.75	4.75	4.87	4.87	4.88
Petroleum Subtotal	37.21	43.96	43.90	43.90	51.59	51.61	51.60	55.54	55.52	55.52
Natural Gas	16.02	18.50	18.51	18.52	20.95	21.01	21.01	22.28	22.30	22.31
Lease and Plant Fuel Plant[6]	1.20	1.38	1.38	1.39	1.65	1.66	1.66	1.73	1.74	1.75
Pipeline Natural Gas	0.63	0.78	0.79	0.79	0.98	0.98	0.98	1.03	1.04	1.04
Natural Gas Subtotal	17.86	20.66	20.68	20.70	23.58	23.64	23.64	25.04	25.08	25.10
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.53	1.56	1.56	1.56	1.63	1.63	1.62	1.66	1.66	1.66
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.27	2.34	2.33	2.33	2.33	2.34	2.33	2.34	2.34	2.33
Renewable Energy[13]	2.31	2.74	2.73	2.73	3.29	3.29	3.29	3.57	3.56	3.56
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	13.99	13.90	13.90	16.50	16.40	16.35	17.84	17.70	17.65
Delivered Energy	**71.29**	**83.68**	**83.55**	**83.56**	**97.29**	**97.28**	**97.22**	**104.33**	**104.21**	**104.16**
Electricity Related Losses	26.00	29.56	29.32	29.27	32.88	32.42	32.26	34.54	33.79	33.59
Total	**97.29**	**113.24**	**112.87**	**112.83**	**130.17**	**129.70**	**129.47**	**138.87**	**138.00**	**137.76**
Electric Power[14]										
Distillate Fuel	0.17	0.10	0.10	0.10	0.11	0.13	0.09	0.18	0.21	0.21
Residual Fuel	1.08	0.41	0.31	0.31	0.50	0.30	0.31	0.47	0.30	0.30
Petroleum Subtotal	1.25	0.51	0.41	0.41	0.61	0.43	0.40	0.64	0.51	0.51
Natural Gas	5.40	6.95	7.08	7.20	9.98	10.61	10.81	10.75	11.63	11.79
Steam Coal	19.75	22.99	22.51	22.32	25.25	24.08	23.66	27.41	25.60	25.15
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[15]	3.01	4.55	4.64	4.65	5.08	5.24	5.27	5.25	5.41	5.44
Electricity Imports	0.21	0.33	0.36	0.37	0.21	0.22	0.22	0.08	0.09	0.09
Total	**37.65**	**43.55**	**43.22**	**43.17**	**49.38**	**48.82**	**48.61**	**52.38**	**51.49**	**51.24**

Table C2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Total Energy Consumption										
Distillate Fuel	8.10	9.84	9.82	9.81	11.51	11.53	11.48	12.49	12.53	12.50
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.09	5.67	5.66	5.66
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.68	3.68	3.69	3.94	3.93	3.95
Motor Gasoline[2]	16.46	20.01	19.99	19.99	23.79	23.78	23.78	25.71	25.70	25.69
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	2.23	1.47	1.36	1.37	1.60	1.40	1.40	1.58	1.41	1.42
Other Petroleum[12]	4.24	4.51	4.49	4.49	4.73	4.75	4.75	4.87	4.87	4.88
Petroleum Subtotal	38.46	44.48	44.31	44.31	52.20	52.04	52.01	56.18	56.03	56.03
Natural Gas	21.42	25.45	25.59	25.72	30.93	31.62	31.82	33.03	33.93	34.11
Lease and Plant Fuel[6]	1.20	1.38	1.38	1.39	1.65	1.66	1.66	1.73	1.74	1.75
Pipeline Natural Gas	0.63	0.78	0.79	0.79	0.98	0.98	0.98	1.03	1.04	1.04
Natural Gas Subtotal	23.26	27.61	27.77	27.90	33.56	34.25	34.45	35.79	36.72	36.90
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	21.28	24.55	24.08	23.88	26.88	25.71	25.28	29.07	27.27	26.81
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	22.02	25.32	24.85	24.65	27.58	26.41	25.99	29.75	27.94	27.49
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[16]	5.32	7.28	7.37	7.38	8.36	8.53	8.55	8.81	8.97	9.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.33	0.36	0.37	0.21	0.22	0.22	0.08	0.09	0.09
Total	**97.29**	**113.24**	**112.87**	**112.83**	**130.17**	**129.70**	**129.47**	**138.87**	**138.00**	**137.76**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.68	83.55	83.56	97.29	97.28	97.22	104.33	104.21	104.16
Total Energy Use	97.29	113.24	112.87	112.83	130.17	129.70	129.47	138.87	138.00	137.76
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12254	12238	12238	16448	16459	16457	18914	18913	18912
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.7	1790.0	1786.0	2080.2	2057.5	2045.5	2236.6	2202.3	2188.6

[1]Includes wood used for residential heating. See Table C18 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]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[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 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[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 2001 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: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C3. Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Residential	**15.80**	**14.02**	**14.30**	**14.35**	**14.67**	**14.86**	**14.94**	**14.99**	**15.34**	**15.45**
Primary Energy[1]	9.73	8.08	8.10	8.10	8.30	8.29	8.30	8.59	8.71	8.74
Petroleum Products[2]	10.85	10.02	10.02	10.01	10.92	10.91	10.92	11.23	11.22	11.23
Distillate Fuel	8.99	7.99	7.99	7.99	8.72	8.72	8.72	8.92	8.92	8.92
Liquefied Petroleum Gas	14.84	14.35	14.34	14.34	15.27	15.23	15.27	15.58	15.56	15.59
Natural Gas	9.41	7.60	7.62	7.62	7.73	7.72	7.74	8.05	8.20	8.24
Electricity	25.36	22.58	23.32	23.44	23.22	23.71	23.93	23.31	24.00	24.22
Commercial	**15.50**	**13.49**	**13.84**	**13.89**	**14.79**	**14.99**	**15.09**	**15.20**	**15.55**	**15.69**
Primary Energy[1]	7.81	6.45	6.47	6.47	6.75	6.74	6.75	7.07	7.19	7.22
Petroleum Products[2]	7.27	6.77	6.77	6.77	7.52	7.50	7.50	7.81	7.80	7.79
Distillate Fuel	6.40	5.66	5.67	5.66	6.46	6.46	6.45	6.75	6.75	6.74
Residual Fuel	3.46	4.01	4.00	4.00	4.24	4.21	4.21	4.40	4.37	4.37
Natural Gas	8.09	6.52	6.53	6.54	6.75	6.75	6.76	7.09	7.23	7.27
Electricity	23.27	19.88	20.55	20.64	21.42	21.83	22.01	21.62	22.19	22.43
Industrial[3]	**7.11**	**6.42**	**6.50**	**6.51**	**7.02**	**7.06**	**7.11**	**7.31**	**7.42**	**7.46**
Primary Energy	5.83	5.19	5.19	5.19	5.71	5.70	5.72	6.00	6.06	6.08
Petroleum Products[2]	7.72	7.07	7.07	7.07	7.83	7.82	7.84	8.15	8.16	8.16
Distillate Fuel	6.55	5.74	5.75	5.75	6.73	6.72	6.71	7.18	7.19	7.19
Liquefied Petroleum Gas	12.34	9.92	9.92	9.92	10.83	10.82	10.84	11.14	11.15	11.16
Residual Fuel	3.28	3.72	3.70	3.70	3.95	3.92	3.92	4.11	4.09	4.09
Natural Gas[4]	4.87	4.04	4.05	4.05	4.36	4.37	4.38	4.66	4.79	4.82
Metallurgical Coal	1.69	1.50	1.51	1.51	1.39	1.39	1.39	1.34	1.34	1.34
Steam Coal	1.46	1.38	1.37	1.40	1.31	1.27	1.30	1.29	1.24	1.29
Electricity	14.13	12.95	13.46	13.55	13.67	13.99	14.18	13.78	14.24	14.40
Transportation	**10.28**	**10.20**	**10.23**	**10.21**	**10.37**	**10.37**	**10.37**	**10.83**	**10.81**	**10.81**
Primary Energy	10.25	10.18	10.20	10.18	10.34	10.34	10.34	10.80	10.79	10.78
Petroleum Products[2]	10.25	10.18	10.20	10.18	10.35	10.34	10.35	10.81	10.79	10.78
Distillate Fuel[5]	10.05	10.19	10.19	10.19	10.27	10.25	10.27	10.67	10.62	10.62
Jet Fuel[6]	6.20	5.64	5.65	5.64	6.34	6.34	6.34	6.72	6.73	6.73
Motor Gasoline[7]	11.57	11.43	11.46	11.43	11.54	11.54	11.54	12.07	12.06	12.04
Residual Fuel	3.90	3.57	3.56	3.56	3.78	3.77	3.77	3.95	3.94	3.94
Liquefied Petroleum Gas[8]	16.93	15.52	15.50	15.49	16.01	15.97	16.02	16.04	16.07	16.07
Natural Gas[9]	7.65	7.22	7.24	7.25	7.71	7.71	7.73	8.11	8.27	8.30
Ethanol (E85)[10]	17.72	21.29	21.33	21.31	22.85	22.87	22.88	23.57	23.51	23.63
Electricity	21.87	19.18	19.76	19.87	18.72	19.07	19.24	18.11	18.67	18.88
Average End-Use Energy	**10.74**	**9.99**	**10.10**	**10.11**	**10.50**	**10.55**	**10.59**	**10.88**	**10.99**	**11.03**
Primary Energy	8.52	8.07	8.08	8.07	8.44	8.43	8.44	8.85	8.88	8.88
Electricity	21.33	18.86	19.51	19.61	19.83	20.23	20.43	19.96	20.54	20.75
Electric Power[11]										
Fossil Fuel Average	2.14	1.85	1.89	1.91	2.07	2.15	2.19	2.15	2.33	2.38
Petroleum Products	4.73	4.28	4.39	4.38	4.58	4.90	4.81	4.94	5.29	5.25
Distillate Fuel	6.20	5.12	5.13	5.13	6.02	5.95	6.01	6.19	6.10	6.10
Residual Fuel	4.50	4.07	4.15	4.15	4.26	4.46	4.44	4.47	4.70	4.68
Natural Gas	4.78	3.93	3.95	3.96	4.32	4.36	4.38	4.65	4.83	4.87
Steam Coal	1.25	1.17	1.19	1.20	1.12	1.13	1.15	1.11	1.13	1.16

Table C3. Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Average Price to All Users[12]										
Petroleum Products[2]	9.54	9.44	9.47	9.46	9.79	9.81	9.82	10.23	10.23	10.22
Distillate Fuel	9.16	9.14	9.15	9.15	9.52	9.50	9.52	9.92	9.88	9.88
Jet Fuel	6.20	5.64	5.65	5.64	6.34	6.34	6.34	6.72	6.73	6.73
Liquefied Petroleum Gas	12.85	10.75	10.74	10.74	11.56	11.54	11.56	11.83	11.84	11.84
Motor Gasoline[7]	11.57	11.43	11.46	11.43	11.54	11.54	11.54	12.07	12.06	12.04
Residual Fuel	4.11	3.74	3.73	3.73	3.96	3.96	3.96	4.13	4.13	4.13
Natural Gas	6.40	5.17	5.17	5.18	5.35	5.34	5.35	5.66	5.78	5.81
Coal	1.26	1.19	1.20	1.21	1.13	1.14	1.16	1.12	1.14	1.17
Ethanol (E85)[10]	17.72	21.29	21.33	21.31	22.85	22.87	22.88	23.57	23.51	23.63
Electricity	21.33	18.86	19.51	19.61	19.83	20.23	20.43	19.96	20.54	20.75
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.71	168.69	171.46	172.02	191.80	193.55	194.40	204.81	208.37	209.47
Commercial	127.27	128.81	131.61	132.10	165.91	167.57	168.32	183.97	187.30	188.67
Industrial	135.32	138.54	140.25	140.69	173.29	174.68	175.88	192.57	195.97	197.11
Transportation	270.40	327.78	328.18	327.46	402.17	401.96	401.95	457.13	456.28	455.64
Total Non-Renewable Expenditures	699.70	763.82	771.50	772.27	933.17	937.77	940.55	1038.49	1047.92	1050.89
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.10	0.10	0.13	0.13	0.13
Total Expenditures	**699.71**	**763.87**	**771.55**	**772.31**	**933.27**	**937.87**	**940.64**	**1038.62**	**1048.05**	**1051.02**

[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 combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price 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. Price includes estimated motor vehicle fuel taxes.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C4. Electricity Supply, Disposition, Prices, and Emissions

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2216	2161	2141	2472	2332	2286	2726	2527	2470
Petroleum	113	44	34	33	53	36	32	58	47	47
Natural Gas[3]	411	677	696	711	1140	1253	1283	1289	1443	1479
Nuclear Power	769	787	787	787	790	790	790	790	790	790
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	392	399	400	415	426	428	424	434	437
Distributed Generation (Natural Gas)	0	1	1	1	5	5	5	7	7	7
Non-Utility Generation for Own Use	-21	-24	-24	-24	-24	-24	-24	-24	-23	-23
Total	**3370**	**4091**	**4054**	**4049**	**4850**	**4817**	**4800**	**5270**	**5225**	**5207**
Combined Heat and Power[5]										
Coal	33	33	32	32	33	32	32	33	31	31
Petroleum	7	4	4	4	4	4	4	3	4	4
Natural Gas	124	180	181	183	174	168	166	164	157	155
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-18	-18	-18	-18	-18	-18	-18
Total	**162**	**203**	**203**	**205**	**197**	**190**	**188**	**187**	**178**	**176**
Net Available to the Grid	**3532**	**4294**	**4257**	**4254**	**5047**	**5008**	**4988**	**5457**	**5403**	**5383**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6	6
Natural Gas	83	107	112	114	151	162	168	187	202	211
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	8	8	8
Renewable Sources[4]	31	40	40	40	51	51	51	56	56	56
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**194**	**199**	**201**	**249**	**260**	**266**	**292**	**307**	**316**
Other End-Use Generators[9]	4	5	5	5	6	6	6	6	6	6
Generation for Own Use	-137	-155	-158	-159	-188	-195	-199	-215	-225	-230
Total Sales to the Grid	**27**	**44**	**46**	**47**	**66**	**71**	**73**	**83**	**89**	**92**
Net Imports	**20**	**32**	**35**	**36**	**20**	**21**	**22**	**8**	**9**	**9**
Electricity Sales by Sector										
Residential	1201	1444	1432	1431	1637	1625	1620	1742	1726	1721
Commercial	1197	1468	1459	1459	1803	1791	1785	1982	1968	1962
Industrial	994	1162	1156	1155	1360	1354	1350	1462	1452	1447
Transportation	22	27	27	27	36	36	36	41	41	41
Total	**3414**	**4100**	**4074**	**4073**	**4836**	**4807**	**4792**	**5228**	**5187**	**5172**
End-Use Prices[10] (2001 cents per kilowatthour)										
Residential	8.7	7.7	8.0	8.0	7.9	8.1	8.2	8.0	8.2	8.3
Commercial	7.9	6.8	7.0	7.0	7.3	7.4	7.5	7.4	7.6	7.7
Industrial	4.8	4.4	4.6	4.6	4.7	4.8	4.8	4.7	4.9	4.9
Transportation	7.5	6.5	6.7	6.8	6.4	6.5	6.6	6.2	6.4	6.4
All Sectors Average	**7.3**	**6.4**	**6.7**	**6.7**	**6.8**	**6.9**	**7.0**	**6.8**	**7.0**	**7.1**
Prices by Service Category[10] (2001 cents per kilowatthour)										
Generation	4.7	3.9	4.1	4.2	4.3	4.4	4.5	4.3	4.5	4.6
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Distribution	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.9

Table C4. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Emissions										
Sulfur Dioxide (million tons)	10.64	9.66	6.03	5.82	8.95	4.43	4.41	8.95	4.21	4.04
Nitrogen Oxide (million tons)	4.75	3.93	2.06	2.04	4.05	1.73	1.71	4.11	1.74	1.73
Mercury (tons)	49.49	52.56	44.52	26.00	53.43	43.33	18.70	54.33	44.73	15.00

[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.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include 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.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: 2001 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 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run IMBASE.D080503A. **Projections**: EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Electric PowerSector[2]										
Power Only[3]										
Coal Steam	305.3	306.8	303.0	302.2	337.5	321.4	318.2	372.1	348.2	343.4
Other Fossil Steam[4]	133.8	89.0	87.7	87.7	82.9	74.5	75.0	82.1	73.7	73.8
Combined Cycle	43.2	135.2	137.4	138.0	200.1	220.5	220.4	239.2	263.6	272.4
Combustion Turbine/Diesel	97.6	136.8	133.7	134.3	171.9	170.5	168.3	192.8	192.6	186.7
Nuclear Power[5]	98.2	98.3	98.3	98.3	98.6	98.6	98.6	98.6	98.6	98.6
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	97.0	97.3	97.3	101.3	102.3	102.6	102.9	103.8	103.9
Distributed Generation[7]	0.0	1.6	1.8	1.8	10.6	10.7	10.3	16.3	16.9	16.3
Total	**788.3**	**885.1**	**879.6**	**880.2**	**1023.5**	**1019.0**	**1013.9**	**1124.7**	**1118.0**	**1115.7**
Combined Heat and Power[8]										
Coal Steam	5.2	5.1	4.7	4.7	5.1	4.7	4.7	5.1	4.7	4.7
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.7**	**44.3**	**44.3**	**44.7**	**44.3**	**44.3**	**44.7**	**44.3**	**44.3**
Total Electric Power Industry	**822.0**	**929.8**	**923.9**	**924.5**	**1068.3**	**1063.3**	**1058.2**	**1169.4**	**1162.3**	**1160.0**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.5	6.5	6.5	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.7**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	8.2	4.9	4.0	40.8	26.7	23.3	76.5	54.6	49.6
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	19.4	21.4	21.7	84.3	104.6	104.1	123.4	147.8	156.3
Combustion Turbine/Diesel	0.0	13.8	12.6	13.2	51.8	52.8	50.4	75.6	75.7	70.4
Nuclear Power	0.0	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	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.3	1.6	1.7	4.1	5.0	5.3	5.6	6.5	6.6
Distributed Generation[7]	0.0	1.6	1.8	1.8	10.6	10.7	10.3	16.3	16.9	16.3
Total	**0.0**	**44.3**	**42.4**	**42.4**	**191.6**	**199.8**	**193.5**	**297.4**	**301.5**	**299.2**
Cumulative Total Additions	**0.0**	**164.3**	**162.4**	**162.4**	**313.3**	**321.5**	**315.1**	**419.2**	**423.3**	**421.0**
Cumulative Retirements[10]										
Coal Steam	0.0	6.9	7.8	7.6	8.7	11.1	11.0	9.8	12.2	12.1
Other Fossil Steam[4]	0.0	43.3	44.6	44.6	49.4	57.8	57.2	50.2	58.6	58.5
Combined Cycle	0.0	1.2	1.1	0.7	1.2	1.1	0.7	1.2	1.3	0.9
Combustion Turbine/Diesel	0.0	5.6	7.6	7.5	8.5	10.9	10.8	11.4	11.8	12.3
Nuclear Power	0.0	2.8	2.8	2.8	3.8	3.8	3.8	3.8	3.8	3.8
Pumped Storage	0.0	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	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**60.0**	**64.0**	**63.4**	**71.7**	**84.9**	**83.7**	**76.5**	**87.8**	**87.7**

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

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.5	17.3	17.9	18.1	23.2	24.8	25.6	28.2	30.4	31.6
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Renewable Sources[6]	4.7	6.2	6.2	6.2	8.1	8.1	8.1	9.0	9.0	9.0
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.7**	**32.1**	**32.7**	**33.0**	**40.0**	**41.5**	**42.4**	**46.0**	**48.1**	**49.3**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	1.7	1.7	2.0	2.1	2.1
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	4.4	5.0	5.2	12.3	13.8	14.6	18.4	20.4	21.6
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.6	0.6	0.9	0.9	0.9

[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 4.3 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[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, 2001.
[10]Cumulative total retirements after December 31, 2001.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include 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.
[13]See Table C9 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C6. Natural Gas Supply and Disposition

(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Production										
Dry Gas Production[1]	19.45	21.68	21.78	21.87	25.50	25.58	25.62	26.44	26.62	26.77
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.86**	**4.92**	**4.96**	**6.84**	**7.43**	**7.58**	**8.07**	**8.79**	**8.82**
Canada	3.61	4.22	4.28	4.30	5.05	5.05	5.08	5.20	5.26	5.26
Mexico	-0.13	-0.20	-0.20	-0.20	0.17	0.27	0.27	0.58	0.60	0.61
Liquefied Natural Gas	0.26	0.84	0.84	0.86	1.62	2.10	2.23	2.29	2.93	2.96
Total Supply	**23.26**	**26.64**	**26.79**	**26.93**	**32.43**	**33.10**	**33.29**	**34.60**	**35.51**	**35.69**
Consumption by Sector										
Residential	4.81	5.48	5.47	5.47	5.94	5.94	5.94	6.21	6.18	6.17
Commercial	3.24	3.64	3.63	3.63	4.12	4.12	4.12	4.39	4.37	4.37
Industrial[3]	7.53	8.82	8.84	8.86	10.22	10.28	10.28	10.97	11.04	11.05
Electric Generators[4]	5.30	6.82	6.95	7.06	9.80	10.41	10.61	10.54	11.41	11.57
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.61	0.76	0.77	0.77	0.95	0.96	0.95	1.00	1.01	1.01
Lease and Plant Fuel[6]	1.17	1.34	1.35	1.35	1.61	1.61	1.61	1.69	1.69	1.70
Total	**22.67**	**26.92**	**27.07**	**27.21**	**32.74**	**33.41**	**33.61**	**34.91**	**35.82**	**35.99**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.28**	**-0.28**	**-0.28**	**-0.30**	**-0.31**	**-0.32**	**-0.31**	**-0.31**	**-0.30**

[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 consumption for combined heat and power, which produces electricity and other useful thermal energy.

[4]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.

[5]Compressed natural gas used as vehicle fuel.

[6]Represents natural gas used in the field gathering and processing plant machinery.

[7]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, 2001 values include net storage injections.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C7. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.88**	**23.89**	**23.90**	**25.04**	**25.04**	**24.99**	**26.18**	**26.21**	**26.23**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.64**	**5.64**	**5.64**	**5.43**	**5.43**	**5.43**	**5.33**	**5.32**	**5.33**
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.06	2.06	2.06	1.92	1.92	1.92
Lower 48 Offshore	1.71	2.52	2.52	2.52	2.14	2.14	2.14	2.24	2.23	2.23
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.72**	**17.73**	**17.73**	**15.46**	**15.44**	**15.44**	**15.11**	**15.08**	**15.09**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.42**	**3.43**	**3.44**	**3.67**	**3.66**	**3.68**	**3.97**	**4.10**	**4.15**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**21.68**	**21.78**	**21.87**	**25.50**	**25.58**	**25.62**	**26.44**	**26.62**	**26.77**
Lower 48 Onshore	13.72	15.75	15.74	15.82	17.52	17.76	17.73	17.85	18.04	18.19
Associated-Dissolved[4]	1.77	1.37	1.37	1.37	1.19	1.19	1.19	1.13	1.13	1.13
Non-Associated	11.94	14.38	14.38	14.45	16.33	16.56	16.54	16.72	16.91	17.06
Conventional	6.54	7.12	7.09	7.13	7.08	7.12	7.06	7.06	7.11	7.18
Unconventional	5.40	7.26	7.28	7.32	9.25	9.45	9.47	9.67	9.80	9.88
Lower 48 Offshore	5.30	5.45	5.56	5.58	5.58	5.43	5.50	5.73	5.73	5.73
Associated-Dissolved[4]	1.08	0.96	0.96	0.96	0.80	0.80	0.80	0.83	0.82	0.82
Non-Associated	4.22	4.49	4.60	4.62	4.78	4.63	4.70	4.91	4.91	4.91
Alaska	0.43	0.48	0.48	0.48	2.39	2.39	2.39	2.85	2.85	2.85
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**186.40**	**186.62**	**186.65**	**194.61**	**194.73**	**195.09**	**190.76**	**189.94**	**190.57**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.76**	**25.87**	**25.85**	**26.21**	**26.14**	**26.20**	**27.50**	**27.68**	**27.85**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001*, DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C8. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Production[1]										
Appalachia	443	420	394	414	407	366	423	420	357	430
Interior	147	155	129	144	147	96	121	158	99	129
West	548	666	700	639	800	848	687	875	936	728
East of the Mississippi	539	527	481	516	517	435	532	542	429	554
West of the Mississippi	599	713	743	681	837	875	698	911	964	732
Total	**1138**	**1240**	**1223**	**1197**	**1355**	**1311**	**1230**	**1453**	**1392**	**1287**
Net Imports										
Imports	20	20	20	20	25	25	25	28	28	28
Exports	49	34	34	33	29	29	29	24	27	26
Total	**-29**	**-14**	**-14**	**-14**	**-4**	**-4**	**-4**	**4**	**1**	**2**
Total Supply[2]	**1109**	**1227**	**1209**	**1184**	**1351**	**1307**	**1226**	**1457**	**1393**	**1288**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	67	67	67	70	70	70	71	71	71
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	20	20	20	18	18	18
Electric Generators[4]	957	1136	1119	1093	1262	1217	1137	1369	1305	1197
Total	**1050**	**1232**	**1214**	**1189**	**1357**	**1312**	**1232**	**1463**	**1400**	**1292**
Discrepancy and Stock Change[5]	**59**	**-5**	**-5**	**-5**	**-6**	**-5**	**-6**	**-7**	**-7**	**-3**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.06	14.67	15.68	14.23	13.29	15.66	14.22	13.06	16.24
(2001 dollars per million Btu)	0.83	0.73	0.72	0.75	0.70	0.66	0.74	0.70	0.66	0.77
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.83	30.05	29.84	30.31	28.37	27.49	28.13	27.91	26.88	27.76
Coke Plants	46.42	41.25	41.36	41.29	38.11	38.08	38.26	36.77	36.72	36.71
Electric Generators										
(2001 dollars per short ton)	25.05	23.71	23.99	24.49	22.37	22.38	23.89	22.17	22.26	24.33
(2001 dollars per million Btu)	1.25	1.17	1.19	1.20	1.12	1.13	1.15	1.11	1.13	1.16
Average	**26.05**	**24.40**	**24.66**	**25.16**	**22.91**	**22.89**	**24.36**	**22.63**	**22.68**	**24.69**
Exports[7]	36.97	32.68	32.73	32.90	30.90	30.70	31.20	30.40	29.80	29.68

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.
[2]Production plus net imports and 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 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C9. Coal Production by Region and Type
(Million Short Tons)

Supply Regions and Coal Types	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Northern Appalachia	**153.6**	**135.2**	**117.3**	**114.9**	**131.0**	**105.3**	**119.7**	**143.2**	**104.3**	**112.0**
Medium Sulfur (Premium)[1]	3.8	2.5	2.5	2.5	2.3	2.3	2.3	2.4	2.4	2.4
Low Sulfur (Bituminous)[2]	0.4	0.0	0.2	0.0	0.0	0.1	0.1	0.0	0.0	0.0
Medium Sulfur (Bituminous)[2]	75.2	67.1	59.5	56.7	62.6	61.2	62.1	70.6	62.4	67.6
High Sulfur (Bituminous)	63.6	54.2	45.5	46.1	54.6	32.0	45.5	58.8	29.8	38.8
High Sulfur (Gob)[3]	10.6	11.4	9.7	9.7	11.4	9.7	9.7	11.4	9.7	3.1
Central Appalachia	**267.0**	**264.5**	**257.8**	**277.8**	**259.6**	**246.5**	**285.0**	**261.3**	**239.6**	**301.0**
Medium Sulfur (Premium)[1]	38.9	31.9	32.0	31.6	27.1	27.1	27.1	24.2	24.2	24.1
Low Sulfur (Bituminous)	71.2	73.6	79.5	84.1	70.6	71.4	93.2	72.1	70.2	104.0
Medium Sulfur (Bituminous)	156.8	159.0	146.4	162.1	161.9	148.0	164.6	165.0	145.1	172.8
Southern Appalachia	**22.8**	**20.1**	**19.2**	**21.6**	**16.8**	**14.4**	**17.9**	**15.3**	**13.4**	**16.6**
Low Sulfur (Premium)[1]	6.7	6.0	6.1	6.0	4.9	4.9	4.8	4.2	4.2	4.1
Low Sulfur (Bituminous)	5.9	4.0	4.1	5.4	3.8	3.6	5.3	3.5	3.5	6.4
Medium Sulfur (Bituminous)	10.2	10.0	9.0	10.2	8.1	6.0	7.8	7.6	5.8	6.1
Eastern Interior	**96.0**	**107.4**	**86.5**	**101.9**	**110.0**	**69.1**	**109.7**	**122.4**	**71.4**	**124.7**
Medium Sulfur (Bituminous)	33.6	33.7	28.7	31.6	38.4	34.7	49.2	41.3	37.9	62.7
High Sulfur (Bituminous)	61.8	69.7	54.1	67.4	67.8	31.5	57.5	77.4	30.6	59.0
Medium Sulfur (Lignite)	0.6	4.1	3.7	2.9	3.8	2.9	2.9	3.7	2.9	2.9
Western Interior High Sulfur (Bituminous)	**2.4**	**2.5**	**1.6**	**1.2**	**2.0**	**0.5**	**0.5**	**1.8**	**0.4**	**0.4**
Gulf	**48.6**	**45.1**	**40.9**	**40.8**	**35.2**	**26.8**	**10.6**	**33.7**	**26.8**	**3.6**
Medium Sulfur (Lignite)	33.4	28.0	28.3	29.2	21.4	22.7	7.3	20.3	23.0	1.7
High Sulfur (Lignite)	15.2	17.1	12.6	11.6	13.9	4.1	3.4	13.4	3.8	1.9
Dakota Medium Sulfur (Lignite)	**30.8**	**31.6**	**30.9**	**30.9**	**33.5**	**19.9**	**19.8**	**33.6**	**20.1**	**20.0**
Powder/Green River	**407.5**	**511.4**	**531.7**	**469.1**	**641.9**	**702.5**	**498.4**	**705.5**	**790.2**	**514.6**
Low Sulfur (Bituminous)	0.0	1.6	1.6	1.6	1.3	1.5	0.8	0.8	1.1	1.4
Low Sulfur (Sub-Bituminous)	375.1	483.2	499.4	441.1	603.7	668.3	487.4	659.9	749.1	502.2
Medium Sulfur (Sub-Bituminous)	32.5	26.6	30.7	26.4	36.9	32.6	10.2	44.8	40.0	11.0
Rocky Mountain	**60.3**	**81.7**	**95.5**	**95.5**	**87.6**	**88.4**	**125.3**	**98.9**	**88.9**	**150.1**
Low Sulfur (Bituminous)	50.5	72.5	86.3	86.3	81.1	81.9	117.0	92.4	82.4	139.2
Low Sulfur (Sub-Bituminous)	9.8	9.2	9.2	9.2	6.5	6.5	8.3	6.5	6.5	11.0
Arizona/New Mexico	**43.0**	**34.8**	**35.8**	**37.4**	**30.8**	**30.8**	**37.1**	**30.8**	**30.8**	**37.5**
Low Sulfur (Bituminous)	20.9	16.3	17.2	18.8	14.2	14.2	20.5	14.2	14.2	20.9
Medium Sulfur (Bituminous)	0.7	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Medium Sulfur (Sub-bituminous)	21.5	11.5	11.5	11.5	9.5	9.5	9.5	9.5	9.5	9.5
Washington/Alaska Medium Sulfur (Sub-Bituminous)	**6.1**	**6.2**	**6.2**	**6.2**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**

Table C9. Coal Production by Region and Type (Continued)

(Million Short Tons)

Supply Regions and Coal Types	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Subtotals: All Regions										
Premium Metallurgical[1]	49.5	40.4	40.5	40.1	34.3	34.3	34.3	30.8	30.7	30.7
Bituminous	553.2	571.2	540.8	578.6	573.5	493.8	631.2	612.7	490.5	686.4
Sub-Bituminous	445.0	536.7	557.0	494.4	662.9	723.3	521.7	727.0	811.6	540.0
Lignite	90.6	92.1	85.1	84.3	83.9	59.2	43.0	82.4	59.5	29.6
Low Sulfur	540.5	666.4	703.5	652.6	786.1	852.4	737.4	853.6	931.2	789.2
Medium Sulfur	444.2	419.1	396.4	408.7	418.8	380.3	376.4	436.4	386.8	394.3
High Sulfur	153.6	154.9	123.5	136.0	149.7	77.8	116.5	162.9	74.2	103.2
Underground	380.2	405.4	387.3	407.2	420.0	364.9	459.5	452.8	366.5	505.7
Surface	758.1	835.0	836.1	790.1	934.7	945.7	770.8	1000.1	1025.8	780.9
U.S. Total	**1138.3**	**1240.4**	**1223.4**	**1197.3**	**1354.6**	**1310.6**	**1230.3**	**1452.9**	**1392.2**	**1286.7**

[1]"Premium" coal is used to make metallurgical coke.
[2]Includes Pennsylvania anthracite.
[3]Waste coal delivered to Independent Power Producers (IPP) that is not included in other Energy Information Administration coal production tables. The totals for this table include this waste coal tonnage.
Northern Appalachia: Pennsylvania, Maryland, Ohio, Northern West Virginia (Pennsylvania anthracite is included under low and medium sulfur bituminous).
Central Appalachia: Southern West Virginia, Virginia, Eastern Kentucky.
Southern Appalachia: Alabama, Tennessee.
Eastern Interior: Illinois, Indiana, Mississippi, Western Kentucky.
Western Interior (Bituminous only): Iowa, Missouri, Kansas, Oklahoma, Arkansas, Texas.
Gulf (Lignite only): Texas, Louisiana, Arkansas.
Dakota: North Dakota, Eastern Montana (Lignite only).
Powder/Green River: Wyoming, Montana (Sub-Bituminous and Bituminous)
Rocky Mountain: Colorado, Utah.
Sulfur Definitions:
Low Sulfur: 0 - 0.60 pounds of sulfur per million British thermal unit.
Medium Sulfur: 0.61 - 1.67 pounds of sulfur per million British thermal unit.
High Sulfur: Over 1.67 pounds of sulfur per million British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C10. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.10	78.66	78.66	78.66	78.65	78.65	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	3.81	3.90	3.91	5.46	5.70	5.73	5.94	6.21	6.20
Municipal Solid Waste[3]	3.25	3.99	3.99	3.99	4.32	4.38	4.38	4.39	4.39	4.39
Wood and Other Biomass[4]	1.80	2.09	2.09	2.09	2.24	2.20	2.20	2.36	2.20	2.20
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	8.13	8.39	8.40	10.15	10.85	11.09	10.98	11.76	11.87
Total	**90.62**	**97.22**	**97.56**	**97.58**	**101.57**	**102.53**	**102.80**	**103.19**	**104.06**	**104.17**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.90	300.89	300.89	300.07	300.06	300.05	300.36	300.35	300.34
Geothermal[2]	13.81	21.99	22.70	22.77	35.54	37.47	37.74	39.58	41.64	41.62
Municipal Solid Waste[3]	19.55	28.52	28.52	28.52	30.99	31.44	31.44	31.61	31.60	31.60
Wood and Other Biomass[4]	9.38	20.88	26.76	27.61	21.51	27.43	28.66	22.02	27.32	29.78
Dedicated Plants	7.67	12.44	12.32	12.19	13.41	12.87	12.81	14.09	12.92	13.08
Cofiring	1.71	8.44	14.43	15.41	8.10	14.56	15.86	7.94	14.40	16.70
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	22.55	23.47	23.49	29.65	32.19	33.02	32.68	35.53	35.92
Total	**262.85**	**395.86**	**403.35**	**404.29**	**419.31**	**430.14**	**432.48**	**428.11**	**438.30**	**441.12**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.92	5.91	5.91	7.79	7.80	7.80	8.74	8.74	8.74
Total	**4.69**	**6.21**	**6.20**	**6.20**	**8.07**	**8.08**	**8.08**	**9.03**	**9.02**	**9.02**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.62	0.62	0.62	0.96	0.96	0.96
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.71**	**1.71**	**1.71**	**2.05**	**2.05**	**2.05**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.51	37.45	37.46	48.42	48.46	48.44	53.98	53.96	53.94
Total	**31.13**	**39.66**	**39.61**	**39.61**	**50.57**	**50.61**	**50.59**	**56.13**	**56.12**	**56.09**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.32	1.33	1.33	2.02	2.03	2.03
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.56**	**5.57**	**5.57**	**6.25**	**6.26**	**6.26**

[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]Includes projections for energy crops after 2010.
[5]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Includes 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 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. 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: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C11. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.6	25.7	25.7	25.0	25.0	25.0
Natural Gas	71.1	81.1	81.0	81.0	88.0	87.9	87.9	91.9	91.4	91.4
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Electricity	215.1	245.7	241.0	239.5	271.6	263.2	259.2	289.5	277.6	273.1
Total	**313.8**	**354.8**	**350.0**	**348.5**	**385.6**	**377.1**	**373.1**	**406.7**	**394.3**	**389.8**
Commercial										
Petroleum	14.0	13.7	13.7	13.7	14.1	14.2	14.2	14.1	14.2	14.2
Natural Gas	48.0	53.8	53.8	53.8	61.0	61.0	61.0	65.0	64.7	64.7
Coal	2.3	2.4	2.4	2.4	2.7	2.7	2.7	2.8	2.8	2.8
Electricity	214.5	249.8	245.5	244.1	299.0	290.1	285.6	329.5	316.5	311.4
Total	**278.8**	**319.8**	**315.5**	**314.1**	**376.8**	**367.9**	**363.4**	**411.3**	**398.2**	**393.1**
Industrial[1]										
Petroleum	97.9	98.0	97.7	97.7	105.0	105.3	105.7	109.4	109.3	109.6
Natural Gas[2]	123.4	147.9	148.3	148.5	171.9	172.8	172.8	184.0	185.3	185.6
Coal	52.1	56.5	56.4	56.3	56.2	56.2	56.1	56.2	56.3	56.1
Electricity	178.1	197.7	194.6	193.3	225.6	219.3	216.0	243.0	233.6	229.6
Total	**451.5**	**500.0**	**497.0**	**495.9**	**558.7**	**553.6**	**550.7**	**592.6**	**584.4**	**580.9**
Transportation										
Petroleum[3]	501.4	611.4	610.7	610.6	737.6	737.4	737.0	802.6	802.1	801.7
Natural Gas[4]	9.2	12.1	12.2	12.3	15.5	15.6	15.5	16.4	16.6	16.6
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	3.9	4.6	4.6	4.6	6.0	5.8	5.8	6.9	6.7	6.6
Total	**514.5**	**628.2**	**627.6**	**627.5**	**759.1**	**758.8**	**758.3**	**826.0**	**825.4**	**824.8**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	750.7	749.8	749.7	882.4	882.6	882.6	951.1	950.6	950.4
Natural Gas	251.7	294.9	295.3	295.6	336.4	337.3	337.2	357.3	358.0	358.3
Coal	54.7	59.3	59.2	59.1	59.2	59.3	59.1	59.3	59.4	59.2
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	611.6	697.8	685.7	681.6	802.2	778.4	766.6	868.9	834.3	820.6
Total	**1558.6**	**1802.7**	**1790.0**	**1786.0**	**2080.2**	**2057.5**	**2045.5**	**2236.6**	**2202.3**	**2188.6**
Electric Generators[6]										
Petroleum	27.5	10.8	8.5	8.5	12.8	9.0	8.4	13.4	10.5	10.5
Natural Gas	77.7	100.0	102.0	103.7	143.8	152.8	155.6	154.7	167.4	169.8
Coal	506.4	587.0	575.3	569.4	645.6	616.6	602.6	700.8	656.3	640.3
Total	**611.6**	**697.8**	**685.7**	**681.6**	**802.2**	**778.4**	**766.6**	**868.9**	**834.3**	**820.6**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	761.5	758.3	758.2	895.2	891.5	891.0	964.5	961.1	961.0
Natural Gas	329.4	395.0	397.3	399.3	480.2	490.0	492.8	512.0	525.4	528.1
Coal	561.1	646.3	634.5	628.6	704.8	675.9	661.7	760.1	715.8	699.5
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1802.7**	**1790.0**	**1786.0**	**2080.2**	**2057.5**	**2045.5**	**2236.6**	**2202.3**	**2188.6**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.6**	**6.0**	**6.0**	**5.9**	**6.4**	**6.3**	**6.3**	**6.6**	**6.5**	**6.5**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Table C12. Emissions, Allowance Prices, and Emission Controls in the Electric Power Sector

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve	Reference	Clear Skies 2P	Clear Skies 3P No Safety Valve
Emissions										
Nitrogen Oxides (million tons)	4.75	3.93	2.06	2.04	4.05	1.73	1.71	4.11	1.74	1.73
Sulfur Dioxide (million tons)	10.64	9.66	6.03	5.82	8.95	4.43	4.41	8.95	4.21	4.04
From Coal	10.05	9.47	5.91	5.69	8.72	4.32	4.29	8.75	4.11	3.93
From Oil/Other	0.60	0.19	0.12	0.13	0.23	0.11	0.11	0.20	0.10	0.10
Mercury (tons)	49.49	52.56	44.52	26.00	53.43	43.33	18.70	54.33	44.73	15.00
Carbon Dioxide (million metric tons carbon equivalent)	611.57	697.82	685.73	681.56	802.16	778.38	766.63	868.91	834.32	820.64
Allowance Prices										
Nitrogen Oxides (2001 dollars per ton)										
Regional/Seasonal	0.00	4741.70	0.00	0.00	5550.48	0.00	0.00	6207.45	0.00	0.00
East/Annual	0.00	0.00	2607.56	2415.31	0.00	2472.62	2354.19	0.00	2601.57	2527.56
West/Annual	0.00	0.00	1692.37	1761.15	0.00	1811.41	1721.69	0.00	1895.14	1718.51
Sulfur Dioxide (2001 dollars per ton)	76.93	100.52	681.36	554.42	89.80	987.74	955.83	51.70	1210.92	1008.03
Mercury (thousand 2001 dollars per pound)	0.00	0.00	0.00	49.45	0.00	0.00	67.52	0.00	0.00	120.24
Carbon Dioxide (2001 dollars per million metric ton carbon equivalent)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)										
Scrubber[6]										
Planned	1.49	20.65	20.65	20.65	22.82	22.82	22.82	22.82	22.82	22.82
Unplanned	0.00	0.00	32.36	42.18	0.00	61.71	65.49	0.00	61.71	76.20
Total	1.49	20.65	53.01	62.84	22.82	84.53	88.31	22.82	84.53	99.02
Nitrogen Oxides Controls										
Combustion	0.00	16.01	24.95	25.19	17.45	31.00	31.02	17.83	31.48	31.13
SCR Post-combustion	0.00	79.20	137.48	138.12	83.24	168.57	170.78	84.52	169.96	175.36
SNCR Post-combustion	0.00	16.67	8.85	8.78	35.40	35.28	24.40	47.18	44.52	24.77
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs per million Btu)	540.47	666.41	703.46	652.60	786.14	852.44	737.39	853.64	931.20	789.15
Medium Sulfur	444.21	419.09	396.42	408.75	418.81	380.34	376.38	436.35	386.79	394.34
High Sulfur (> 1.67 lbs per million Btu)	153.63	154.89	123.52	135.99	149.68	77.79	116.51	162.92	74.25	103.18
Interregional Sulfur Dioxide Allowances										
Target (million tons)	9.48	8.95	4.50	4.50	8.95	3.00	3.00	8.95	3.00	3.00
Cumulative Banked Allowances	9.23	1.03	19.22	18.92	0.00	9.99	11.11	0.00	3.42	5.16
Coal Characteristics										
SO_2 Content (pounds per million Btu)	1.85	1.73	1.59	1.68	1.62	1.33	1.56	1.62	1.28	1.52
Mercury Content (lbs per trillion Btu)	7.50	7.25	7.02	7.05	7.04	6.75	6.75	6.99	6.67	6.44
ACI Controls (gigawatts)										
Spray Cooling	0.00	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	0.00	11.76	0.00	0.00	41.08	0.00	0.00	52.41
ACI Mercury Removal (tons)	**0.00**	**0.00**	**0.00**	**15.75**	**0.00**	**0.00**	**17.48**	**0.00**	**0.00**	**18.10**
Allowance Revenues (billion 2001 dollars)										
Nitrogen Oxides	0.00	2.24	5.04	4.76	2.63	3.89	3.70	2.94	4.09	3.91
Sulfur Dioxide	2.02	1.74	4.98	4.42	1.30	8.13	7.74	1.10	9.66	8.41
Mercury	0.00	0.00	0.00	3.07	0.00	0.00	3.71	0.00	0.00	4.37
Carbon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**2.02**	**3.98**	**10.02**	**12.26**	**3.92**	**12.02**	**15.16**	**4.03**	**13.75**	**16.69**

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 2001 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCS2P.D081103A, IMCS3PNS.D080503A.

Appendix D Tables:

Reference, Carper 2P, Carper 3P

Table D1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Production										
Crude Oil and Lease Condensate	12.29	11.93	11.94	11.94	11.50	11.50	11.53	11.29	11.29	11.31
Natural Gas Plant Liquids	2.65	3.14	3.17	3.17	3.59	3.62	3.60	3.71	3.73	3.72
Dry Natural Gas	19.97	22.26	22.48	22.47	26.18	26.37	26.25	27.15	27.30	27.18
Coal	23.97	25.56	24.72	24.90	27.53	26.41	26.41	29.48	28.35	28.32
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[1]	5.32	7.28	7.41	7.40	8.36	8.50	8.50	8.81	8.90	8.92
Other[2]	0.57	0.85	0.85	0.85	0.79	0.79	0.79	0.80	0.80	0.80
Total	**72.80**	**79.24**	**78.79**	**78.95**	**86.21**	**85.42**	**85.33**	**89.49**	**88.62**	**88.49**
Imports										
Crude Oil[3]	20.26	25.07	25.02	25.03	27.60	27.59	27.56	28.55	28.46	28.54
Petroleum Products[4]	5.04	6.34	6.18	6.16	11.68	11.47	11.48	14.86	14.79	14.68
Natural Gas	4.18	5.54	5.64	5.62	7.37	7.83	7.84	8.61	8.87	8.89
Other Imports[5]	0.73	0.94	0.97	0.97	0.99	0.99	0.98	0.95	0.95	0.95
Total	**30.21**	**37.89**	**37.81**	**37.78**	**47.63**	**47.88**	**47.86**	**52.96**	**53.07**	**53.07**
Exports										
Petroleum[6]	2.01	2.25	2.25	2.25	2.34	2.34	2.36	2.42	2.43	2.43
Natural Gas	0.37	0.56	0.56	0.56	0.37	0.37	0.36	0.36	0.36	0.35
Coal	1.27	0.87	0.86	0.85	0.74	0.74	0.74	0.61	0.60	0.64
Total	**3.64**	**3.67**	**3.67**	**3.66**	**3.46**	**3.45**	**3.46**	**3.39**	**3.38**	**3.42**
Discrepancy[7]	**2.08**	**0.22**	**0.16**	**0.30**	**0.22**	**0.27**	**0.20**	**0.20**	**0.41**	**0.18**
Consumption										
Petroleum Products[8]	38.46	44.48	44.29	44.28	52.20	52.00	51.99	56.18	56.02	56.01
Natural Gas	23.26	27.61	27.92	27.89	33.56	34.21	34.10	35.79	36.19	36.12
Coal	22.02	25.32	24.56	24.60	27.58	26.41	26.48	29.75	28.45	28.57
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[1]	5.32	7.28	7.41	7.40	8.36	8.50	8.50	8.81	8.90	8.92
Other[9]	0.21	0.33	0.37	0.37	0.21	0.20	0.20	0.08	0.09	0.08
Total	**97.29**	**113.24**	**112.77**	**112.77**	**130.17**	**129.57**	**129.53**	**138.87**	**137.90**	**137.96**
Net Imports - Petroleum	**23.29**	**29.16**	**28.94**	**28.94**	**36.93**	**36.71**	**36.69**	**40.99**	**40.83**	**40.79**
Prices (2001 dollars per unit)										
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.99	23.99	25.48	25.48	25.48	26.57	26.57	26.57
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.42	3.43	3.44	3.67	3.63	3.64	3.97	4.11	4.05
Coal Minemouth Price (dollars per ton)	17.59	15.06	14.92	15.25	14.23	13.46	15.44	14.22	13.02	15.41
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.6	6.7	6.8	6.8	6.9	6.8	6.9	7.0

[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 D18 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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Energy Consumption										
Residential										
Distillate Fuel	0.91	0.91	0.91	0.91	0.84	0.84	0.84	0.81	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.06	0.06	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.46	0.46	0.46	0.46	0.46	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.36	1.36	1.36	1.33	1.33	1.33
Natural Gas	4.94	5.63	5.63	5.63	6.11	6.11	6.11	6.38	6.36	6.36
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.41	0.41	0.41	0.40	0.40	0.40
Electricity	4.10	4.93	4.89	4.89	5.59	5.56	5.54	5.94	5.90	5.90
Delivered Energy	**10.94**	**12.44**	**12.40**	**12.40**	**13.48**	**13.45**	**13.44**	**14.07**	**14.01**	**14.00**
Electricity Related Losses	9.15	10.41	10.26	10.27	11.13	10.91	10.91	11.51	11.20	11.20
Total	**20.08**	**22.85**	**22.66**	**22.67**	**24.61**	**24.36**	**24.35**	**25.58**	**25.21**	**25.21**
Commercial										
Distillate Fuel	0.46	0.51	0.51	0.51	0.52	0.53	0.53	0.52	0.53	0.53
Residual Fuel	0.09	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.70	0.70	0.72	0.73	0.73	0.72	0.73	0.73
Natural Gas	3.33	3.74	3.73	3.74	4.24	4.24	4.24	4.51	4.50	4.50
Coal	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	5.01	4.98	4.98	6.15	6.13	6.11	6.76	6.73	6.72
Delivered Energy	**8.32**	**9.65**	**9.61**	**9.62**	**11.32**	**11.31**	**11.28**	**12.21**	**12.17**	**12.16**
Electricity Related Losses	9.12	10.58	10.45	10.45	12.26	12.03	12.02	13.10	12.77	12.77
Total	**17.44**	**20.23**	**20.06**	**20.07**	**23.58**	**23.34**	**23.31**	**25.31**	**24.95**	**24.93**
Industrial[4]										
Distillate Fuel	1.13	1.21	1.21	1.21	1.36	1.35	1.35	1.44	1.44	1.44
Liquefied Petroleum Gas	2.10	2.55	2.55	2.55	3.05	3.05	3.04	3.29	3.30	3.28
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	0.23	0.19	0.19	0.19	0.19	0.19	0.19	0.20	0.20	0.20
Motor Gasoline[2]	0.15	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.27	4.26	4.26	4.45	4.48	4.47	4.57	4.58	4.58
Petroleum Subtotal	8.79	9.82	9.81	9.80	10.93	10.96	10.94	11.52	11.53	11.51
Natural Gas	7.74	9.07	9.08	9.10	10.50	10.52	10.60	11.28	11.31	11.42
Lease and Plant Fuel[6]	1.20	1.38	1.39	1.39	1.65	1.66	1.66	1.73	1.74	1.73
Natural Gas Subtotal	8.94	10.45	10.47	10.48	12.15	12.18	12.25	13.01	13.05	13.15
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.42	1.45	1.46	1.45	1.51	1.51	1.51	1.54	1.54	1.54
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.16	2.23	2.23	2.22	2.22	2.22	2.21	2.22	2.22	2.22
Renewable Energy[7]	1.82	2.22	2.22	2.22	2.77	2.77	2.77	3.05	3.05	3.05
Electricity	3.39	3.96	3.95	3.94	4.64	4.63	4.61	4.99	4.96	4.95
Delivered Energy	**25.10**	**28.68**	**28.67**	**28.67**	**32.71**	**32.77**	**32.79**	**34.79**	**34.80**	**34.89**
Electricity Related Losses	7.57	8.37	8.29	8.28	9.25	9.08	9.07	9.66	9.42	9.41
Total	**32.67**	**37.05**	**36.96**	**36.95**	**41.96**	**41.85**	**41.86**	**44.45**	**44.22**	**44.30**

Table D2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Transportation										
Distillate Fuel[8]	5.44	7.09	7.07	7.07	8.68	8.68	8.67	9.55	9.54	9.54
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.10	5.67	5.67	5.68
Motor Gasoline[2]	16.26	19.81	19.79	19.79	23.57	23.56	23.56	25.48	25.47	25.47
Residual Fuel	0.84	0.83	0.83	0.83	0.86	0.86	0.86	0.87	0.87	0.87
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.07	0.07	0.07	0.09	0.08	0.09
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.97	31.94	31.93	38.57	38.57	38.55	41.97	41.96	41.96
Pipeline Fuel Natural Gas	0.63	0.78	0.80	0.80	0.98	0.99	0.99	1.03	1.04	1.04
Compressed Natural Gas	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Renewable Energy (E85)[11]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.09	0.12	0.12	0.12	0.14	0.14	0.14
Delivered Energy	**26.94**	**32.91**	**32.89**	**32.88**	**39.78**	**39.78**	**39.76**	**43.26**	**43.25**	**43.25**
Electricity Related Losses	0.17	0.20	0.20	0.20	0.24	0.24	0.24	0.27	0.27	0.27
Total	**27.10**	**33.11**	**33.08**	**33.08**	**40.02**	**40.02**	**40.00**	**43.53**	**43.52**	**43.52**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.94	9.73	9.71	9.71	11.40	11.40	11.39	12.32	12.31	12.32
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.10	5.67	5.67	5.68
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.68	3.68	3.67	3.94	3.94	3.92
Motor Gasoline[2]	16.46	20.01	19.99	19.99	23.79	23.78	23.77	25.71	25.70	25.70
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	1.15	1.06	1.06	1.06	1.10	1.10	1.10	1.12	1.11	1.12
Other Petroleum[12]	4.24	4.51	4.50	4.50	4.73	4.76	4.75	4.87	4.88	4.87
Petroleum Subtotal	37.21	43.96	43.91	43.90	51.59	51.62	51.59	55.54	55.54	55.53
Natural Gas	16.02	18.50	18.50	18.52	20.95	20.97	21.04	22.28	22.28	22.39
Lease and Plant Fuel Plant[6]	1.20	1.38	1.39	1.39	1.65	1.66	1.66	1.73	1.74	1.73
Pipeline Natural Gas	0.63	0.78	0.80	0.80	0.98	0.99	0.99	1.03	1.04	1.04
Natural Gas Subtotal	17.86	20.66	20.68	20.71	23.58	23.61	23.68	25.04	25.05	25.16
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	1.53	1.56	1.57	1.56	1.63	1.63	1.62	1.66	1.66	1.66
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	2.27	2.34	2.34	2.33	2.33	2.34	2.33	2.34	2.34	2.34
Renewable Energy[13]	2.31	2.74	2.73	2.73	3.29	3.29	3.29	3.57	3.57	3.57
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	13.99	13.91	13.90	16.50	16.45	16.39	17.84	17.74	17.72
Delivered Energy	**71.29**	**83.68**	**83.57**	**83.57**	**97.29**	**97.31**	**97.27**	**104.33**	**104.24**	**104.31**
Electricity Related Losses	26.00	29.56	29.20	29.20	32.88	32.26	32.25	34.54	33.66	33.65
Total	**97.29**	**113.24**	**112.77**	**112.77**	**130.17**	**129.57**	**129.53**	**138.87**	**137.90**	**137.96**
Electric Power[14]										
Distillate Fuel	0.17	0.10	0.10	0.09	0.11	0.10	0.12	0.18	0.20	0.19
Residual Fuel	1.08	0.41	0.28	0.29	0.50	0.28	0.29	0.47	0.29	0.29
Petroleum Subtotal	1.25	0.51	0.38	0.38	0.61	0.38	0.41	0.64	0.49	0.49
Natural Gas	5.40	6.95	7.24	7.19	9.98	10.60	10.42	10.75	11.13	10.96
Steam Coal	19.75	22.99	22.23	22.27	25.25	24.07	24.15	27.41	26.11	26.23
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[15]	3.01	4.55	4.68	4.67	5.08	5.21	5.22	5.25	5.34	5.35
Electricity Imports	0.21	0.33	0.37	0.37	0.21	0.20	0.20	0.08	0.09	0.08
Total	**37.65**	**43.55**	**43.11**	**43.10**	**49.38**	**48.71**	**48.64**	**52.38**	**51.40**	**51.36**

Table D2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Total Energy Consumption										
Distillate Fuel	8.10	9.84	9.82	9.80	11.51	11.50	11.50	12.49	12.51	12.51
Kerosene	0.15	0.12	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	5.09	5.09	5.10	5.67	5.67	5.68
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.68	3.68	3.67	3.94	3.94	3.92
Motor Gasoline[2]	16.46	20.01	19.99	19.99	23.79	23.78	23.77	25.71	25.70	25.70
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.70	1.70	1.70	1.82	1.82	1.82
Residual Fuel	2.23	1.47	1.34	1.35	1.60	1.38	1.39	1.58	1.40	1.41
Other Petroleum[12]	4.24	4.51	4.50	4.50	4.73	4.76	4.75	4.87	4.88	4.87
Petroleum Subtotal	38.46	44.48	44.29	44.28	52.20	52.00	51.99	56.18	56.02	56.01
Natural Gas	21.42	25.45	25.74	25.71	30.93	31.56	31.46	33.03	33.41	33.35
Lease and Plant Fuel[6]	1.20	1.38	1.39	1.39	1.65	1.66	1.66	1.73	1.74	1.73
Pipeline Natural Gas	0.63	0.78	0.80	0.80	0.98	0.99	0.99	1.03	1.04	1.04
Natural Gas Subtotal	23.26	27.61	27.92	27.89	33.56	34.21	34.10	35.79	36.19	36.12
Metallurgical Coal	0.72	0.66	0.66	0.66	0.55	0.55	0.55	0.50	0.50	0.50
Steam Coal	21.28	24.55	23.79	23.83	26.88	25.70	25.77	29.07	27.77	27.89
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.16	0.16	0.16	0.18	0.18	0.18
Coal Subtotal	22.02	25.32	24.56	24.60	27.58	26.41	26.48	29.75	28.45	28.57
Nuclear Power	8.03	8.22	8.22	8.22	8.25	8.25	8.25	8.25	8.25	8.25
Renewable Energy[16]	5.32	7.28	7.41	7.40	8.36	8.50	8.50	8.81	8.90	8.92
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.33	0.37	0.37	0.21	0.20	0.20	0.08	0.09	0.08
Total	**97.29**	**113.24**	**112.77**	**112.77**	**130.17**	**129.57**	**129.53**	**138.87**	**137.90**	**137.96**
Energy Use and Related Statistics										
Delivered Energy Use	71.29	83.68	83.57	83.57	97.29	97.31	97.27	104.33	104.24	104.31
Total Energy Use	97.29	113.24	112.77	112.77	130.17	129.57	129.53	138.87	137.90	137.96
Population (millions)	278.18	300.24	300.24	300.24	325.32	325.32	325.32	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12254	12242	12239	16448	16458	16453	18914	18914	18924
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.7	1784.1	1784.3	2080.2	2055.9	2053.2	2236.6	2208.0	2205.5

[1]Includes wood used for residential heating. See Table D18 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 D18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[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 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[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 2001 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: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D3. Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Residential	**15.80**	**14.02**	**14.28**	**14.33**	**14.67**	**14.75**	**14.83**	**14.99**	**15.20**	**15.27**
Primary Energy[1]	9.73	8.08	8.09	8.10	8.30	8.28	8.28	8.59	8.72	8.68
Petroleum Products[2]	10.85	10.02	10.01	10.02	10.92	10.92	10.90	11.23	11.24	11.23
Distillate Fuel	8.99	7.99	7.99	7.99	8.72	8.72	8.72	8.92	8.92	8.93
Liquefied Petroleum Gas	14.84	14.35	14.33	14.34	15.27	15.27	15.22	15.58	15.62	15.57
Natural Gas	9.41	7.60	7.61	7.62	7.73	7.71	7.71	8.05	8.21	8.17
Electricity	25.36	22.58	23.27	23.38	23.22	23.47	23.69	23.31	23.65	23.86
Commercial	**15.50**	**13.49**	**13.85**	**13.89**	**14.79**	**14.80**	**14.95**	**15.20**	**15.38**	**15.45**
Primary Energy[1]	7.81	6.45	6.46	6.47	6.75	6.73	6.73	7.07	7.20	7.16
Petroleum Products[2]	7.27	6.77	6.77	6.77	7.52	7.50	7.51	7.81	7.80	7.81
Distillate Fuel	6.40	5.66	5.67	5.67	6.46	6.46	6.47	6.75	6.74	6.76
Residual Fuel	3.46	4.01	4.00	4.00	4.24	4.20	4.21	4.40	4.36	4.37
Natural Gas	8.09	6.52	6.52	6.54	6.75	6.73	6.73	7.09	7.24	7.19
Electricity	23.27	19.88	20.59	20.65	21.42	21.47	21.78	21.62	21.87	22.02
Industrial[3]	**7.11**	**6.42**	**6.49**	**6.51**	**7.02**	**7.02**	**7.05**	**7.31**	**7.38**	**7.37**
Primary Energy	5.83	5.19	5.19	5.20	5.71	5.70	5.69	6.00	6.07	6.03
Petroleum Products[2]	7.72	7.07	7.06	7.07	7.83	7.83	7.82	8.15	8.17	8.15
Distillate Fuel	6.55	5.74	5.75	5.75	6.73	6.72	6.74	7.18	7.18	7.19
Liquefied Petroleum Gas	12.34	9.92	9.91	9.92	10.83	10.83	10.81	11.14	11.18	11.14
Residual Fuel	3.28	3.72	3.70	3.70	3.95	3.92	3.92	4.11	4.08	4.09
Natural Gas[4]	4.87	4.04	4.05	4.06	4.36	4.34	4.34	4.66	4.79	4.75
Metallurgical Coal	1.69	1.50	1.50	1.50	1.39	1.39	1.40	1.34	1.34	1.34
Steam Coal	1.46	1.38	1.37	1.38	1.31	1.27	1.31	1.29	1.25	1.29
Electricity	14.13	12.95	13.41	13.47	13.67	13.74	13.96	13.78	13.93	14.09
Transportation	**10.28**	**10.20**	**10.23**	**10.23**	**10.37**	**10.37**	**10.36**	**10.83**	**10.81**	**10.83**
Primary Energy	10.25	10.18	10.20	10.20	10.34	10.34	10.33	10.80	10.79	10.80
Petroleum Products[2]	10.25	10.18	10.20	10.20	10.35	10.35	10.34	10.81	10.79	10.81
Distillate Fuel[5]	10.05	10.19	10.19	10.19	10.27	10.27	10.23	10.67	10.65	10.66
Jet Fuel[6]	6.20	5.64	5.65	5.65	6.34	6.34	6.34	6.72	6.73	6.72
Motor Gasoline[7]	11.57	11.43	11.46	11.46	11.54	11.54	11.54	12.07	12.05	12.07
Residual Fuel	3.90	3.57	3.56	3.56	3.78	3.77	3.77	3.95	3.94	3.94
Liquefied Petroleum Gas[8]	16.93	15.52	15.47	15.50	16.01	16.02	15.94	16.04	16.20	16.10
Natural Gas[9]	7.65	7.22	7.24	7.25	7.71	7.69	7.69	8.11	8.26	8.22
Ethanol (E85)[10]	17.72	21.29	21.33	21.33	22.85	22.86	22.86	23.57	23.62	23.50
Electricity	21.87	19.18	19.74	19.83	18.72	18.83	19.04	18.11	18.37	18.54
Average End-Use Energy	**10.74**	**9.99**	**10.10**	**10.11**	**10.50**	**10.51**	**10.54**	**10.88**	**10.94**	**10.95**
Primary Energy	8.52	8.07	8.08	8.08	8.44	8.43	8.42	8.85	8.88	8.87
Electricity	21.33	18.86	19.49	19.57	19.83	19.95	20.20	19.96	20.21	20.39
Electric Power[11]										
Fossil Fuel Average	2.14	1.85	1.90	1.90	2.07	2.15	2.14	2.15	2.28	2.26
Petroleum Products	4.73	4.28	4.44	4.39	4.58	4.90	4.91	4.94	5.30	5.27
Distillate Fuel	6.20	5.12	5.14	5.13	6.02	6.00	5.96	6.19	6.10	6.12
Residual Fuel	4.50	4.07	4.18	4.15	4.26	4.52	4.49	4.47	4.73	4.71
Natural Gas	4.78	3.93	3.96	3.97	4.32	4.34	4.33	4.65	4.83	4.78
Steam Coal	1.25	1.17	1.19	1.19	1.12	1.14	1.15	1.11	1.14	1.15

Table D3. Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Average Price to All Users[12]										
Petroleum Products[2]	9.54	9.44	9.47	9.47	9.79	9.82	9.80	10.23	10.24	10.24
Distillate Fuel	9.16	9.14	9.14	9.15	9.52	9.53	9.50	9.92	9.91	9.91
Jet Fuel	6.20	5.64	5.65	5.65	6.34	6.34	6.34	6.72	6.73	6.72
Liquefied Petroleum Gas	12.85	10.75	10.73	10.74	11.56	11.56	11.53	11.83	11.88	11.84
Motor Gasoline[7]	11.57	11.43	11.46	11.46	11.54	11.54	11.54	12.07	12.05	12.07
Residual Fuel	4.11	3.74	3.72	3.72	3.96	3.96	3.96	4.13	4.14	4.13
Natural Gas	6.40	5.17	5.17	5.18	5.35	5.32	5.32	5.66	5.80	5.75
Coal	1.26	1.19	1.20	1.20	1.13	1.15	1.16	1.12	1.14	1.16
Ethanol (E85)[10]	17.72	21.29	21.33	21.33	22.85	22.86	22.86	23.57	23.62	23.50
Electricity	21.33	18.86	19.49	19.57	19.83	19.95	20.20	19.96	20.21	20.39
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)										
Residential	166.71	168.69	171.22	171.82	191.80	192.48	193.31	204.81	206.74	207.64
Commercial	127.27	128.81	131.72	132.12	165.91	165.80	167.15	183.97	185.59	186.24
Industrial	135.32	138.54	140.16	140.46	173.29	173.43	174.31	192.57	194.57	195.00
Transportation	270.40	327.78	328.12	328.05	402.17	402.15	401.59	457.13	456.41	456.93
Total Non-Renewable Expenditures	699.70	763.82	771.22	772.45	933.17	933.86	936.36	1038.49	1043.31	1045.81
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.10	0.10	0.10	0.13	0.13	0.13
Total Expenditures	**699.71**	**763.87**	**771.27**	**772.50**	**933.27**	**933.96**	**936.45**	**1038.62**	**1043.44**	**1045.93**

[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 combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price 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. Price includes estimated motor vehicle fuel taxes.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D4. Electricity Supply, Disposition, Prices, and Emissions

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1848	2216	2135	2143	2472	2349	2368	2726	2622	2642
Petroleum	113	44	31	31	53	30	30	58	45	44
Natural Gas[3]	411	677	726	724	1140	1259	1217	1289	1366	1337
Nuclear Power	769	787	787	787	790	790	790	790	790	790
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	392	403	403	415	426	427	424	432	433
Distributed Generation (Natural Gas)	0	1	1	1	5	5	5	7	8	8
Non-Utility Generation for Own Use	-21	-24	-24	-23	-24	-24	-23	-24	-24	-23
Total	**3370**	**4091**	**4057**	**4066**	**4850**	**4835**	**4813**	**5270**	**5237**	**5230**
Combined Heat and Power[5]										
Coal	33	33	31	23	33	31	23	33	31	23
Petroleum	7	4	4	4	4	4	4	3	4	4
Natural Gas	124	180	180	176	174	167	173	164	158	161
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-18	-17	-18	-17	-17	-18	-17	-17
Total	**162**	**203**	**202**	**190**	**197**	**188**	**187**	**187**	**179**	**175**
Net Available to the Grid	**3532**	**4294**	**4259**	**4255**	**5047**	**5022**	**5000**	**5457**	**5416**	**5405**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	23	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6	6
Natural Gas	83	107	110	113	151	156	166	187	195	207
Other Gaseous Fuels[7]	6	7	7	7	7	7	7	8	8	8
Renewable Sources[4]	31	40	40	40	51	51	51	56	56	56
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**160**	**194**	**197**	**200**	**249**	**255**	**264**	**292**	**300**	**312**
Other End-Use Generators[9]	4	5	5	5	6	6	6	6	6	6
Generation for Own Use	-137	-155	-157	-158	-188	-192	-197	-215	-220	-227
Total Sales to the Grid	**27**	**44**	**45**	**46**	**66**	**69**	**73**	**83**	**86**	**91**
Net Imports	**20**	**32**	**36**	**36**	**20**	**20**	**20**	**8**	**8**	**8**
Electricity Sales by Sector										
Residential	1201	1444	1432	1432	1637	1630	1625	1742	1730	1729
Commercial	1197	1468	1458	1458	1803	1798	1790	1982	1973	1970
Industrial	994	1162	1158	1156	1360	1357	1351	1462	1455	1452
Transportation	22	27	27	27	36	36	36	41	41	41
Total	**3414**	**4100**	**4076**	**4074**	**4836**	**4821**	**4803**	**5228**	**5199**	**5193**
End-Use Prices[10] **(2001 cents per kilowatthour)**										
Residential	8.7	7.7	7.9	8.0	7.9	8.0	8.1	8.0	8.1	8.1
Commercial	7.9	6.8	7.0	7.0	7.3	7.3	7.4	7.4	7.5	7.5
Industrial	4.8	4.4	4.6	4.6	4.7	4.7	4.8	4.7	4.8	4.8
Transportation	7.5	6.5	6.7	6.8	6.4	6.4	6.5	6.2	6.3	6.3
All Sectors Average	**7.3**	**6.4**	**6.6**	**6.7**	**6.8**	**6.8**	**6.9**	**6.8**	**6.9**	**7.0**
Prices by Service Category[10] **(2001 cents per kilowatthour)**										
Generation	4.7	3.9	4.1	4.2	4.3	4.3	4.4	4.3	4.4	4.5
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Distribution	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9	1.9	1.9

Table D4. Electricity Supply, Disposition, Prices, and Emissions (Continued)

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Emissions										
Sulfur Dioxide (million tons)	10.64	9.66	5.20	5.01	8.95	3.82	3.85	8.95	3.30	3.51
Nitrogen Oxide (million tons)	4.75	3.93	1.81	1.84	4.05	1.70	1.72	4.11	1.72	1.72
Mercury (tons)	49.49	52.56	41.76	18.15	53.43	42.24	9.99	54.33	44.07	10.00

[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.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include 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.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: 2001 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 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run IMBASE.D080503A. **Projections**: EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Electric PowerSector[2]										
Power Only[3]										
Coal Steam	305.3	306.8	302.0	302.2	337.5	326.2	328.8	372.1	362.5	365.6
Other Fossil Steam[4]	133.8	89.0	76.6	76.8	82.9	72.5	73.1	82.1	71.3	72.5
Combined Cycle	43.2	135.2	143.0	143.1	200.1	224.4	214.7	239.2	256.8	253.0
Combustion Turbine/Diesel	97.6	136.8	133.0	133.9	171.9	167.0	169.2	192.8	189.5	190.5
Nuclear Power[5]	98.2	98.3	98.3	98.3	98.6	98.6	98.6	98.6	98.6	98.6
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	97.0	98.6	98.6	101.3	102.6	102.6	102.9	103.5	103.7
Distributed Generation[7]	0.0	1.6	1.5	1.5	10.6	11.5	11.4	16.3	17.5	17.4
Total	**788.3**	**885.1**	**873.4**	**874.8**	**1023.5**	**1023.3**	**1019.1**	**1124.7**	**1120.3**	**1121.9**
Combined Heat and Power[8]										
Coal Steam	5.2	5.1	4.6	3.1	5.1	4.6	3.1	5.1	4.6	3.1
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.7**	**44.2**	**42.7**	**44.7**	**44.2**	**42.7**	**44.7**	**44.2**	**42.7**
Total Electric Power Industry	**822.0**	**929.8**	**917.6**	**917.5**	**1068.3**	**1067.6**	**1061.7**	**1169.4**	**1164.5**	**1164.6**
Cumulative Planned Additions[9]										
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	6.5	6.5	6.5	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**121.7**	**121.7**	**121.7**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	8.2	4.9	5.9	40.8	32.5	34.3	76.5	69.9	72.2
Other Fossil Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	19.4	27.4	27.8	84.3	108.9	99.4	123.4	141.2	137.9
Combustion Turbine/Diesel	0.0	13.8	13.0	13.7	51.8	50.4	52.3	75.6	73.4	74.4
Nuclear Power	0.0	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	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources[6]	0.0	1.3	2.9	2.9	4.1	5.4	5.4	5.6	6.1	6.4
Distributed Generation[7]	0.0	1.6	1.5	1.5	10.6	11.5	11.4	16.3	17.5	17.4
Total	**0.0**	**44.3**	**49.8**	**51.7**	**191.6**	**208.5**	**202.8**	**297.4**	**308.2**	**308.3**
Cumulative Total Additions	**0.0**	**164.3**	**169.8**	**171.7**	**313.3**	**330.2**	**324.5**	**419.2**	**430.0**	**430.0**
Cumulative Retirements[10]										
Coal Steam	0.0	6.9	8.8	11.1	8.7	12.2	13.0	9.8	13.3	14.1
Other Fossil Steam[4]	0.0	43.3	55.7	55.5	49.4	59.8	59.1	50.2	61.0	59.8
Combined Cycle	0.0	1.2	1.5	1.7	1.2	1.5	1.7	1.2	1.5	1.9
Combustion Turbine/Diesel	0.0	5.6	8.7	8.4	8.5	12.0	11.7	11.4	12.5	12.5
Nuclear Power	0.0	2.8	2.8	2.8	3.8	3.8	3.8	3.8	3.8	3.8
Pumped Storage	0.0	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	0.0
Renewable Sources[6]	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**60.0**	**77.6**	**79.7**	**71.7**	**89.4**	**89.5**	**76.5**	**92.2**	**92.2**

Table D5. Electricity Generating Capacity (Continued)

(Gigawatts)

Net Summer Capacity[1]	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.5	17.3	17.7	18.0	23.2	24.0	25.3	28.2	29.3	31.0
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3	2.3
Renewable Sources[6]	4.7	6.2	6.2	6.2	8.1	8.1	8.1	9.0	9.0	9.0
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.7**	**32.1**	**32.5**	**32.8**	**40.0**	**40.7**	**42.1**	**46.0**	**47.1**	**48.8**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.7	1.7	1.7	2.0	2.1	2.1
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	4.4	4.8	5.1	12.3	13.0	14.3	18.4	19.4	21.0
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.6	0.6	0.6	0.9	0.9	0.9

[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 4.3 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[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, 2001.
[10]Cumulative total retirements after December 31, 2001.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include 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.
[13]See Table D9 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D6. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Production										
Dry Gas Production[1]	19.45	21.68	21.89	21.88	25.50	25.67	25.56	26.44	26.59	26.47
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.86**	**4.96**	**4.94**	**6.84**	**7.30**	**7.31**	**8.07**	**8.32**	**8.35**
Canada	3.61	4.22	4.30	4.29	5.05	5.05	5.03	5.20	5.26	5.25
Mexico	-0.13	-0.20	-0.20	-0.20	0.17	0.27	0.27	0.58	0.60	0.60
Liquefied Natural Gas	0.26	0.84	0.87	0.86	1.62	1.99	2.01	2.29	2.47	2.50
Total Supply	**23.26**	**26.64**	**26.95**	**26.92**	**32.43**	**33.07**	**32.96**	**34.60**	**35.00**	**34.91**
Consumption by Sector										
Residential	4.81	5.48	5.47	5.48	5.94	5.94	5.94	6.21	6.19	6.19
Commercial	3.24	3.64	3.63	3.63	4.12	4.12	4.12	4.39	4.38	4.38
Industrial[3]	7.53	8.82	8.83	8.85	10.22	10.24	10.31	10.97	11.00	11.11
Electric Generators[4]	5.30	6.82	7.10	7.05	9.80	10.40	10.22	10.54	10.92	10.76
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.61	0.76	0.78	0.78	0.95	0.96	0.96	1.00	1.01	1.01
Lease and Plant Fuel[6]	1.17	1.34	1.35	1.35	1.61	1.62	1.61	1.69	1.69	1.69
Total	**22.67**	**26.92**	**27.22**	**27.20**	**32.74**	**33.37**	**33.27**	**34.91**	**35.30**	**35.23**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.28**	**-0.28**	**-0.28**	**-0.30**	**-0.30**	**-0.31**	**-0.31**	**-0.30**	**-0.32**

[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 consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]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.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]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, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D7. Oil and Gas Supply

Production and Supply	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Crude Oil										
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.88**	**23.89**	**23.89**	**25.04**	**25.00**	**25.04**	**26.18**	**26.24**	**26.20**
Production (million barrels per day)[2]										
U.S. Total	**5.80**	**5.64**	**5.64**	**5.64**	**5.43**	**5.43**	**5.45**	**5.33**	**5.33**	**5.34**
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.06	2.06	2.06	1.92	1.92	1.92
Lower 48 Offshore	1.71	2.52	2.52	2.52	2.14	2.14	2.15	2.24	2.24	2.25
Alaska	0.97	0.64	0.64	0.64	1.23	1.23	1.23	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.72**	**17.74**	**17.72**	**15.46**	**15.45**	**15.51**	**15.11**	**15.11**	**15.13**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.42**	**3.43**	**3.44**	**3.67**	**3.63**	**3.64**	**3.97**	**4.11**	**4.05**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.45**	**21.68**	**21.89**	**21.88**	**25.50**	**25.68**	**25.56**	**26.44**	**26.59**	**26.47**
Lower 48 Onshore	13.72	15.75	15.85	15.93	17.52	17.77	17.69	17.85	18.00	17.91
Associated-Dissolved[4]	1.77	1.37	1.37	1.37	1.19	1.19	1.19	1.13	1.13	1.13
Non-Associated	11.94	14.38	14.48	14.57	16.33	16.57	16.49	16.72	16.87	16.77
Conventional	6.54	7.12	7.10	7.14	7.08	7.10	7.07	7.06	7.15	7.09
Unconventional	5.40	7.26	7.39	7.42	9.25	9.47	9.42	9.67	9.72	9.69
Lower 48 Offshore	5.30	5.45	5.57	5.47	5.58	5.52	5.48	5.73	5.74	5.71
Associated-Dissolved[4]	1.08	0.96	0.96	0.96	0.80	0.80	0.80	0.83	0.83	0.83
Non-Associated	4.22	4.49	4.60	4.51	4.78	4.72	4.68	4.91	4.91	4.89
Alaska	0.43	0.48	0.48	0.48	2.39	2.39	2.39	2.85	2.85	2.85
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**186.40**	**186.13**	**185.47**	**194.61**	**194.11**	**194.17**	**190.76**	**189.90**	**189.89**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.76**	**25.79**	**25.70**	**26.21**	**26.13**	**26.17**	**27.50**	**27.86**	**27.53**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001*, DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D8. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Production[1]										
Appalachia	443	420	408	422	407	373	432	420	366	438
Interior	147	155	124	131	147	98	128	158	70	134
West	548	666	666	649	800	837	702	875	991	784
East of the Mississippi	539	527	490	511	517	444	539	542	413	557
West of the Mississippi	599	713	708	691	837	865	723	911	1013	799
Total	**1138**	**1240**	**1198**	**1202**	**1355**	**1309**	**1262**	**1453**	**1426**	**1356**
Net Imports										
Imports	20	20	20	20	25	25	25	28	28	28
Exports	49	34	33	33	29	29	29	24	23	25
Total	**-29**	**-14**	**-13**	**-13**	**-4**	**-4**	**-4**	**4**	**4**	**2**
Total Supply[2]	**1109**	**1227**	**1185**	**1188**	**1351**	**1305**	**1258**	**1457**	**1430**	**1358**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	67	67	67	70	70	70	71	71	71
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	20	20	20	18	18	18
Electric Generators[4]	957	1136	1097	1093	1262	1214	1169	1369	1334	1269
Total	**1050**	**1232**	**1193**	**1189**	**1357**	**1309**	**1264**	**1463**	**1429**	**1364**
Discrepancy and Stock Change[5]	**59**	**-5**	**-8**	**-1**	**-6**	**-4**	**-6**	**-7**	**2**	**-6**
Average Minemouth Price										
(2001 dollars per short ton)	17.59	15.06	14.92	15.25	14.23	13.46	15.44	14.22	13.02	15.41
(2001 dollars per million Btu)	0.83	0.73	0.72	0.74	0.70	0.67	0.74	0.70	0.65	0.74
Delivered Prices (2001 dollars per short ton)[6]										
Industrial	32.83	30.05	29.80	29.92	28.37	27.52	28.28	27.91	27.00	27.82
Coke Plants	46.42	41.25	41.24	41.23	38.11	38.11	38.26	36.77	36.66	36.61
Electric Generators										
(2001 dollars per short ton)	25.05	23.71	24.09	24.23	22.37	22.56	23.66	22.17	22.26	23.78
(2001 dollars per million Btu)	1.25	1.17	1.19	1.19	1.12	1.14	1.15	1.11	1.14	1.15
Average	**26.05**	**24.40**	**24.76**	**24.89**	**22.91**	**23.07**	**24.15**	**22.63**	**22.68**	**24.17**
Exports[7]	36.97	32.68	32.70	32.70	30.90	30.77	30.68	30.40	30.19	29.51

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.
[2]Production plus net imports and 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 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D9. Coal Production by Region and Type
(Million Short Tons)

Supply Regions and Coal Types	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Northern Appalachia	**153.6**	**135.2**	**121.3**	**135.9**	**131.0**	**106.2**	**120.4**	**143.2**	**94.1**	**120.4**
Medium Sulfur (Premium)[1]	3.8	2.5	2.5	2.5	2.3	2.3	2.3	2.4	2.4	2.4
Low Sulfur (Bituminous)[2]	0.4	0.0	0.2	0.2	0.0	0.1	0.0	0.0	0.0	0.0
Medium Sulfur (Bituminous)[2]	75.2	67.1	64.1	66.3	62.6	63.3	64.9	70.6	63.5	67.7
High Sulfur (Bituminous)	63.6	54.2	44.9	57.3	54.6	30.8	46.5	58.8	18.5	44.8
High Sulfur (Gob)[3]	10.6	11.4	9.7	9.7	11.4	9.7	6.6	11.4	9.7	5.5
Central Appalachia	**267.0**	**264.5**	**268.6**	**267.7**	**259.6**	**251.6**	**293.8**	**261.3**	**257.9**	**300.2**
Medium Sulfur (Premium)[1]	38.9	31.9	31.5	31.4	27.1	27.1	27.1	24.2	24.0	23.8
Low Sulfur (Bituminous)	71.2	73.6	77.1	76.1	70.6	73.6	94.7	72.1	79.0	98.0
Medium Sulfur (Bituminous)	156.8	159.0	159.9	160.2	161.9	151.0	172.0	165.0	155.0	178.4
Southern Appalachia	**22.8**	**20.1**	**18.2**	**18.2**	**16.8**	**14.9**	**17.7**	**15.3**	**13.7**	**17.0**
Low Sulfur (Premium)[1]	6.7	6.0	6.0	6.0	4.9	4.9	4.9	4.2	4.1	4.1
Low Sulfur (Bituminous)	5.9	4.0	3.6	3.4	3.8	3.9	5.1	3.5	3.5	5.5
Medium Sulfur (Bituminous)	10.2	10.0	8.7	8.9	8.1	6.2	7.8	7.6	6.0	7.4
Eastern Interior	**96.0**	**107.4**	**82.2**	**89.2**	**110.0**	**71.2**	**107.0**	**122.4**	**47.6**	**119.6**
Medium Sulfur (Bituminous)	33.6	33.7	33.1	32.4	38.4	36.6	49.7	41.3	29.7	59.2
High Sulfur (Bituminous)	61.8	69.7	46.2	53.8	67.8	31.7	54.5	77.4	15.0	57.5
Medium Sulfur (Lignite)	0.6	4.1	2.9	2.9	3.8	2.9	2.9	3.7	2.9	2.9
Western Interior High Sulfur (Bituminous)	**2.4**	**2.5**	**1.1**	**1.2**	**2.0**	**0.5**	**0.6**	**1.8**	**0.4**	**0.4**
Gulf	**48.6**	**45.1**	**40.8**	**40.8**	**35.2**	**26.8**	**20.6**	**33.7**	**22.1**	**14.4**
Medium Sulfur (Lignite)	33.4	28.0	31.0	30.1	21.4	23.1	17.3	20.3	18.7	11.0
High Sulfur (Lignite)	15.2	17.1	9.8	10.7	13.9	3.7	3.4	13.4	3.4	3.4
Dakota Medium Sulfur (Lignite)	**30.8**	**31.6**	**31.0**	**31.0**	**33.5**	**20.0**	**19.8**	**33.6**	**20.0**	**20.0**
Powder/Green River	**407.5**	**511.4**	**502.3**	**485.9**	**641.9**	**692.8**	**534.8**	**705.5**	**838.5**	**595.1**
Low Sulfur (Bituminous)	0.0	1.6	1.6	1.6	1.3	1.5	0.9	0.8	1.2	0.5
Low Sulfur (Sub-Bituminous)	375.1	483.2	467.4	451.2	603.7	654.4	506.4	659.9	807.9	566.9
Medium Sulfur (Sub-Bituminous)	32.5	26.6	33.3	33.2	36.9	36.9	27.5	44.8	29.5	27.6
Rocky Mountain	**60.3**	**81.7**	**93.0**	**91.5**	**87.6**	**87.5**	**106.2**	**98.9**	**94.8**	**127.0**
Low Sulfur (Bituminous)	50.5	72.5	83.8	82.3	81.1	81.0	99.4	92.4	88.3	119.9
Low Sulfur (Sub-Bituminous)	9.8	9.2	9.2	9.2	6.5	6.5	6.8	6.5	6.5	7.1
Arizona/New Mexico	**43.0**	**34.8**	**33.6**	**34.0**	**30.8**	**30.8**	**34.8**	**30.8**	**30.8**	**35.5**
Low Sulfur (Bituminous)	20.9	16.3	15.1	15.5	14.2	14.2	18.2	14.2	14.2	18.8
Medium Sulfur (Bituminous)	0.7	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Medium Sulfur (Sub-bituminous)	21.5	11.5	11.5	11.5	9.5	9.5	9.5	9.5	9.5	9.5
Washington/Alaska Medium Sulfur (Sub-Bituminous)	**6.1**	**6.2**	**6.2**	**6.2**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**	**6.3**

Table D9. Coal Production by Region and Type (Continued)

(Million Short Tons)

Supply Regions and Coal Types	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Subtotals: All Regions										
Premium Metallurgical[1]	49.5	40.4	40.0	39.8	34.3	34.3	34.3	30.8	30.5	30.3
Bituminous	553.2	571.2	546.5	566.3	573.5	501.3	621.3	612.7	481.4	665.2
Sub-Bituminous	445.0	536.7	527.5	511.2	662.9	713.6	556.5	727.0	859.7	617.4
Lignite	90.6	92.1	84.3	84.4	83.9	59.3	50.0	82.4	54.7	42.8
Low Sulfur	540.5	666.4	664.0	645.4	786.1	840.0	736.4	853.6	1004.8	820.9
Medium Sulfur	444.2	419.1	422.6	423.6	418.8	392.3	414.2	436.4	374.6	423.4
High Sulfur	153.6	154.9	111.7	132.6	149.7	76.3	111.5	162.9	46.9	111.6
Underground	380.2	405.4	392.1	403.6	420.0	368.8	449.6	452.8	355.7	488.4
Surface	758.1	835.0	806.2	798.0	934.7	939.8	812.5	1000.1	1070.6	867.4
U.S. Total	**1138.3**	**1240.4**	**1198.3**	**1201.6**	**1354.6**	**1308.6**	**1262.1**	**1452.9**	**1426.3**	**1355.8**

[1]"Premium" coal is used to make metallurgical coke.
[2]Includes Pennsylvania anthracite.
[3]Waste coal delivered to Independent Power Producers (IPP) that is not included in other Energy Information Administration coal production tables. The totals for this table include this waste coal tonnage.
Northern Appalachia: Pennsylvania, Maryland, Ohio, Northern West Virginia (Pennsylvania anthracite is included under low and medium sulfur bituminous).
Central Appalachia: Southern West Virginia, Virginia, Eastern Kentucky.
Southern Appalachia: Alabama, Tennessee.
Eastern Interior: Illinois, Indiana, Mississippi, Western Kentucky.
Western Interior (Bituminous only): Iowa, Missouri, Kansas, Oklahoma, Arkansas, Texas.
Gulf (Lignite only): Texas, Louisiana, Arkansas.
Dakota: North Dakota, Eastern Montana (Lignite only).
Powder/Green River: Wyoming, Montana (Sub-Bituminous and Bituminous)
Rocky Mountain: Colorado, Utah.
Sulfur Definitions:
Low Sulfur: 0 - 0.60 pounds of sulfur per million British thermal unit.
Medium Sulfur: 0.61 - 1.67 pounds of sulfur per million British thermal unit.
High Sulfur: Over 1.67 pounds of sulfur per million British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D10. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.10	78.66	78.66	78.66	78.65	78.65	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	3.81	3.89	3.89	5.46	5.54	5.55	5.94	5.91	6.00
Municipal Solid Waste[3]	3.25	3.99	3.99	3.99	4.32	4.38	4.38	4.39	4.39	4.39
Wood and Other Biomass[4]	1.80	2.09	2.09	2.09	2.24	2.20	2.20	2.36	2.20	2.20
Solar Thermal	0.33	0.44	0.44	0.44	0.48	0.48	0.48	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.27	0.27	0.27	0.36	0.36	0.36
Wind	4.29	8.13	9.63	9.64	10.15	11.37	11.37	10.98	11.74	11.90
Total	**90.62**	**97.22**	**98.80**	**98.81**	**101.57**	**102.88**	**102.89**	**103.19**	**103.75**	**103.99**
Generation (billion kilowatthours)										
Conventional Hydropower	213.82	300.90	300.89	300.89	300.07	300.06	300.05	300.36	300.35	300.35
Geothermal[2]	13.81	21.99	22.65	22.67	35.54	36.17	36.26	39.58	39.35	39.97
Municipal Solid Waste[3]	19.55	28.52	28.50	28.50	30.99	31.44	31.44	31.61	31.57	31.59
Wood and Other Biomass[4]	9.38	20.88	26.03	26.31	21.51	27.12	28.07	22.02	27.45	27.28
Dedicated Plants	7.67	12.44	12.23	12.57	13.41	12.83	13.19	14.09	12.91	13.28
Cofiring	1.71	8.44	13.79	13.74	8.10	14.29	14.88	7.94	14.54	14.00
Solar Thermal	0.49	0.77	0.77	0.77	0.90	0.90	0.90	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.66	0.66	0.66	0.88	0.88	0.88
Wind	5.78	22.55	27.83	27.84	29.65	33.92	33.90	32.68	35.30	35.85
Total	**262.85**	**395.86**	**406.91**	**407.23**	**419.31**	**430.26**	**431.28**	**428.11**	**435.88**	**436.90**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[6]										
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.92	5.92	5.91	7.79	7.80	7.79	8.74	8.74	8.75
Total	**4.69**	**6.21**	**6.20**	**6.20**	**8.07**	**8.08**	**8.07**	**9.03**	**9.03**	**9.03**
Other End-Use Generators[7]										
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.62	0.63	0.63	0.96	0.97	0.97
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.71**	**1.72**	**1.72**	**2.05**	**2.06**	**2.06**
Generation (billion kilowatthours)										
Combined Heat and Power[6]										
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.51	37.47	37.46	48.42	48.46	48.42	53.98	53.97	54.00
Total	**31.13**	**39.66**	**39.62**	**39.61**	**50.57**	**50.61**	**50.57**	**56.13**	**56.12**	**56.15**
Other End-Use Generators[7]										
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	1.32	1.34	1.35	2.02	2.04	2.04
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.56**	**5.58**	**5.58**	**6.25**	**6.28**	**6.28**

[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]Includes projections for energy crops after 2010.
[5]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Includes 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 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. 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: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D11. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Residential										
Petroleum	27.2	27.6	27.6	27.6	25.6	25.7	25.7	25.0	25.0	25.0
Natural Gas	71.1	81.1	81.0	81.1	88.0	88.0	88.0	91.9	91.6	91.6
Coal	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Electricity	215.1	245.7	238.9	239.0	271.6	262.6	261.9	289.5	279.5	278.5
Total	**313.8**	**354.8**	**347.9**	**348.1**	**385.6**	**376.6**	**375.9**	**406.7**	**396.4**	**395.4**
Commercial										
Petroleum	14.0	13.7	13.7	13.7	14.1	14.1	14.1	14.1	14.2	14.2
Natural Gas	48.0	53.8	53.8	53.8	61.0	61.0	61.0	65.0	64.8	64.8
Coal	2.3	2.4	2.5	2.4	2.7	2.7	2.7	2.8	2.8	2.8
Electricity	214.5	249.8	243.2	243.4	299.0	289.7	288.5	329.5	318.8	317.5
Total	**278.8**	**319.8**	**313.1**	**313.4**	**376.8**	**367.6**	**366.4**	**411.3**	**400.5**	**399.2**
Industrial[1]										
Petroleum	97.9	98.0	97.8	97.7	105.0	105.4	105.2	109.4	109.4	109.2
Natural Gas[2]	123.4	147.9	148.2	148.4	171.9	172.4	173.3	184.0	184.7	185.9
Coal	52.1	56.5	56.4	56.4	56.2	56.2	56.1	56.2	56.2	56.2
Electricity	178.1	197.7	193.1	192.9	225.6	218.7	217.7	243.0	235.1	233.9
Total	**451.5**	**500.0**	**495.5**	**495.4**	**558.7**	**552.7**	**552.3**	**592.6**	**585.4**	**585.3**
Transportation										
Petroleum[3]	501.4	611.4	610.7	610.6	737.6	737.5	737.2	802.6	802.3	802.4
Natural Gas[4]	9.2	12.1	12.3	12.3	15.5	15.6	15.6	16.4	16.5	16.5
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	3.9	4.6	4.5	4.5	6.0	5.8	5.8	6.9	6.7	6.7
Total	**514.5**	**628.2**	**627.6**	**627.5**	**759.1**	**759.0**	**758.6**	**826.0**	**825.6**	**825.6**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	640.5	750.7	749.8	749.6	882.4	882.7	882.2	951.1	950.9	950.8
Natural Gas	251.7	294.9	295.3	295.6	336.4	337.0	337.9	357.3	357.6	358.8
Coal	54.7	59.3	59.3	59.2	59.2	59.3	59.1	59.3	59.4	59.3
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	611.6	697.8	679.8	679.8	802.2	776.8	773.9	868.9	840.1	836.6
Total	**1558.6**	**1802.7**	**1784.1**	**1784.3**	**2080.2**	**2055.9**	**2053.2**	**2236.6**	**2208.0**	**2205.5**
Electric Generators[6]										
Petroleum	27.5	10.8	7.9	8.0	12.8	7.9	8.5	13.4	10.0	10.0
Natural Gas	77.7	100.0	104.2	103.5	143.8	152.6	150.0	154.7	160.3	157.9
Coal	506.4	587.0	567.6	568.3	645.6	616.4	615.4	700.8	669.7	668.7
Total	**611.6**	**697.8**	**679.8**	**679.8**	**802.2**	**776.8**	**773.9**	**868.9**	**840.1**	**836.6**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	668.0	761.5	757.8	757.6	895.2	890.6	890.7	964.5	960.9	960.8
Natural Gas	329.4	395.0	399.5	399.1	480.2	489.6	487.9	512.0	518.0	516.7
Coal	561.1	646.3	626.8	627.6	704.8	675.7	674.6	760.1	729.1	728.0
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1802.7**	**1784.1**	**1784.3**	**2080.2**	**2055.9**	**2053.2**	**2236.6**	**2208.0**	**2205.5**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.6**	**6.0**	**5.9**	**5.9**	**6.4**	**6.3**	**6.3**	**6.6**	**6.5**	**6.5**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Table D12. Emissions, Allowance Prices, and Emission Controls in the Electric Power Sector

Supply and Disposition	2001	Projections								
		2010			2020			2025		
		Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P	Reference	Carper 2P	Carper 3P
Emissions										
Nitrogen Oxides (million tons)	4.75	3.93	1.81	1.84	4.05	1.70	1.72	4.11	1.72	1.72
Sulfur Dioxide (million tons)	10.64	9.66	5.20	5.01	8.95	3.82	3.85	8.95	3.30	3.51
From Coal	10.05	9.47	5.09	4.89	8.72	3.73	3.74	8.75	3.21	3.42
From Oil/Other	0.60	0.19	0.11	0.12	0.23	0.10	0.10	0.20	0.09	0.10
Mercury (tons)	49.49	52.56	41.76	18.15	53.43	42.24	9.99	54.33	44.07	10.00
Carbon Dioxide (million metric tons carbon equivalent)	611.57	697.82	679.76	679.84	802.16	776.83	773.94	868.91	840.07	836.60
Allowance Prices										
Nitrogen Oxides (2001 dollars per ton)										
Regional/Seasonal	0.00	4741.70	0.00	0.00	5550.48	0.00	0.00	6207.45	0.00	0.00
East/Annual	0.00	0.00	2293.95	1884.87	0.00	2256.51	1935.17	0.00	2358.48	2059.98
West/Annual	0.00	0.00	2293.98	1884.90	0.00	2256.53	1935.19	0.00	2358.50	2060.00
Sulfur Dioxide (2001 dollars per ton)	76.93	100.52	1159.58	877.28	89.80	1424.44	1248.61	51.70	1680.04	1453.87
Mercury (thousand 2001 dollars per pound)	0.00	0.00	0.00	0.00	0.00	0.00	29.69	0.00	0.00	31.91
Carbon Dioxide (2001 dollars per million metric ton carbon equivalent)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofits (gigawatts)										
Scrubber[6]										
Planned	1.49	20.65	20.65	20.65	22.82	22.82	22.82	22.82	22.82	22.82
Unplanned	0.00	0.00	50.98	65.30	0.00	80.50	86.01	0.00	91.94	94.22
Total	1.49	20.65	71.63	85.95	22.82	103.32	108.83	22.82	114.76	117.04
Nitrogen Oxides Controls										
Combustion	0.00	16.01	28.46	27.69	17.45	30.94	29.91	17.83	31.27	29.93
SCR Post-combustion	0.00	79.20	149.98	153.44	83.24	162.45	170.84	84.52	162.94	172.27
SNCR Post-combustion	0.00	16.67	16.98	9.15	35.40	40.34	16.37	47.18	43.90	21.20
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs per million Btu)	540.47	666.41	663.98	645.37	786.14	840.01	736.39	853.64	1004.78	820.86
Medium Sulfur	444.21	419.09	422.62	423.60	418.81	392.25	414.22	436.35	374.56	423.36
High Sulfur (> 1.67 lbs per million Btu)	153.63	154.89	111.72	132.64	149.68	76.31	111.47	162.92	46.94	111.56
Interregional Sulfur Dioxide Allowances										
Target (million tons)	9.48	8.95	4.50	4.50	8.95	2.25	2.25	8.95	2.25	2.25
Cumulative Banked Allowances	9.23	1.03	20.04	20.39	0.00	7.79	8.98	0.00	1.41	1.91
Coal Characteristics										
SO_2 Content (lbs per million Btu)	1.85	1.73	1.58	1.68	1.62	1.34	1.56	1.62	1.16	1.52
Mercury Content (lbs per trillion Btu)	7.50	7.25	7.06	7.20	7.04	6.77	6.77	6.99	6.61	6.61
ACI Controls (gigawatts)										
Spray Cooling	0.00	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	0.00	124.43	0.00	0.00	134.96	0.00	0.00	137.70
ACI Mercury Removal (tons)	**0.00**	**0.00**	**0.00**	**21.07**	**0.00**	**0.00**	**25.59**	**0.00**	**0.00**	**25.55**
Allowance Revenues (billion 2001 dollars)										
Nitrogen Oxides	0.00	2.24	4.29	3.53	2.63	3.84	3.29	2.94	4.01	3.50
Sulfur Dioxide	2.02	1.74	8.11	6.82	1.30	8.57	7.81	1.10	7.63	7.66
Mercury	0.00	0.00	0.00	0.00	0.00	0.00	1.28	0.00	0.00	1.53
Carbon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**2.02**	**3.98**	**12.41**	**10.34**	**3.92**	**12.41**	**12.38**	**4.03**	**11.64**	**12.70**

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 2001 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA2P.D080503A, IMCA3P.D080503A.

Appendix E Tables:

Reference, Carper 4P with High Offsets, Carper 4P mid Offsets, Carper 4P no Offsets

Table E1. Total Energy Supply and Disposition Summary

(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Production									
Crude Oil and Lease Condensate	12.29	11.93	11.94	11.95	11.95	11.29	11.29	11.28	11.33
Natural Gas Plant Liquids	2.65	3.14	3.17	3.19	3.24	3.71	3.77	3.74	3.77
Dry Natural Gas	19.97	22.26	22.51	22.62	22.98	27.15	27.59	27.36	27.61
Coal	23.97	25.56	24.71	24.33	22.90	29.48	25.62	23.74	19.35
Nuclear Power	8.03	8.22	8.22	8.22	8.29	8.25	8.25	8.25	8.33
Renewable Energy[1]	5.32	7.28	7.44	7.48	8.13	8.81	9.24	10.65	15.10
Other[2]	0.57	0.85	0.85	0.85	0.85	0.80	0.79	0.79	0.79
Total	**72.80**	**79.24**	**78.84**	**78.63**	**78.34**	**89.49**	**86.55**	**85.81**	**86.27**
Imports									
Crude Oil[3]	20.26	25.07	25.03	25.01	24.99	28.55	28.44	28.44	28.26
Petroleum Products[4]	5.04	6.34	6.06	6.05	5.99	14.86	14.67	14.70	14.45
Natural Gas	4.18	5.54	5.63	5.77	5.92	8.61	10.26	10.71	10.39
Other Imports[5]	0.73	0.94	0.99	0.79	0.80	0.95	0.96	0.53	0.53
Total	**30.21**	**37.89**	**37.71**	**37.62**	**37.70**	**52.96**	**54.32**	**54.38**	**53.62**
Exports									
Petroleum[6]	2.01	2.25	2.26	2.25	2.25	2.42	2.44	2.43	2.39
Natural Gas	0.37	0.56	0.56	0.56	0.56	0.36	0.37	0.36	0.36
Coal	1.27	0.87	0.86	0.88	0.86	0.61	0.65	0.61	0.61
Total	**3.64**	**3.67**	**3.68**	**3.70**	**3.67**	**3.39**	**3.45**	**3.40**	**3.35**
Discrepancy[7]	**2.08**	**0.22**	**0.20**	**0.15**	**0.24**	**0.20**	**0.20**	**-0.14**	**0.41**
Consumption									
Petroleum Products[8]	38.46	44.48	44.19	44.18	44.16	56.18	55.91	55.91	55.62
Natural Gas	23.26	27.61	27.93	28.19	28.71	35.79	37.87	38.10	38.06
Coal	22.02	25.32	24.50	23.93	22.41	29.75	25.85	23.92	18.92
Nuclear Power	8.03	8.22	8.22	8.22	8.29	8.25	8.25	8.25	8.33
Renewable Energy[1]	5.32	7.28	7.44	7.48	8.13	8.81	9.24	10.65	15.10
Other[9]	0.21	0.33	0.38	0.41	0.42	0.08	0.09	0.10	0.09
Total	**97.29**	**113.24**	**112.67**	**112.41**	**112.13**	**138.87**	**137.22**	**136.93**	**136.13**
Net Imports - Petroleum	**23.29**	**29.16**	**28.84**	**28.81**	**28.73**	**40.99**	**40.66**	**40.70**	**40.32**
Prices (2001 dollars per unit)									
World Oil Price (dollars per barrel)[10]	22.01	23.99	23.99	23.99	23.99	26.57	26.57	26.57	26.57
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	4.12	3.42	3.42	3.47	3.57	3.97	4.16	4.33	4.24
Coal Minemouth Price (dollars per ton)	17.59	15.06	15.46	15.70	15.50	14.22	14.92	15.32	13.99
Average Electricity Price (cents per kilowatthour)	7.3	6.4	6.7	6.8	6.8	6.8	7.1	7.3	7.5

[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 E18 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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 petroleum supply values: EIA, *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). Other 2001 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002) and EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E2. Energy Consumption by Sector and Source

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Energy Consumption									
Residential									
Distillate Fuel	0.91	0.91	0.91	0.91	0.91	0.81	0.81	0.81	0.81
Kerosene	0.10	0.08	0.08	0.08	0.08	0.06	0.06	0.06	0.06
Liquefied Petroleum Gas	0.50	0.47	0.47	0.47	0.47	0.46	0.47	0.47	0.47
Petroleum Subtotal	1.50	1.46	1.46	1.46	1.46	1.33	1.33	1.33	1.33
Natural Gas	4.94	5.63	5.63	5.62	5.61	6.38	6.32	6.30	6.32
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.39	0.41	0.41	0.41	0.41	0.40	0.40	0.40	0.40
Electricity	4.10	4.93	4.88	4.87	4.87	5.94	5.87	5.85	5.79
Delivered Energy	**10.94**	**12.44**	**12.40**	**12.38**	**12.37**	**14.07**	**13.94**	**13.89**	**13.86**
Electricity Related Losses	9.15	10.41	10.23	10.15	10.07	11.51	11.02	10.94	10.74
Total	**20.08**	**22.85**	**22.62**	**22.53**	**22.44**	**25.58**	**24.96**	**24.83**	**24.60**
Commercial									
Distillate Fuel	0.46	0.51	0.51	0.52	0.52	0.52	0.53	0.53	0.53
Residual Fuel	0.09	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04
Petroleum Subtotal	0.71	0.70	0.71	0.71	0.71	0.72	0.73	0.73	0.74
Natural Gas	3.33	3.74	3.74	3.73	3.72	4.51	4.48	4.45	4.50
Coal	0.09	0.10	0.10	0.09	0.10	0.11	0.11	0.11	0.11
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.08	5.01	4.97	4.97	4.97	6.76	6.68	6.68	6.63
Delivered Energy	**8.32**	**9.65**	**9.61**	**9.60**	**9.59**	**12.21**	**12.11**	**12.08**	**12.08**
Electricity Related Losses	9.12	10.58	10.41	10.34	10.26	13.10	12.55	12.51	12.30
Total	**17.44**	**20.23**	**20.03**	**19.94**	**19.85**	**25.31**	**24.66**	**24.59**	**24.38**
Industrial[4]									
Distillate Fuel	1.13	1.21	1.21	1.21	1.21	1.44	1.44	1.44	1.41
Liquefied Petroleum Gas	2.10	2.55	2.55	2.55	2.55	3.29	3.30	3.32	3.30
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.43	1.82	1.82	1.82	1.81
Residual Fuel	0.23	0.19	0.19	0.19	0.19	0.20	0.20	0.21	0.20
Motor Gasoline[2]	0.15	0.17	0.17	0.17	0.17	0.19	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.27	4.26	4.26	4.26	4.57	4.59	4.59	4.56
Petroleum Subtotal	8.79	9.82	9.80	9.80	9.80	11.52	11.54	11.58	11.49
Natural Gas	7.74	9.07	9.10	9.09	9.11	11.28	11.36	11.33	11.53
Lease and Plant Fuel[6]	1.20	1.38	1.39	1.39	1.41	1.73	1.75	1.74	1.75
Natural Gas Subtotal	8.94	10.45	10.49	10.49	10.52	13.01	13.11	13.07	13.29
Metallurgical Coal	0.72	0.66	0.66	0.66	0.66	0.50	0.50	0.50	0.50
Steam Coal	1.42	1.45	1.45	1.45	1.45	1.54	1.54	1.54	1.53
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.11	0.18	0.18	0.17	0.17
Coal Subtotal	2.16	2.23	2.22	2.22	2.22	2.22	2.21	2.22	2.20
Renewable Energy[7]	1.82	2.22	2.22	2.22	2.21	3.05	3.05	3.05	3.04
Electricity	3.39	3.96	3.95	3.94	3.93	4.99	4.94	4.93	4.82
Delivered Energy	**25.10**	**28.68**	**28.68**	**28.67**	**28.68**	**34.79**	**34.85**	**34.84**	**34.84**
Electricity Related Losses	7.57	8.37	8.26	8.20	8.11	9.66	9.27	9.22	8.94
Total	**32.67**	**37.05**	**36.94**	**36.87**	**36.79**	**44.45**	**44.12**	**44.06**	**43.78**

Table E2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Transportation									
Distillate Fuel[8]	5.44	7.09	7.07	7.06	7.04	9.55	9.51	9.48	9.42
Jet Fuel[9]	3.43	3.93	3.93	3.93	3.93	5.67	5.67	5.67	5.67
Motor Gasoline[2]	16.26	19.81	19.79	19.79	19.78	25.48	25.46	25.46	25.45
Residual Fuel	0.84	0.83	0.83	0.83	0.83	0.87	0.87	0.87	0.86
Liquefied Petroleum Gas	0.02	0.05	0.05	0.05	0.05	0.09	0.08	0.08	0.08
Other Petroleum[10]	0.24	0.26	0.26	0.26	0.26	0.32	0.32	0.32	0.32
Petroleum Subtotal	26.22	31.97	31.93	31.92	31.89	41.97	41.91	41.89	41.81
Pipeline Fuel Natural Gas	0.63	0.78	0.80	0.80	0.81	1.03	1.05	1.04	1.04
Compressed Natural Gas	0.01	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	0.01	0.01	0.01	0.01
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.07	0.09	0.09	0.09	0.09	0.14	0.14	0.14	0.14
Delivered Energy	**26.94**	**32.91**	**32.88**	**32.87**	**32.86**	**43.26**	**43.21**	**43.18**	**43.11**
Electricity Related Losses	0.17	0.20	0.19	0.19	0.19	0.27	0.27	0.26	0.26
Total	**27.10**	**33.11**	**33.08**	**33.06**	**33.05**	**43.53**	**43.48**	**43.45**	**43.37**
Delivered Energy Consumption for All Sectors									
Distillate Fuel	7.94	9.73	9.71	9.70	9.68	12.32	12.28	12.27	12.18
Kerosene	0.15	0.12	0.12	0.12	0.12	0.10	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	3.93	5.67	5.67	5.67	5.67
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.16	3.94	3.94	3.97	3.95
Motor Gasoline[2]	16.46	20.01	19.99	19.99	19.98	25.71	25.69	25.69	25.67
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.43	1.82	1.82	1.82	1.81
Residual Fuel	1.15	1.06	1.06	1.06	1.06	1.12	1.12	1.12	1.11
Other Petroleum[12]	4.24	4.51	4.50	4.50	4.49	4.87	4.89	4.89	4.86
Petroleum Subtotal	37.21	43.96	43.90	43.89	43.86	55.54	55.52	55.53	55.36
Natural Gas	16.02	18.50	18.52	18.50	18.50	22.28	22.28	22.18	22.46
Lease and Plant Fuel Plant[6]	1.20	1.38	1.39	1.39	1.41	1.73	1.75	1.74	1.75
Pipeline Natural Gas	0.63	0.78	0.80	0.80	0.81	1.03	1.05	1.04	1.04
Natural Gas Subtotal	17.86	20.66	20.71	20.69	20.72	25.04	25.07	24.96	25.26
Metallurgical Coal	0.72	0.66	0.66	0.66	0.66	0.50	0.50	0.50	0.50
Steam Coal	1.53	1.56	1.56	1.56	1.56	1.66	1.66	1.67	1.65
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.11	0.18	0.18	0.17	0.17
Coal Subtotal	2.27	2.34	2.33	2.33	2.33	2.34	2.34	2.34	2.32
Renewable Energy[13]	2.31	2.74	2.73	2.73	2.73	3.57	3.56	3.56	3.56
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.65	13.99	13.90	13.87	13.86	17.84	17.63	17.60	17.38
Delivered Energy	**71.29**	**83.68**	**83.57**	**83.52**	**83.50**	**104.33**	**104.12**	**103.99**	**103.88**
Electricity Related Losses	26.00	29.56	29.10	28.89	28.63	34.54	33.10	32.93	32.24
Total	**97.29**	**113.24**	**112.67**	**112.41**	**112.13**	**138.87**	**137.22**	**136.93**	**136.13**
Electric Power[14]									
Distillate Fuel	0.17	0.10	0.09	0.09	0.09	0.18	0.20	0.19	0.08
Residual Fuel	1.08	0.41	0.20	0.21	0.22	0.47	0.19	0.19	0.18
Petroleum Subtotal	1.25	0.51	0.29	0.29	0.30	0.64	0.39	0.38	0.26
Natural Gas	5.40	6.95	7.22	7.50	7.99	10.75	12.80	13.14	12.79
Steam Coal	19.75	22.99	22.17	21.60	20.08	27.41	23.51	21.58	16.60
Nuclear Power	8.03	8.22	8.22	8.22	8.29	8.25	8.25	8.25	8.33
Renewable Energy[15]	3.01	4.55	4.71	4.75	5.40	5.25	5.68	7.09	11.55
Electricity Imports	0.21	0.33	0.38	0.41	0.42	0.08	0.09	0.10	0.09
Total	**37.65**	**43.55**	**42.99**	**42.76**	**42.49**	**52.38**	**50.73**	**50.53**	**49.62**

Table E2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Total Energy Consumption									
Distillate Fuel	8.10	9.84	9.80	9.79	9.77	12.49	12.48	12.46	12.26
Kerosene	0.15	0.12	0.12	0.12	0.12	0.10	0.10	0.10	0.10
Jet Fuel[9]	3.43	3.93	3.93	3.93	3.93	5.67	5.67	5.67	5.67
Liquefied Petroleum Gas	2.70	3.16	3.16	3.16	3.16	3.94	3.94	3.97	3.95
Motor Gasoline[2]	16.46	20.01	19.99	19.99	19.98	25.71	25.69	25.69	25.67
Petrochemical Feedstock	1.14	1.43	1.43	1.43	1.43	1.82	1.82	1.82	1.81
Residual Fuel	2.23	1.47	1.26	1.27	1.28	1.58	1.31	1.31	1.29
Other Petroleum[12]	4.24	4.51	4.50	4.50	4.49	4.87	4.89	4.89	4.86
Petroleum Subtotal	38.46	44.48	44.19	44.18	44.16	56.18	55.91	55.91	55.62
Natural Gas	21.42	25.45	25.75	26.00	26.49	33.03	35.08	35.32	35.26
Lease and Plant Fuel[6]	1.20	1.38	1.39	1.39	1.41	1.73	1.75	1.74	1.75
Pipeline Natural Gas	0.63	0.78	0.80	0.80	0.81	1.03	1.05	1.04	1.04
Natural Gas Subtotal	23.26	27.61	27.93	28.19	28.71	35.79	37.87	38.10	38.06
Metallurgical Coal	0.72	0.66	0.66	0.66	0.66	0.50	0.50	0.50	0.50
Steam Coal	21.28	24.55	23.73	23.16	21.64	29.07	25.17	23.24	18.25
Net Coal Coke Imports	0.03	0.11	0.11	0.11	0.11	0.18	0.18	0.17	0.17
Coal Subtotal	22.02	25.32	24.50	23.93	22.41	29.75	25.85	23.92	18.92
Nuclear Power	8.03	8.22	8.22	8.22	8.29	8.25	8.25	8.25	8.33
Renewable Energy[16]	5.32	7.28	7.44	7.48	8.13	8.81	9.24	10.65	15.10
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.21	0.33	0.38	0.41	0.42	0.08	0.09	0.10	0.09
Total	**97.29**	**113.24**	**112.67**	**112.41**	**112.13**	**138.87**	**137.22**	**136.93**	**136.13**
Energy Use and Related Statistics									
Delivered Energy Use	71.29	83.68	83.57	83.52	83.50	104.33	104.12	103.99	103.88
Total Energy Use	97.29	113.24	112.67	112.41	112.13	138.87	137.22	136.93	136.13
Population (millions)	278.18	300.24	300.24	300.24	300.24	338.24	338.24	338.24	338.24
Gross Domestic Product (billion 1996 dollars)	9215	12254	12241	12237	12231	18914	18902	18899	18882
Carbon Dioxide Emissions (million metric tons carbon equivalent)	1558.6	1802.7	1780.3	1768.9	1737.2	2236.6	2159.2	2112.5	1980.5

[1]Includes wood used for residential heating. See Table E18 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 E18 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.

[4]Fuel consumption includes consumption for combined heat and power, which produces electricity, both for sale to the grid and for own use, and other useful thermal energy.

[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 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).

[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 2001 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: 2001 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 population and gross domestic product: Global Insight macroeconomic model CTL0802. 2001 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E3. Energy Prices by Sector and Source

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Residential	**15.80**	**14.02**	**14.30**	**14.44**	**14.48**	**14.99**	**15.48**	**15.78**	**15.95**
Primary Energy[1]	9.73	8.08	8.09	8.12	8.19	8.59	8.76	8.89	8.78
Petroleum Products[2]	10.85	10.02	10.02	10.01	10.01	11.23	11.24	11.24	11.24
Distillate Fuel	8.99	7.99	7.99	7.98	7.98	8.92	8.92	8.92	8.92
Liquefied Petroleum Gas	14.84	14.35	14.34	14.33	14.32	15.58	15.60	15.60	15.61
Natural Gas	9.41	7.60	7.60	7.65	7.73	8.05	8.26	8.40	8.28
Electricity	25.36	22.58	23.33	23.64	23.63	23.31	24.24	24.79	25.45
Commercial	**15.50**	**13.49**	**13.89**	**14.06**	**14.08**	**15.20**	**15.72**	**16.03**	**16.21**
Primary Energy[1]	7.81	6.45	6.46	6.49	6.56	7.07	7.23	7.35	7.25
Petroleum Products[2]	7.27	6.77	6.77	6.76	6.76	7.81	7.78	7.77	7.77
Distillate Fuel	6.40	5.66	5.67	5.66	5.66	6.75	6.74	6.74	6.73
Residual Fuel	3.46	4.01	3.97	3.97	3.97	4.40	4.34	4.34	4.34
Natural Gas	8.09	6.52	6.52	6.57	6.65	7.09	7.28	7.43	7.31
Electricity	23.27	19.88	20.66	20.95	20.93	21.62	22.48	22.90	23.42
Industrial[3]	**7.11**	**6.42**	**6.50**	**6.56**	**6.60**	**7.31**	**7.48**	**7.61**	**7.61**
Primary Energy	5.83	5.19	5.19	5.21	5.25	6.00	6.09	6.17	6.10
Petroleum Products[2]	7.72	7.07	7.07	7.06	7.06	8.15	8.16	8.17	8.18
Distillate Fuel	6.55	5.74	5.75	5.74	5.74	7.18	7.18	7.18	7.17
Liquefied Petroleum Gas	12.34	9.92	9.92	9.91	9.91	11.14	11.16	11.17	11.18
Residual Fuel	3.28	3.72	3.69	3.70	3.70	4.11	4.08	4.08	4.08
Natural Gas[4]	4.87	4.04	4.04	4.09	4.19	4.66	4.84	5.01	4.89
Metallurgical Coal	1.69	1.50	1.51	1.51	1.51	1.34	1.34	1.34	1.34
Steam Coal	1.46	1.38	1.38	1.38	1.37	1.29	1.26	1.26	1.20
Electricity	14.13	12.95	13.48	13.75	13.83	13.78	14.51	14.91	15.46
Transportation	**10.28**	**10.20**	**10.21**	**10.22**	**10.22**	**10.83**	**10.75**	**10.71**	**10.66**
Primary Energy	10.25	10.18	10.19	10.19	10.19	10.80	10.72	10.68	10.63
Petroleum Products[2]	10.25	10.18	10.19	10.20	10.20	10.81	10.73	10.69	10.63
Distillate Fuel[5]	10.05	10.19	10.19	10.16	10.18	10.67	10.62	10.63	10.66
Jet Fuel[6]	6.20	5.64	5.65	5.64	5.64	6.72	6.73	6.73	6.73
Motor Gasoline[7]	11.57	11.43	11.44	11.47	11.46	12.07	11.95	11.88	11.78
Residual Fuel	3.90	3.57	3.55	3.55	3.55	3.95	3.93	3.93	3.93
Liquefied Petroleum Gas[8]	16.93	15.52	15.49	15.46	15.45	16.04	16.11	16.09	16.12
Natural Gas[9]	7.65	7.22	7.24	7.28	7.38	8.11	8.33	8.48	8.36
Ethanol (E85)[10]	17.72	21.29	21.28	21.16	20.73	23.57	23.15	22.68	21.74
Electricity	21.87	19.18	19.83	20.05	20.01	18.11	18.92	19.34	19.71
Average End-Use Energy	**10.74**	**9.99**	**10.10**	**10.17**	**10.19**	**10.88**	**11.02**	**11.12**	**11.14**
Primary Energy	8.52	8.07	8.07	8.09	8.11	8.85	8.86	8.88	8.81
Electricity	21.33	18.86	19.56	19.85	19.86	19.96	20.81	21.26	21.86
Electric Power[11]									
Fossil Fuel Average	2.14	1.85	1.99	2.39	3.52	2.15	3.07	4.04	5.58
Petroleum Products	4.73	4.28	4.58	4.88	5.83	4.94	6.05	6.85	8.24
Distillate Fuel	6.20	5.12	5.14	5.43	6.34	6.19	6.53	7.31	8.87
Residual Fuel	4.50	4.07	4.33	4.65	5.62	4.47	5.55	6.40	7.97
Natural Gas	4.78	3.93	4.04	4.32	5.11	4.65	5.32	6.06	6.95
Steam Coal	1.25	1.17	1.29	1.68	2.86	1.11	1.79	2.76	4.48

Table E3. Energy Prices by Sector and Source (Continued)

(2001 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Average Price to All Users[12]									
Petroleum Products[2]	9.54	9.44	9.47	9.48	9.49	10.23	10.20	10.18	10.15
Distillate Fuel	9.16	9.14	9.15	9.13	9.15	9.92	9.88	9.90	9.96
Jet Fuel	6.20	5.64	5.65	5.64	5.64	6.72	6.73	6.73	6.73
Liquefied Petroleum Gas	12.85	10.75	10.74	10.73	10.73	11.83	11.85	11.85	11.87
Motor Gasoline[7]	11.57	11.43	11.44	11.46	11.46	12.07	11.95	11.88	11.78
Residual Fuel	4.11	3.74	3.71	3.77	3.94	4.13	4.20	4.33	4.54
Natural Gas	6.40	5.17	5.19	5.29	5.57	5.66	5.96	6.32	6.56
Coal	1.26	1.19	1.30	1.66	2.75	1.12	1.75	2.65	4.19
Ethanol (E85)[10]	17.72	21.29	21.28	21.16	20.73	23.57	23.15	22.68	21.74
Electricity	21.33	18.86	19.56	19.85	19.86	19.96	20.81	21.26	21.86
Non-Renewable Energy Expenditures by Sector (billion 2001 dollars)									
Residential	166.71	168.69	171.43	172.93	173.22	204.81	209.45	212.83	214.61
Commercial	127.27	128.81	132.06	133.45	133.60	183.97	188.80	191.96	194.01
Industrial	135.32	138.54	140.38	141.70	142.64	192.57	197.70	201.37	201.46
Transportation	270.40	327.78	327.64	327.80	327.50	457.13	453.28	451.40	448.24
Total Non-Renewable Expenditures	699.70	763.82	771.51	775.88	776.96	1038.49	1049.23	1057.56	1058.32
Transportation Renewable Expenditures	0.01	0.05	0.05	0.05	0.05	0.13	0.13	0.13	0.13
Total Expenditures	**699.71**	**763.87**	**771.56**	**775.93**	**777.00**	**1038.62**	**1049.36**	**1057.69**	**1058.45**

[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 combined heat and power, which produces electricity and other useful thermal energy.
[4]Excludes use for lease and plant fuel.
[5]Diesel fuel containing 500 parts per million (ppm) or 15 ppm sulfur. Price includes Federal and State taxes while excluding county and local taxes.
[6]Kerosene-type jet fuel. Price 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. Price includes estimated motor vehicle fuel taxes.
[10]E85 is 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable).
[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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2001*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (September 2002). 2001 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 electric power prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2001 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998*. 2001 coal prices based on EIA, *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. 2001 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). 2001 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E4. Electricity Supply, Disposition, Prices, and Emissions

(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Generation by Fuel Type									
Electric Power Sector[1]									
Power Only[2]									
Coal	1848	2216	2129	2078	1945	2726	2305	2081	1574
Petroleum	113	44	23	23	24	58	36	34	17
Natural Gas[3]	411	677	743	776	823	1289	1637	1730	1694
Nuclear Power	769	787	787	787	794	790	790	790	797
Pumped Storage/Other	-9	-1	-1	-1	-1	-1	-1	-1	-1
Renewable Sources[4]	258	392	405	410	467	424	456	589	1046
Distributed Generation (Natural Gas)	0	1	1	1	4	7	7	7	13
Non-Utility Generation for Own Use	-21	-24	-26	-26	-26	-24	-25	-25	-25
Total	**3370**	**4091**	**4061**	**4049**	**4030**	**5270**	**5206**	**5206**	**5115**
Combined Heat and Power[5]									
Coal	33	33	24	23	23	33	23	23	19
Petroleum	7	4	4	4	4	3	4	4	3
Natural Gas	124	180	182	185	196	164	166	153	167
Renewable Sources	5	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-9	-18	-17	-17	-17	-18	-17	-17	-16
Total	**162**	**203**	**196**	**199**	**211**	**187**	**180**	**167**	**177**
Net Available to the Grid	**3532**	**4294**	**4258**	**4248**	**4240**	**5457**	**5386**	**5373**	**5291**
End-Use Sector Generation									
Combined Heat and Power[6]									
Coal	23	23	23	23	23	23	23	23	23
Petroleum	6	6	6	6	6	6	6	6	6
Natural Gas	83	107	113	114	119	187	209	213	249
Other Gaseous Fuels[7]	6	7	7	7	7	8	8	8	8
Renewable Sources[4]	31	40	40	40	40	56	56	56	56
Other[8]	11	11	11	11	11	11	11	11	11
Total	**160**	**194**	**200**	**201**	**206**	**292**	**314**	**318**	**353**
Other End-Use Generators[9]	4	5	5	5	5	6	6	6	6
Generation for Own Use	-137	-155	-159	-159	-162	-215	-229	-231	-251
Total Sales to the Grid	**27**	**44**	**46**	**47**	**49**	**83**	**91**	**93**	**108**
Net Imports	**20**	**32**	**37**	**40**	**41**	**8**	**9**	**10**	**9**
Electricity Sales by Sector									
Residential	1201	1444	1432	1429	1428	1742	1720	1714	1696
Commercial	1197	1468	1458	1456	1456	1982	1959	1958	1943
Industrial	994	1162	1156	1155	1151	1462	1447	1444	1412
Transportation	22	27	27	27	27	41	41	41	41
Total	**3414**	**4100**	**4073**	**4066**	**4063**	**5228**	**5167**	**5157**	**5093**
End-Use Prices[10] (2001 cents per kilowatthour)									
Residential	8.7	7.7	8.0	8.1	8.1	8.0	8.3	8.5	8.7
Commercial	7.9	6.8	7.1	7.1	7.1	7.4	7.7	7.8	8.0
Industrial	4.8	4.4	4.6	4.7	4.7	4.7	4.9	5.1	5.3
Transportation	7.5	6.5	6.8	6.8	6.8	6.2	6.5	6.6	6.7
All Sectors Average	**7.3**	**6.4**	**6.7**	**6.8**	**6.8**	**6.8**	**7.1**	**7.3**	**7.5**
Prices by Service Category[10] (2001 cents per kilowatthour)									
Generation	4.7	3.9	4.1	4.2	4.2	4.3	4.6	4.7	4.9
Transmission	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7
Distribution	2.0	2.0	2.0	2.0	2.0	1.9	1.9	1.9	1.9

Table E4. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Emissions									
Sulfur Dioxide (million tons)	10.64	9.66	5.00	5.06	5.28	8.95	3.50	3.45	3.34
Nitrogen Oxide (million tons)	4.75	3.93	1.82	1.81	1.74	4.11	1.71	1.65	1.46
Mercury (tons)	49.49	52.56	17.83	17.79	17.05	54.33	10.00	10.00	10.00

[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.
[7]Other gaseous fuels include refinery and still gas.
[8]Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur and miscellaneous technologies.
[9]Other end-use generators include 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.
[10]Prices represent average revenue per kilowatthour.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Source: 2001 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 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002), and supporting databases. 2001 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2001 prices: EIA, National Energy Modeling System run IMBASE.D080503A. **Projections**: EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Electric PowerSector[2]									
Power Only[3]									
Coal Steam	305.3	306.8	298.5	294.4	287.7	372.1	318.6	295.4	270.0
Other Fossil Steam[4]	133.8	89.0	76.8	76.1	86.6	82.1	71.7	63.0	72.5
Combined Cycle	43.2	135.2	148.2	149.0	146.0	239.2	292.4	312.7	281.9
Combustion Turbine/Diesel	97.6	136.8	133.7	133.9	127.0	192.8	191.9	189.2	157.1
Nuclear Power[5]	98.2	98.3	98.3	98.3	99.3	98.6	98.6	98.6	99.6
Pumped Storage	19.9	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	90.4	97.0	99.0	99.9	116.6	102.9	109.2	142.5	231.9
Distributed Generation[7]	0.0	1.6	1.5	1.5	1.6	16.3	17.0	15.4	13.4
Total	**788.3**	**885.1**	**876.4**	**873.5**	**885.4**	**1124.7**	**1119.9**	**1137.4**	**1147.0**
Combined Heat and Power[8]									
Coal Steam	5.2	5.1	3.1	3.1	3.1	5.1	3.1	3.1	3.0
Other Fossil Steam[4]	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	22.6	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	4.6	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Renewable Sources[6]	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**33.7**	**44.7**	**42.7**	**42.7**	**42.7**	**44.7**	**42.7**	**42.7**	**42.6**
Total Electric Power Industry	**822.0**	**929.8**	**919.1**	**916.2**	**928.1**	**1169.4**	**1162.5**	**1180.1**	**1189.6**
Cumulative Planned Additions[9]									
Coal Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
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	83.1	83.1	83.1	83.1	83.1	83.1	83.1	83.1
Combustion Turbine/Diesel	0.0	31.5	31.5	31.5	31.5	31.5	31.5	31.5	31.5
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Fuel Cells	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Renewable Sources[6]	0.0	4.9	4.9	4.9	4.9	6.6	6.6	6.6	6.6
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**120.0**	**120.0**	**120.0**	**120.0**	**121.8**	**121.8**	**121.8**	**121.8**
Cumulative Unplanned Additions[9]									
Coal Steam	0.0	8.2	2.5	1.6	0.0	76.5	27.1	6.3	0.0
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	19.4	32.5	33.8	29.6	123.4	177.2	198.2	166.0
Combustion Turbine/Diesel	0.0	13.8	14.6	14.4	6.6	75.6	76.4	73.6	43.5
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	1.3	3.3	4.3	20.9	5.6	11.9	45.2	134.6
Distributed Generation[7]	0.0	1.6	1.5	1.5	1.6	16.3	17.0	15.4	13.4
Total	**0.0**	**44.3**	**54.4**	**55.6**	**58.8**	**297.4**	**309.6**	**338.8**	**357.5**
Cumulative Total Additions	**0.0**	**164.3**	**174.4**	**175.6**	**178.8**	**419.2**	**431.4**	**460.6**	**479.2**
Cumulative Retirements[10]									
Coal Steam	0.0	6.9	11.4	14.6	19.8	9.8	16.0	18.4	37.6
Other Fossil Steam[4]	0.0	43.3	55.5	56.2	45.7	50.2	60.6	69.2	59.8
Combined Cycle	0.0	1.2	1.4	1.9	0.6	1.2	1.8	2.6	1.1
Combustion Turbine/Diesel	0.0	5.6	9.5	9.2	8.2	11.4	13.1	13.1	15.0
Nuclear Power	0.0	2.8	2.8	2.8	1.8	3.8	3.8	3.8	2.8
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**	**60.0**	**80.8**	**84.9**	**76.2**	**76.5**	**95.6**	**107.3**	**116.4**

Table E5. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
End-Use Sector									
Combined Heat and Power[11]									
Coal	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Petroleum	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Natural Gas	14.5	17.3	18.0	18.2	18.8	28.2	31.3	31.8	36.7
Other Gaseous Fuels	2.1	2.2	2.2	2.2	2.2	2.3	2.3	2.3	2.3
Renewable Sources[6]	4.7	6.2	6.2	6.2	6.2	9.0	9.0	9.0	9.0
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	**27.7**	**32.1**	**32.9**	**33.0**	**33.6**	**46.0**	**49.1**	**49.6**	**54.4**
Other End-Use Generators[12]									
Renewable Sources[13]	1.1	1.5	1.5	1.5	1.5	2.0	2.1	2.1	2.1
Cumulative Additions[9]									
Combined Heat and Power[11]	0.0	4.4	5.1	5.3	5.9	18.4	21.3	21.9	26.6
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.4	0.9	0.9	0.9	0.9

[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 4.3 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power.
[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, 2001.
[10]Cumulative total retirements after December 31, 2001.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[12]Other end-use generators include 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.
[13]See Table E9 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model estimates and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators to be consistent with capability for electric utility generators.
Source: 2001 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E6. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Production									
Dry Gas Production[1]	19.45	21.68	21.92	22.02	22.38	26.44	26.87	26.64	26.88
Supplemental Natural Gas[2]	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Net Imports	**3.73**	**4.86**	**4.95**	**5.09**	**5.24**	**8.07**	**9.68**	**10.12**	**9.81**
Canada	3.61	4.22	4.29	4.34	4.36	5.20	5.32	5.34	5.28
Mexico	-0.13	-0.20	-0.20	-0.20	-0.20	0.58	0.62	0.63	0.65
Liquefied Natural Gas	0.26	0.84	0.86	0.95	1.08	2.29	3.74	4.15	3.88
Total Supply	**23.26**	**26.64**	**26.96**	**27.21**	**27.72**	**34.60**	**36.64**	**36.86**	**36.78**
Consumption by Sector									
Residential	4.81	5.48	5.47	5.47	5.46	6.21	6.15	6.13	6.15
Commercial	3.24	3.64	3.63	3.63	3.62	4.39	4.36	4.33	4.38
Industrial[3]	7.53	8.82	8.85	8.85	8.86	10.97	11.05	11.02	11.22
Electric Generators[4]	5.30	6.82	7.09	7.36	7.84	10.54	12.56	12.89	12.56
Transportation[5]	0.01	0.06	0.06	0.06	0.06	0.11	0.11	0.11	0.11
Pipeline Fuel	0.61	0.76	0.78	0.78	0.79	1.00	1.02	1.01	1.02
Lease and Plant Fuel[6]	1.17	1.34	1.35	1.36	1.37	1.69	1.71	1.70	1.71
Total	**22.67**	**26.92**	**27.24**	**27.49**	**28.00**	**34.91**	**36.96**	**37.18**	**37.13**
Natural Gas to Liquids	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Discrepancy[7]	**0.59**	**-0.28**	**-0.28**	**-0.28**	**-0.28**	**-0.31**	**-0.31**	**-0.32**	**-0.35**

[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 consumption for combined heat and power, which produces electricity and other useful thermal energy.
[4]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.
[5]Compressed natural gas used as vehicle fuel.
[6]Represents natural gas used in the field gathering and processing plant machinery.
[7]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, 2001 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). 2001 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E7. Oil and Gas Supply

Production and Supply	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Crude Oil									
Lower 48 Average Wellhead Price[1] (2001 dollars per barrel)	**22.91**	**23.88**	**23.90**	**23.88**	**23.88**	**26.18**	**26.22**	**26.18**	**26.15**
Production (million barrels per day)[2]									
U.S. Total	**5.80**	**5.64**	**5.64**	**5.64**	**5.64**	**5.33**	**5.33**	**5.33**	**5.35**
Lower 48 Onshore	3.13	2.47	2.47	2.47	2.47	1.92	1.92	1.92	1.92
Lower 48 Offshore	1.71	2.52	2.52	2.53	2.53	2.24	2.24	2.24	2.26
Alaska	0.97	0.64	0.64	0.64	0.64	1.17	1.17	1.17	1.17
Lower 48 End of Year Reserves (billion barrels)[2]	**19.48**	**17.72**	**17.73**	**17.74**	**17.74**	**15.11**	**15.13**	**15.10**	**15.17**
Natural Gas									
Lower 48 Average Wellhead Price[1] (2001 dollars per thousand cubic feet)	**4.12**	**3.42**	**3.42**	**3.47**	**3.57**	**3.97**	**4.16**	**4.33**	**4.24**
Dry Production (trillion cubic feet)[3]									
U.S. Total	**19.45**	**21.68**	**21.92**	**22.02**	**22.38**	**26.44**	**26.87**	**26.64**	**26.88**
Lower 48 Onshore	13.72	15.75	15.86	16.01	16.35	17.85	18.28	18.23	18.24
Associated-Dissolved[4]	1.77	1.37	1.37	1.37	1.37	1.13	1.13	1.13	1.13
Non-Associated	11.94	14.38	14.50	14.65	14.98	16.72	17.14	17.10	17.11
Conventional	6.54	7.12	7.10	7.16	7.29	7.06	7.18	7.18	7.18
Unconventional	5.40	7.26	7.39	7.49	7.69	9.67	9.96	9.92	9.93
Lower 48 Offshore	5.30	5.45	5.58	5.53	5.56	5.73	5.74	5.56	5.79
Associated-Dissolved[4]	1.08	0.96	0.96	0.96	0.96	0.83	0.83	0.82	0.83
Non-Associated	4.22	4.49	4.62	4.57	4.60	4.91	4.92	4.74	4.96
Alaska	0.43	0.48	0.48	0.48	0.48	2.85	2.85	2.85	2.85
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**174.04**	**186.40**	**186.43**	**185.83**	**186.03**	**190.76**	**190.10**	**190.01**	**189.92**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.08**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**	**0.10**
Total Lower 48 Wells (thousands)	**33.94**	**25.76**	**25.76**	**25.92**	**26.26**	**27.50**	**28.13**	**28.40**	**28.11**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reserves either as free gas (associated) or as gas in solution with crude oil (dissolved).
[5]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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2001,* DOE/EIA-0340(2001)/1 (Washington, DC, June 2002). 2001 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2002/08) (Washington, DC, August 2002). Other 2001 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E8. Coal Supply, Disposition, and Prices

(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Production[1]									
Appalachia	443	420	427	427	398	420	404	397	315
Interior	147	155	137	139	143	158	121	149	108
West	548	666	624	600	556	875	706	585	508
East of the Mississippi	539	527	522	524	499	542	509	519	401
West of the Mississippi	599	713	666	642	599	911	722	613	530
Total	**1138**	**1240**	**1188**	**1166**	**1097**	**1453**	**1230**	**1131**	**931**
Net Imports									
Imports	20	20	20	11	11	28	28	10	10
Exports	49	34	34	34	34	24	26	24	24
Total	**-29**	**-14**	**-14**	**-23**	**-23**	**4**	**2**	**-13**	**-13**
Total Supply[2]	**1109**	**1227**	**1174**	**1142**	**1075**	**1457**	**1232**	**1118**	**918**
Consumption by Sector									
Residential and Commercial	4	5	5	5	5	5	5	5	5
Industrial[3]	63	67	67	67	67	71	71	71	71
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0
Coke Plants	26	24	24	24	24	18	18	18	18
Electric Generators[4]	957	1136	1085	1053	980	1369	1143	1041	813
Total	**1050**	**1232**	**1180**	**1149**	**1076**	**1463**	**1238**	**1136**	**908**
Discrepancy and Stock Change[5]	**59**	**-5**	**-6**	**-6**	**-1**	**-7**	**-6**	**-19**	**10**
Average Minemouth Price									
(2001 dollars per short ton)	17.59	15.06	15.46	15.70	15.50	14.22	14.92	15.32	13.99
(2001 dollars per million Btu)	0.83	0.73	0.74	0.75	0.74	0.70	0.72	0.73	0.67
Delivered Prices (2001 dollars per short ton)[6]									
Industrial	32.83	30.05	29.96	30.04	29.79	27.91	27.28	27.13	26.07
Coke Plants	46.42	41.25	41.30	41.39	41.29	36.77	36.74	36.63	36.70
Electric Generators									
(2001 dollars per short ton)	25.05	23.71	26.41	34.53	58.49	22.17	36.76	57.14	91.50
(2001 dollars per million Btu)	1.25	1.17	1.29	1.68	2.86	1.11	1.79	2.76	4.48
Average	**26.05**	**24.40**	**26.91**	**34.42**	**56.31**	**22.63**	**36.21**	**54.92**	**85.27**
Exports[7]	36.97	32.68	32.78	32.99	32.58	30.40	29.35	30.06	29.61

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 10.1 million tons in 2000 and 10.6 million tons in 2001.

[2]Production plus net imports and 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 2001 are model results and may differ slightly from official EIA data reports.

Sources: 2001 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2001*, DOE/EIA-0121(2001/4Q) (Washington, DC, May 2002) and EIA, AEO2003 National Energy Modeling System run IMBASE.D080503A. **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E9. Coal Production by Region and Type
(Million Short Tons)

Supply Regions and Coal Types	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P No Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Northern Appalachia	**153.6**	**135.2**	**140.9**	**139.3**	**127.9**	**143.2**	**115.5**	**133.1**	**100.9**
Medium Sulfur (Premium)[1]	3.8	2.5	2.5	2.5	2.5	2.4	2.4	2.4	2.4
Low Sulfur (Bituminous)[2]	0.4	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0
Medium Sulfur (Bituminous)[2]	75.2	67.1	66.2	66.1	61.5	70.6	62.1	63.5	49.4
High Sulfur (Bituminous)	63.6	54.2	62.4	60.8	54.3	58.8	41.3	57.6	39.5
High Sulfur (Gob)[3]	10.6	11.4	9.7	9.7	9.7	11.4	9.7	9.7	9.7
Central Appalachia	**267.0**	**264.5**	**267.6**	**269.8**	**253.1**	**261.3**	**272.7**	**249.2**	**202.3**
Medium Sulfur (Premium)[1]	38.9	31.9	31.7	32.4	31.7	24.2	24.2	24.2	24.2
Low Sulfur (Bituminous)	71.2	73.6	76.2	75.9	68.1	72.1	86.0	74.8	54.7
Medium Sulfur (Bituminous)	156.8	159.0	159.7	161.4	153.3	165.0	162.5	150.1	123.3
Southern Appalachia	**22.8**	**20.1**	**18.2**	**18.3**	**17.4**	**15.3**	**15.4**	**15.1**	**12.0**
Low Sulfur (Premium)[1]	6.7	6.0	6.0	6.1	6.0	4.2	4.2	4.1	4.1
Low Sulfur (Bituminous)	5.9	4.0	3.2	3.3	3.8	3.5	4.6	3.8	2.7
Medium Sulfur (Bituminous)	10.2	10.0	9.0	8.9	7.6	7.6	6.6	7.2	5.2
Eastern Interior	**96.0**	**107.4**	**95.0**	**96.6**	**100.2**	**122.4**	**104.9**	**121.3**	**85.8**
Medium Sulfur (Bituminous)	33.6	33.7	32.3	32.5	31.3	41.3	50.4	47.5	33.1
High Sulfur (Bituminous)	61.8	69.7	59.7	61.1	65.6	77.4	51.6	70.9	49.8
Medium Sulfur (Lignite)	0.6	4.1	3.1	3.1	3.4	3.7	2.9	2.9	2.9
Western Interior High Sulfur (Bituminous)	**2.4**	**2.5**	**1.3**	**1.2**	**1.5**	**1.8**	**0.4**	**0.8**	**0.7**
Gulf	**48.6**	**45.1**	**40.8**	**40.8**	**41.4**	**33.7**	**15.5**	**26.6**	**21.1**
Medium Sulfur (Lignite)	33.4	28.0	29.8	30.2	27.4	20.3	12.1	21.1	16.3
High Sulfur (Lignite)	15.2	17.1	11.1	10.6	14.0	13.4	3.4	5.5	4.8
Dakota Medium Sulfur (Lignite)	**30.8**	**31.6**	**30.9**	**31.0**	**30.9**	**33.6**	**20.0**	**20.0**	**19.9**
Powder/Green River	**407.5**	**511.4**	**464.6**	**439.8**	**402.7**	**705.5**	**536.7**	**436.5**	**379.9**
Low Sulfur (Bituminous)	0.0	1.6	1.6	1.6	1.6	0.8	0.6	0.6	1.0
Low Sulfur (Sub-Bituminous)	375.1	483.2	432.7	415.1	380.6	659.9	519.2	416.4	368.5
Medium Sulfur (Sub-Bituminous)	32.5	26.6	30.3	23.1	20.5	44.8	16.9	19.4	10.4
Rocky Mountain	**60.3**	**81.7**	**88.6**	**89.0**	**82.9**	**98.9**	**109.5**	**91.5**	**71.4**
Low Sulfur (Bituminous)	50.5	72.5	79.4	79.8	73.7	92.4	103.0	84.9	64.9
Low Sulfur (Sub-Bituminous)	9.8	9.2	9.2	9.2	9.1	6.5	6.5	6.5	6.5
Arizona/New Mexico	**43.0**	**34.8**	**34.0**	**33.6**	**33.2**	**30.8**	**33.1**	**30.8**	**30.8**
Low Sulfur (Bituminous)	20.9	16.3	15.4	15.1	14.6	14.2	16.5	14.2	14.2
Medium Sulfur (Bituminous)	0.7	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Medium Sulfur (Sub-bituminous)	21.5	11.5	11.5	11.5	11.5	9.5	9.5	9.5	9.5
Washington/Alaska Medium Sulfur (Sub-Bituminous)	**6.1**	**6.2**	**6.2**	**6.2**	**6.2**	**6.3**	**6.3**	**6.3**	**6.3**

Table E9. Coal Production by Region and Type (Continued)

(Million Short Tons)

Supply Regions and Coal Types	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Subtotals: All Regions									
Premium Metallurgical[1]	49.5	40.4	40.2	41.0	40.2	30.8	30.8	30.7	30.7
Bituminous	553.2	571.2	573.6	575.0	544.0	612.7	592.8	583.0	445.6
Sub-Bituminous	445.0	536.7	489.9	465.1	427.9	727.0	558.5	458.3	401.4
Lignite	90.6	92.1	84.5	84.5	85.4	82.4	48.1	59.2	53.6
Low Sulfur	540.5	666.4	624.0	606.2	557.7	853.6	740.6	605.4	516.7
Medium Sulfur	444.2	419.1	420.0	415.9	394.7	436.4	383.2	381.2	310.1
High Sulfur	153.6	154.9	144.1	143.4	145.1	162.9	106.4	144.5	104.4
Underground	380.2	405.4	406.8	408.9	385.3	452.8	435.8	427.7	323.6
Surface	758.1	835.0	781.3	756.7	712.1	1000.1	794.3	703.5	607.6
U.S. Total	**1138.3**	**1240.4**	**1188.2**	**1165.6**	**1097.5**	**1452.9**	**1230.2**	**1131.2**	**931.2**

[1]"Premium" coal is used to make metallurgical coke.
[2]Includes Pennsylvania anthracite.
[3]Waste coal delivered to Independent Power Producers (IPP) that is not included in other Energy Information Administration coal production tables. The totals for this table include this waste coal tonnage.

Northern Appalachia: Pennsylvania, Maryland, Ohio, Northern West Virginia (Pennsylvania anthracite is included under low and medium sulfur bituminous).
Central Appalachia: Southern West Virginia, Virginia, Eastern Kentucky.
Southern Appalachia: Alabama, Tennessee.
Eastern Interior: Illinois, Indiana, Mississippi, Western Kentucky.
Western Interior (Bituminous only): Iowa, Missouri, Kansas, Oklahoma, Arkansas, Texas.
Gulf (Lignite only): Texas, Louisiana, Arkansas.
Dakota: North Dakota, Eastern Montana (Lignite only).
Powder/Green River: Wyoming, Montana (Sub-Bituminous and Bituminous)
Rocky Mountain: Colorado, Utah.
Sulfur Definitions:
Low Sulfur: 0 - 0.60 pounds of sulfur per million British thermal unit.
Medium Sulfur: 0.61 - 1.67 pounds of sulfur per million British thermal unit.
High Sulfur: Over 1.67 pounds of sulfur per million British thermal unit.
Note: Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E10. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Electric Power Sector[1]									
Net Summer Capacity									
Conventional Hydropower	78.10	78.66	78.66	78.66	78.66	78.65	78.65	78.65	78.65
Geothermal[2]	2.83	3.81	3.95	3.90	4.22	5.94	6.51	7.07	8.14
Municipal Solid Waste[3]	3.25	3.99	3.99	4.12	4.79	4.39	4.44	4.68	5.19
Wood and Other Biomass[4]	1.80	2.09	2.09	2.09	3.37	2.36	2.87	11.60	63.22
Solar Thermal	0.33	0.44	0.44	0.44	0.44	0.50	0.50	0.50	0.50
Solar Photovoltaic[5]	0.02	0.10	0.10	0.10	0.10	0.36	0.36	0.36	0.36
Wind	4.29	8.13	10.01	10.88	25.28	10.98	16.13	39.94	76.14
Total	**90.62**	**97.22**	**99.24**	**100.20**	**116.85**	**103.19**	**109.45**	**142.79**	**232.20**
Generation (billion kilowatthours)									
Conventional Hydropower	213.82	300.90	300.89	300.90	300.90	300.36	300.35	300.36	300.37
Geothermal[2]	13.81	21.99	23.13	22.74	25.28	39.58	44.15	48.45	57.32
Municipal Solid Waste[3]	19.55	28.52	28.52	29.56	34.80	31.61	31.98	33.92	37.92
Wood and Other Biomass[4]	9.38	20.88	26.41	27.42	27.15	22.02	30.21	71.11	394.33
Dedicated Plants	7.67	12.44	12.43	12.36	16.92	14.09	16.55	67.45	394.33
Cofiring	1.71	8.44	13.98	15.06	10.23	7.94	13.66	3.66	0.00
Solar Thermal	0.49	0.77	0.77	0.77	0.77	0.97	0.97	0.97	0.97
Solar Photovoltaic[5]	0.00	0.24	0.24	0.24	0.24	0.88	0.88	0.88	0.88
Wind	5.78	22.55	29.14	32.16	81.88	32.68	51.32	137.48	257.71
Total	**262.85**	**395.86**	**409.10**	**413.79**	**471.02**	**428.11**	**459.86**	**593.17**	**1049.50**
End- Use Sector									
Net Summer Capacity									
Combined Heat and Power[6]									
Municipal Solid Waste	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
Biomass	4.41	5.92	5.91	5.91	5.91	8.74	8.73	8.73	8.71
Total	**4.69**	**6.21**	**6.20**	**6.19**	**6.19**	**9.03**	**9.01**	**9.01**	**8.99**
Other End-Use Generators[7]									
Conventional Hydropower[8]	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.38	0.38	0.38	0.38	0.96	0.96	0.97	0.96
Total	**1.12**	**1.47**	**1.47**	**1.47**	**1.47**	**2.05**	**2.06**	**2.06**	**2.05**
Generation (billion kilowatthours)									
Combined Heat and Power[6]									
Municipal Solid Waste	2.46	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
Biomass	28.67	37.51	37.46	37.44	37.42	53.98	53.88	53.89	53.77
Total	**31.13**	**39.66**	**39.61**	**39.59**	**39.57**	**56.13**	**56.03**	**56.04**	**55.92**
Other End-Use Generators[7]									
Conventional Hydropower[8]	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23	4.23
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.02	0.82	0.82	0.82	0.82	2.02	2.04	2.04	2.02
Total	**4.25**	**5.05**	**5.05**	**5.05**	**5.05**	**6.25**	**6.27**	**6.28**	**6.26**

[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]Includes projections for energy crops after 2010.
[5]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2001 Table 10.6 for estimates of 1989-2000 PV shipments, including exports, for both grid-connected and off-grid applications.
[6]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[7]Includes 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 2001 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2003. 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: 2001 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2001 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E11. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons Carbon Equivalent per Year)

Sector and Source	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Residential									
Petroleum	27.2	27.6	27.6	27.6	27.6	25.0	25.0	25.0	25.0
Natural Gas	71.1	81.1	81.0	80.9	80.8	91.9	91.0	90.7	91.0
Coal	0.3	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3
Electricity	215.1	245.7	237.5	233.6	222.7	289.5	263.5	247.9	204.3
Total	**313.8**	**354.8**	**346.5**	**342.5**	**331.5**	**406.7**	**379.9**	**364.0**	**320.7**
Commercial									
Petroleum	14.0	13.7	13.7	13.7	13.7	14.1	14.3	14.3	14.3
Natural Gas	48.0	53.8	53.8	53.7	53.6	65.0	64.6	64.1	64.8
Coal	2.3	2.4	2.4	2.4	2.5	2.8	2.8	2.8	2.8
Electricity	214.5	249.8	241.9	237.9	226.9	329.5	300.1	283.4	234.0
Total	**278.8**	**319.8**	**311.8**	**307.8**	**296.7**	**411.3**	**381.8**	**364.5**	**315.9**
Industrial[1]									
Petroleum	97.9	98.0	97.7	97.9	97.8	109.4	109.8	110.5	108.8
Natural Gas[2]	123.4	147.9	148.5	148.4	148.9	184.0	185.5	184.8	188.2
Coal	52.1	56.5	56.4	56.4	56.3	56.2	56.1	56.3	55.8
Electricity	178.1	197.7	191.8	188.8	179.5	243.0	221.7	208.9	170.1
Total	**451.5**	**500.0**	**494.5**	**491.4**	**482.5**	**592.6**	**573.0**	**560.4**	**522.9**
Transportation									
Petroleum[3]	501.4	611.4	610.6	610.3	609.9	802.6	801.5	801.1	799.5
Natural Gas[4]	9.2	12.1	12.3	12.4	12.5	16.4	16.6	16.5	16.6
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	3.9	4.6	4.5	4.5	4.2	6.9	6.3	6.0	5.0
Total	**514.5**	**628.2**	**627.5**	**627.2**	**626.6**	**826.0**	**824.5**	**823.6**	**821.1**
Total Carbon Dioxide Emissions by Delivered Fuel									
Petroleum[3]	640.5	750.7	749.7	749.5	749.1	951.1	950.5	950.8	947.6
Natural Gas	251.7	294.9	295.7	295.4	295.7	357.3	357.7	356.1	360.6
Coal	54.7	59.3	59.2	59.2	59.1	59.3	59.3	59.4	59.0
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	611.6	697.8	675.7	664.7	633.3	868.9	791.7	746.2	613.4
Total	**1558.6**	**1802.7**	**1780.3**	**1768.9**	**1737.2**	**2236.6**	**2159.2**	**2112.5**	**1980.5**
Electric Generators[6]									
Petroleum	27.5	10.8	6.1	6.1	6.3	13.4	8.0	7.7	5.4
Natural Gas	77.7	100.0	104.0	108.0	115.1	154.7	184.3	189.1	183.5
Coal	506.4	587.0	565.6	550.7	511.8	700.8	599.4	549.3	424.5
Total	**611.6**	**697.8**	**675.7**	**664.7**	**633.3**	**868.9**	**791.7**	**746.2**	**613.4**
Total Carbon Dioxide Emissions by Primary Fuel[7]									
Petroleum[3]	668.0	761.5	755.8	755.7	755.4	964.5	958.5	958.5	952.9
Natural Gas	329.4	395.0	399.7	403.4	410.8	512.0	542.0	545.2	544.1
Coal	561.1	646.3	624.8	609.9	571.0	760.1	658.7	608.7	483.4
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**1558.6**	**1802.7**	**1780.3**	**1768.9**	**1737.2**	**2236.6**	**2159.2**	**2112.5**	**1980.5**
Carbon Dioxide Emissions (tons carbon equivalent per person)	**5.6**	**6.0**	**5.9**	**5.9**	**5.8**	**6.6**	**6.4**	**6.2**	**5.9**

[1]Fuel consumption includes energy for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lease and plant fuel.
[3]This includes international bunker fuel, which by convention are excluded from the international accounting of carbon dioxide emissions. In the years from 1990 through 2000, international bunker fuels accounted for 24 to 30 million metric tons carbon equivalent of carbon dioxide annually.
[4]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[5]Includes methanol and liquid hydrogen.
[6]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal solid waste because under international guidelines these are accounted for as waste, not energy.
[7]Emissions from electric power generators are distributed to the primary fuels.
Note: Totals may not equal sum of components due to independent rounding. Data for 2001 are model results and may differ slightly from official EIA data reports.
Sources: 2001 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002). **Projections:** EIA, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.

Table E12. Emissions, Allowance Prices, and Emission Controls in the Electric Power Sector

Supply and Disposition	2001	Projections							
		2010				2025			
		Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets	Reference	Carper 4P High Offsets	Carper 4P Mid Offsets	Carper 4P No Offsets
Emissions									
Nitrogen Oxides (million tons)	4.75	3.93	1.82	1.81	1.74	4.11	1.71	1.65	1.46
Sulfur Dioxide (million tons)	10.64	9.66	5.00	5.06	5.28	8.95	3.50	3.45	3.34
From Coal	10.05	9.47	4.93	4.99	5.21	8.75	3.47	3.42	3.32
From Oil/Other	0.60	0.19	0.06	0.06	0.07	0.20	0.03	0.03	0.02
Mercury (tons)	49.49	52.56	17.83	17.79	17.05	54.33	10.00	10.00	10.00
Carbon Dioxide (million metric tons carbon equivalent)	611.57	697.82	675.69	664.75	633.27	868.91	791.67	746.19	613.36
Allowance Prices									
Nitrogen Oxides (2001 dollars per ton)									
Regional/Seasonal	0.00	4741.70	0.00	0.00	0.00	6207.45	0.00	0.00	0.00
East/Annual	0.00	0.00	2117.95	1879.43	1791.53	0.00	2082.08	1936.69	0.00
West/Annual	0.00	0.00	2117.98	1879.46	1791.56	0.00	2082.10	1936.71	0.00
Sulfur Dioxide (2001 dollars per ton)	76.93	100.52	926.32	1000.58	680.59	51.70	1547.67	1645.23	1292.49
Mercury (thousand 2001 dollars per pound)	0.00	0.00	0.00	0.00	0.00	0.00	22.93	19.37	9.91
Carbon Dioxide (2001 dollars per million metric ton carbon equivalent)	0.00	0.00	4.10	19.59	66.18	0.00	26.17	65.44	135.23
Retrofits (gigawatts)									
Scrubber[6]									
Planned	1.49	20.65	20.65	20.65	20.65	22.82	22.82	22.82	22.82
Unplanned	0.00	0.00	65.78	60.07	44.44	0.00	93.00	92.93	49.61
Total	1.49	20.65	86.43	80.72	65.10	22.82	115.81	115.75	72.43
Nitrogen Oxides Controls									
Combustion	0.00	16.01	27.40	27.29	26.99	17.83	30.86	29.67	29.32
SCR Post-combustion	0.00	79.20	152.33	149.81	140.11	84.52	166.74	161.50	140.11
SNCR Post-combustion	0.00	16.67	10.64	9.49	14.54	47.18	17.56	19.43	16.36
Coal Production by Sulfur Category (million tons)									
Low Sulfur (< .61 lbs per million Btu)	540.47	666.41	623.99	606.22	557.65	853.64	740.60	605.44	516.71
Medium Sulfur	444.21	419.09	420.04	415.89	394.75	436.35	383.16	381.24	310.05
High Sulfur (> 1.67 lbs per million Btu)	153.63	154.89	144.14	143.44	145.07	162.92	106.39	144.50	104.45
Interregional Sulfur Dioxide Allowances									
Target (million tons)	9.48	8.95	4.50	4.50	4.50	8.95	2.25	2.25	2.25
Cumulative Banked Allowances	9.23	1.03	20.64	20.35	19.39	0.00	1.98	1.42	2.05
Coal Characteristics									
SO_2 Content (lbs per million Btu)	1.85	1.73	1.74	1.77	1.82	1.62	1.52	1.78	1.73
Mercury Content (lbs per trillion Btu)	7.50	7.25	7.23	7.31	7.38	6.99	6.79	7.13	7.37
ACI Controls (gigawatts)									
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	122.79	126.81	125.35	0.00	132.18	140.10	131.99
ACI Mercury Removal (tons)	**0.00**	**0.00**	**21.03**	**20.52**	**20.34**	**0.00**	**25.88**	**23.74**	**19.71**
Allowance Revenues (billion 2001 dollars)									
Nitrogen Oxides	0.00	2.24	3.96	3.52	3.35	2.94	3.54	3.29	0.09
Sulfur Dioxide	2.02	1.74	6.05	6.01	3.07	1.10	7.06	5.98	3.15
Mercury	0.00	0.00	0.00	0.00	0.00	0.00	1.09	0.75	0.39
Carbon	0.00	0.00	2.77	13.02	41.91	0.00	20.71	48.83	82.94
Total	**2.02**	**3.98**	**12.79**	**22.54**	**48.34**	**4.03**	**32.41**	**58.86**	**86.57**

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 2001 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2003 National Energy Modeling System runs IMBASE.D080503A, IMCA4P.D080703A, IMCA4PLO.D080703B, IMCA4PNO.D080703A.