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Analysis of S. 1844, the Clear Skies Act of 2003; S. 843, the Clean Air Planning Act of 2003; and S. 366, the Clean Power Act of 2003

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Energy Information Administration
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Background

Senator James M. Inhofe requested that the Energy Information Administration (EIA) undertake analysis of S.843, the Clean Air Planning Act of 2003, introduced by Senator Thomas Carper; S.366, the Clean Power Act of 2003, introduced by Senator James Jeffords; and S.1844, the Clear Skies Act of 2003, introduced by Senator James M. Inhofe. The EIA received this request on March 19, 2004. This Service Report responds to his request.

The emissions targets and implementation timetables for the bills are summarized in Table ES1. All three bills implement emissions targets on power sector emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury (Hg). The Clean Air Planning Act and the Clean Power Act also call for limits on power sector carbon dioxide (CO_2) emissions. Under the Clean Air Planning Act, greenhouse gas emission reductions outside of the power sector, referred to as offsets, can be used to meet the emission targets for CO_2.

Table ES1. Emission Targets in S.366, S.843, and S.1844

Emission	S. 366, Clean Power Act (Jeffords)	S. 843, Clean Air Planning Act (Carper)	S. 1844, Clear Skies Act (Inhofe)
Nitrogen Oxides (NO_x)	1.51 million tons in 2009	1.87 million tons in 2009 1.7 million tons in 2013	2.19 million tons in 2008 1.79 million tons in 2018[a]
Sulfur Dioxide (SO_2)	2.25 million tons in 2009[b]	4.5 million tons in 2009 3.5 million tons in 2013 2.25 million tons in 2016	4.4 million tons in 2010 3.0 million tons in 2018
Mercury (Hg)	5 tons in 2008[c]	24 tons in 2009 10 tons in 2013[d]	34 tons in 2010 15 tons in 2018
Carbon Dioxide (CO_2)	1,863 million metric tons CO_2 (508 million metric tons carbon equivalent) in 2009[e]	2,332 million metric tons CO_2 (636 million metric tons carbon equivalent) in 2009 2,244 million metric tons CO_2 (612 million metric tons carbon equivalent) in 2013[f]	No cap

a. Limit on NO_x emissions is split between 2 regions: 1.47 million tons in Zone 1 (the East) in 2008 to 2017, and 0.72 million tons in Zone 2 (the West) in 2008 to 2017; 1.07 million tons in Zone 1 (the East) in 2018, and 0.72 million tons in Zone 2 (the West) in 2018.
b. Limit on SO_2 emissions is split between 2 regions, 0.275 million tons in the West and 1.975 million tons for the non-Western region.
c. Minimum facility-specific reductions without trading are required.
d. Minimum facility-specific reductions of between 50 percent (2009 to 2012) and 70 percent (after 2012) are required.
e. This is the 1990 level of CO_2 emissions from the electricity sector.
f. 2009 to 2012 limits are based on EIA projected emissions for 2006 from the *Annual Energy Outlook 2004*. The limit for 2013 and subsequent years is based on actual 2001 emissions.

Sources: S. 366: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s366is.txt.pdf,
S. 843: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf,
S. 1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s1844is.txt.pdf.

All three bills cover emissions from larger generators that generate power for sale. This includes central station generators and generators at customer sites that sell power they do not use for their own needs. The Clear Skies and Clean Air Planning Acts cover generating facilities 25 megawatts and larger, while the Clean Power Act covers facilities

15 megawatts and larger. The bills have differing provisions regarding the coverage of combined heat and power facilities that generate some power for sale.

The bills generally rely on emissions cap and trade programs to achieve the required reductions. Under such programs, allowances will be allocated and covered generators will have to submit one allowance for each unit of emissions they produce. However, for mercury, the Clean Air Planning Act combines a minimum removal target for all plants with an emissions cap, and the Clean Power Act specifies a maximum emissions rate for all facilities and allows no trading of mercury allowances. The Clear Skies Act contains a "safety valve" feature that caps the price that power companies would have to pay for Hg ($2,187.50 per ounce or $35,000 per pound), SO_2 ($4,000 per ton), and NO_x ($4,000 per ton) allowances. Should one or more of these "safety valves" be triggered, the corresponding cap on emissions would effectively be relaxed.

Under the Clear Skies Act, emission allowances are to be allocated based on historical fuel consumption, what is often referred to as "grandfathering." Under the Clean Air Planning Act, a grandfathering approach is used to allocate emission allowances for SO_2, but allowances for NO_x, Hg, and CO_2, are allocated using an output-based scheme. Under this approach, referred to as a generation performance standard (GPS), generators are given allowances for each unit of electricity they generate. The number of allowances allocated for each unit of generation changes each year as the total generation from covered sources changes. The use of a GPS dampens the electricity price impacts of the bill but raises overall compliance costs.

In addition to the emission caps, the Clean Power Act also requires that all plants have the best available control technology (BACT) beginning in 2014 or when they reach 40 years of age, whichever comes later. This provision, often referred to as a "birthday" provision, requires older plants to add controls even if the total emissions of covered facilities are below the emission caps.

Methodology

This analysis was prepared using EIA's National Energy Modeling System (NEMS). The reference case used in this report is based on the reference case in the *Annual Energy Outlook 2004*[1], and it incorporates 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 or actions that might be taken to comply with the revised National Ambient Air Quality Standards for ozone and fine particulates. The implementation of such actions could affect emissions, generator costs, and electricity prices during the projection period even if there is no additional new legislation. In addition, the potential benefits that might be associated with emissions reductions are not discussed. EIA does not have expertise in the area of health benefits that might be associated with emissions reductions.

[1] Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA-0308(2004), (Washington, DC, January 2004), http://www.eia.doe.gov/oiaf/aeo/index.html.

The cases prepared in this analysis simulate the response of the economy to changing fuel prices and demands. However, recent information suggests that natural gas intensive industries may be more sensitive to higher natural gas prices than is reflected. Should this be true, the costs to the power sector of complying with the three bills could be lower since reduced industrial sector natural gas use would lower the pressure on natural gas markets, making it more economical for the electricity sector to use natural gas.

Throughout this report the generation and capacity data reported are for all generators, including small generators that are not covered by the emission limits. The emissions data shown are for the electric power sector, which includes all generators whose primary business is to produce and sell electricity.

Analysis of the Three Bills

Clear Skies Act (Inhofe): To comply with the provisions of this bill, power generators are expected to rely primarily on adding emissions control equipment to existing generators. Switching fuels from coal to natural gas and renewables is projected to play a relatively small role. Power generators are expected to reduce their mercury emissions prior to 2010 to take advantage of the early credit program. However, the use of early credits allows them to delay meeting the 2010 34-ton mercury emissions cap until 2013. In the longer term, because of the mercury safety valve, mercury emissions are projected to remain above the 15-ton emission target that takes effect in 2018 throughout the projections. SO_2 emissions are projected to approach the target, but because of allowance banking in the early phases, the 3-million-ton cap is not reached by 2025. The resource cost (the cost to the electric generation industry) and the electricity price impacts are the lowest among the three bills considered.

Clean Air Planning Act Bill (Carper): The addition of emissions control equipment to existing generators is also expected to play an important role in complying with this bill. However, because of the tighter emissions limits on SO_2, NO_x, and Hg and the addition of a CO_2 emissions cap, fuel switching from coal to natural gas and renewables is projected to be much more important than under the Clear Skies Act. The impacts are very sensitive to the availability and cost of greenhouse gas offsets. The Clean Air Planning Act calls for the establishment of an independent review board to evaluate potential greenhouse offsets, but the criteria they might use are uncertain. Because of this uncertainty two separate cases were prepared. One case, Carper Domestic, assumes that only domestic offset programs will be approved, while another, Carper International, assumes both domestic and international offsets will be available. These cases illustrate the sensitivity of the results to the cost and availability of greenhouse gas offsets, but may not span the full range of possible outcomes.

If greenhouse gas offsets are fairly inexpensive, they will be the primary option for meeting the CO_2 emissions limit. The more expensive are greenhouse offsets, the larger will be the role of switching fuels from coal to natural gas and renewables. The output-based allowance allocation scheme used in the Clean Air Planning Act does dampen the electricity price impacts, but it leads to higher resource costs. Overall, the resource cost and electricity price impacts of this bill are projected to be larger than those under the Clear Skies Act.

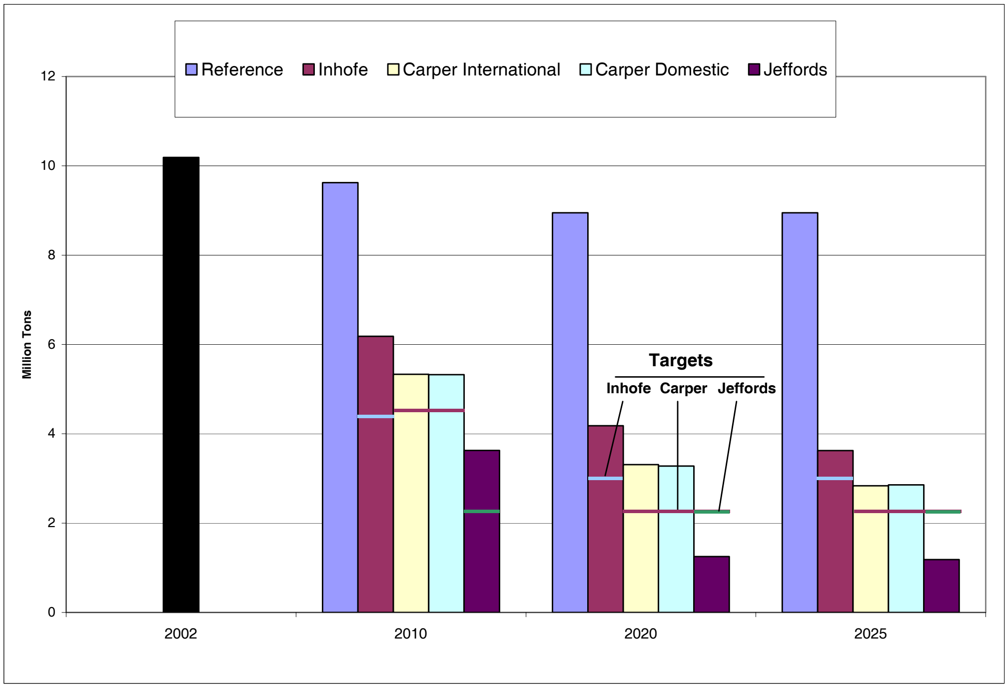
Clean Power Act (Jeffords): Under this bill the relatively stringent CO_2 emissions cap is projected to make switching from coal to natural gas, renewables, and nuclear especially important. The birthday provision causes many older plants to add emissions control equipment, even though the emissions of SO_2, NO_x, and Hg are projected to fall below their respective targets once power companies switch away from coal. A large number of new small generators and combined heat and power facilities are built because they are not covered by the bill's emissions caps. However, the bill reduces the emission caps for large generators to offset emissions from these sources. The early timing and stringency of the emissions limits combined with the birthday provision in this bill lead to the largest resource cost and electricity price impacts among the three bills. Because of the higher projected electricity prices, consumers are also expected to reduce their use of electricity.

The differences in the three bills can best be seen by comparing their respective impacts on emissions; coal, natural gas, renewable, and nuclear generation; electricity prices; and resource costs. For NO_x, power sector emissions in the Inhofe and Carper cases are projected to fall to the respective bill targets because the phase 1 and 2 emission targets are so close that there is little opportunity for economical allowance banking. Only in the Jeffords case, where the birthday provision requires all older plants to add emissions controls when they reach 40 years of age, are NO_x emissions projected to fall below the bill's emission target.

For SO_2, power sector emissions are projected to fall in all the cases, including the reference case (Figure ES1). However, in the Inhofe and Carper cases, SO_2 emissions are projected to remain above the bills' target levels because of allowances banked from the existing SO_2 reduction program. As with NO_x emissions, in the Jeffords case, SO_2 emissions are projected to fall below the bill's emission target.

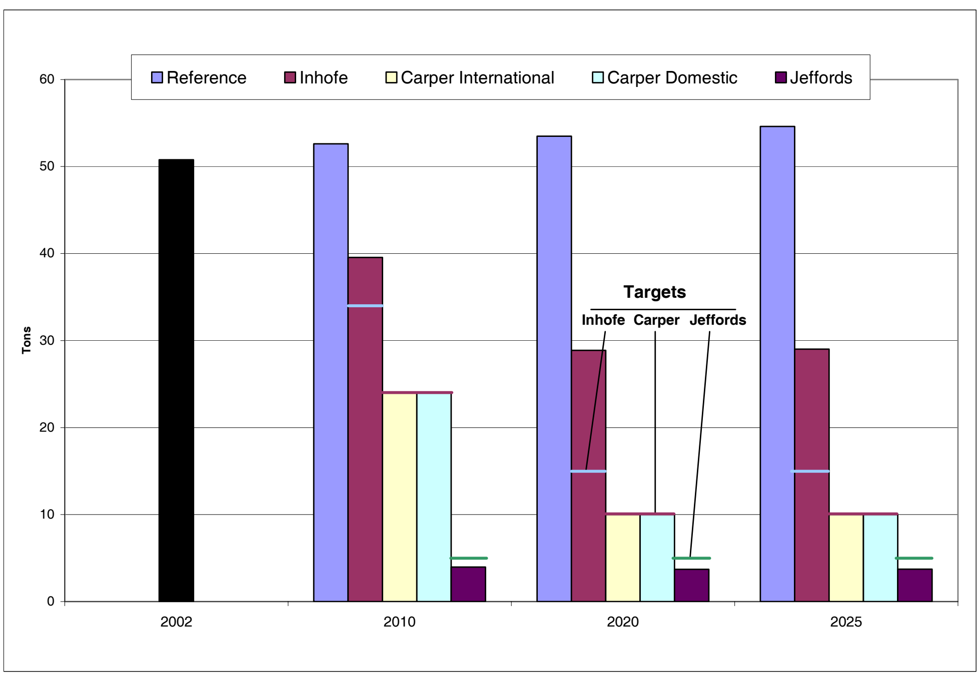
For Hg, power sector emissions are projected to remain above the 2018 target level in the Inhofe case throughout the projection period (Figure ES2). In the early years, this is due to power companies taking advantage of the early credit program to bank allowances prior to the beginning of the required reductions in 2010. The above-target-level emissions in the later years are caused by the mercury allowance price safety valve. In the Carper cases, without a mercury allowance price safety valve, power sector Hg emissions are expected to fall to the required target level. In the Jeffords case, similar to NO_x and SO_2, power sector Hg emissions are expected to fall below the bill's target level. This is caused by the combination of reduced coal use and the facility-specific mercury emission limit in the Jeffords bill.

Figure ES1. Electricity Sector SO_2 Emissions in Alternative Cases



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

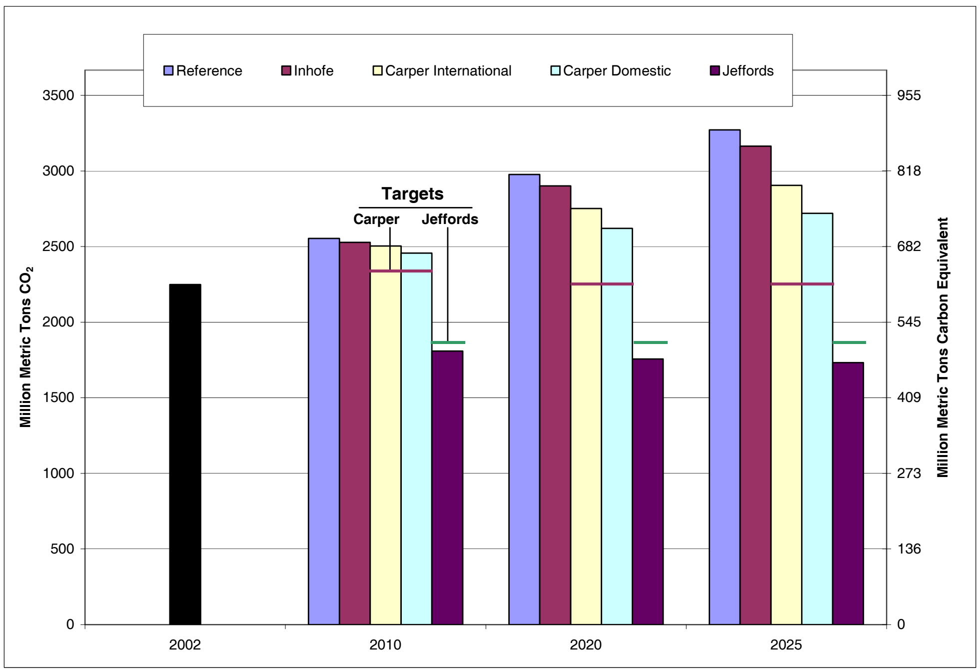
Figure ES2. Electricity Sector Mercury Emissions in Alternative Cases



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

For CO_2, power sector emissions are projected to increase over time in all the cases, except the Jeffords case (Figure ES3). In the Carper cases, power companies are expected to rely heavily on greenhouse gas offsets outside the covered sector to meet the CO_2 emissions target. The purchase of greenhouse gas offsets accounts for between 46 percent and 64 percent of the overall CO_2 emission reductions required in the two Carper cases in 2025. In the Jeffords case, power sector CO_2 emissions are projected to gradually fall below the level because the covered generators' emissions limit is adjusted for the growing emissions from small generators in the industrial and commercial sectors who sell power to the grid.

Figure ES3. Electricity Sector Carbon Dioxide Emissions in Alternative Cases

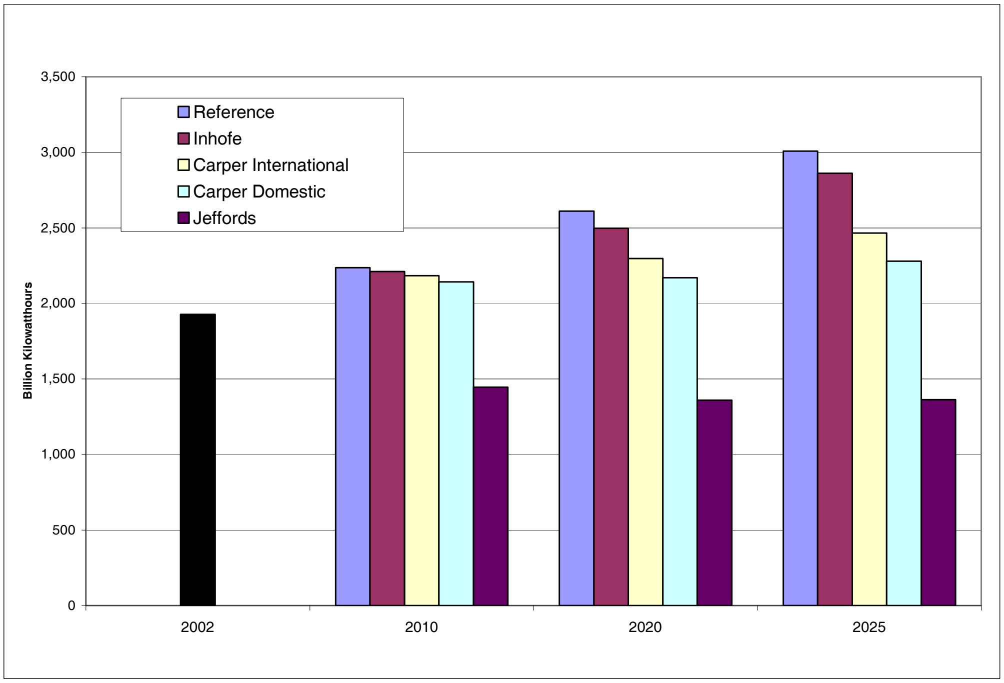


Note: The CO_2 target in the Jeffords bill is adjusted downward to cover the emissions from the new small generation and combined heat and power facilities.
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

All three bills are projected to lead to lower coal generation than in the reference case (Figure ES4). The change in the Inhofe case is relatively modest, 5 percent below the reference case in 2025. In the two Carper cases, the impact on coal generation is larger, falling as much as 24 percent below the reference case level in 2025. The reduction in coal generation is projected to be most pronounced in the Jeffords case where it is 55 percent below the reference case in 2025.

In contrast to coal generation, natural gas and renewable generation are projected to be higher under the three bills (Figures ES5 and ES6). Again, in the Inhofe case, the impact on natural gas and renewable generation is projected to be modest. In the long run, the shift to natural gas is projected to be largest in the Carper cases, due to the less stringent

Figure ES4. Coal Generation in Alternative Cases



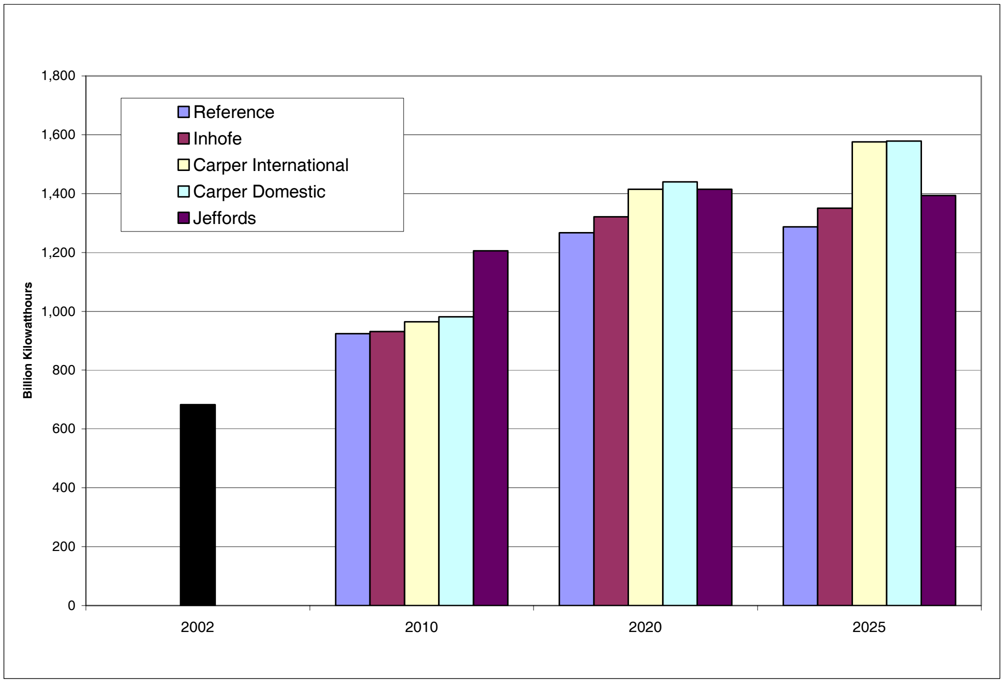
Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

CO_2 emissions cap and the availability of greenhouse gas offsets. In the Jeffords case, the relatively stringent CO_2 emissions cap is expected to result in large increases in the use of non-fossil fuels, especially in the longer term. In the near term, before non-fossil technologies such as advanced nuclear and biomass plants are projected to be available, power generators are projected to turn to natural gas to comply.

The Jeffords case is the only case where new nuclear plants are projected. With CO_2 allowance prices of at least $29 per metric ton ($108 per metric ton carbon equivalent) throughout the projection period, new nuclear plants are projected to be economical in the Jeffords case once they become available. However, because the first new nuclear plant is expected to take 10 years to plan, permit, and construct, their impact is not expected to be large until the later years of the projections. By 2025, nuclear generation is projected to be 53 percent above the reference case level in the Jeffords case.

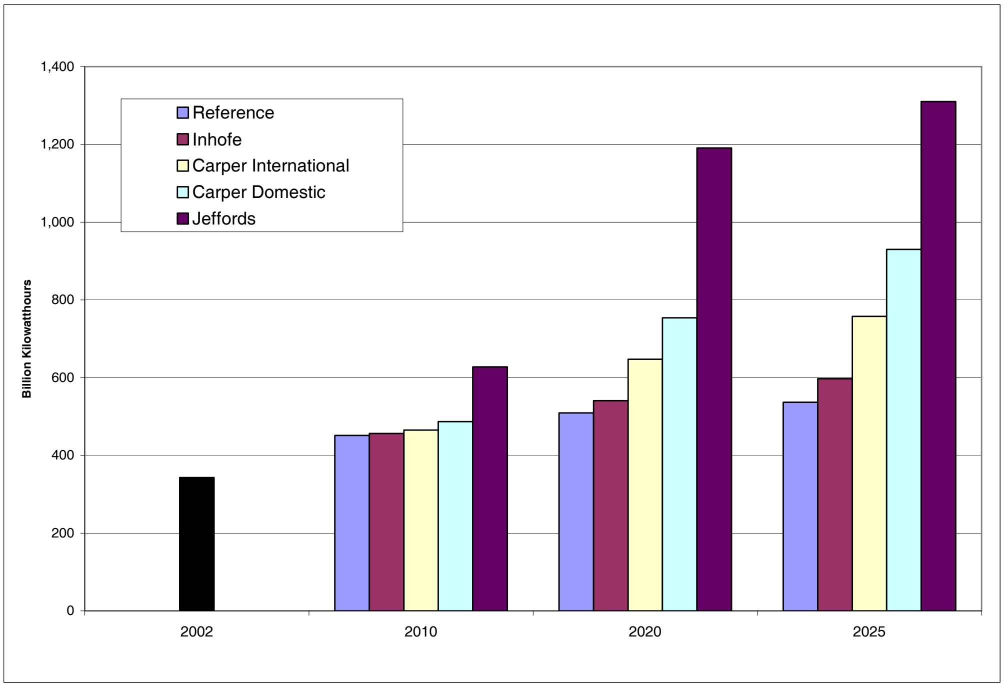
Relative to the reference case, electricity prices in the Inhofe case are projected to be 3.2 percent higher in 2025 (Figure ES7). In the Carper cases, electricity prices are expected to be as much as 7.8 percent higher in 2025. The electricity price impacts are expected to be much larger in the Jeffords case, 47 and 27 percent above the reference case levels in 2010 and 2025, respectively. The high near-term impact results from the need to rapidly transform the industry from using coal to natural gas, renewables, and nuclear.

Figure ES5. Natural Gas Generation in Alternative Cases



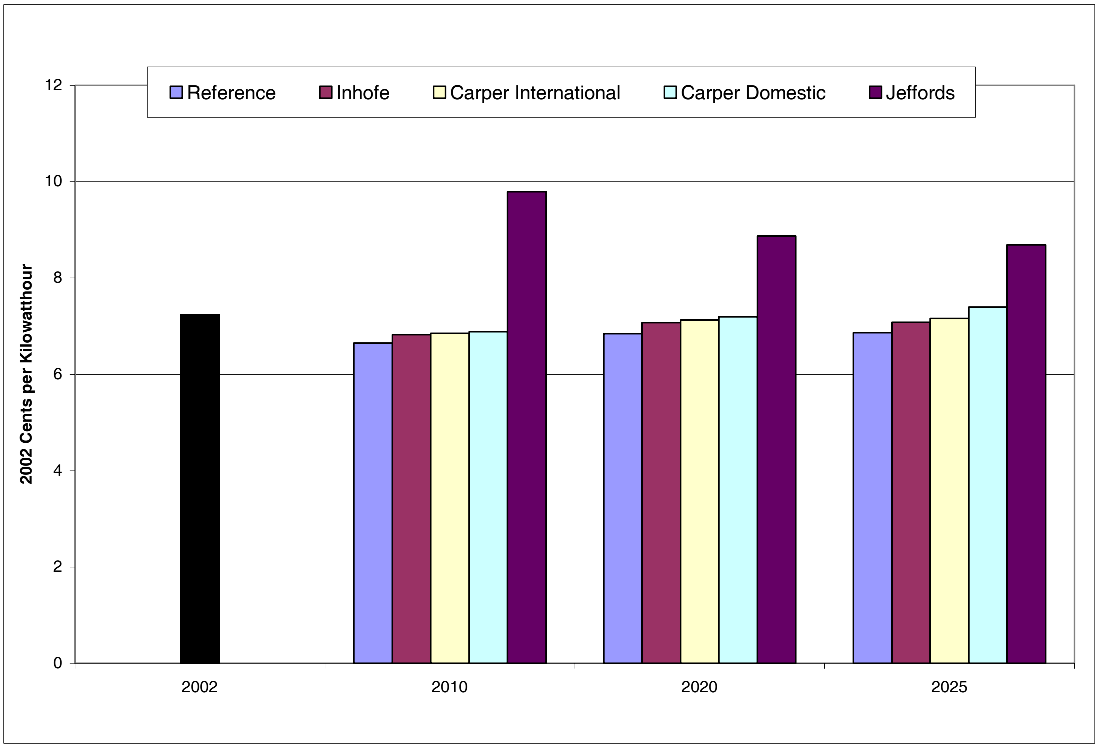
Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure ES6. Renewable Generation in Alternative Cases



Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure ES7. Electricity Prices in Alternative Cases



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The projected change in power sector resource costs, the amount that power companies spend on fuel, capital, and operations and maintenance, tend to follow a pattern similar to that for electricity prices. Over the 2005 to 2025 time period, discounted resource costs are projected to be 1.3 percent higher in the Inhofe case. For the Carper cases, they are projected to be between 2.9 percent and 4.5 percent higher, while in the Jeffords case they are 19.5 percent higher.

Uncertainties

As with any long-term projection, there are considerable uncertainties. It is impossible to predict future fuel prices and 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 future natural gas prices, the availability and market acceptance of low- or zero-carbon generation technologies, including new nuclear, renewable, and fossil plants with carbon capture and sequestration equipment, the availability and cost of greenhouse gas offsets, and the cost and performance of emerging mercury removal technologies.

One only has to look at the behavior of natural gas prices over the past several years to observe the volatility and uncertainty in the market. Current prices are much higher than they were just a few years ago and, if they remain high, the costs of shifting from coal to natural gas in response to the three bills could be more expensive, particularly in the Carper and Jeffords cases where fuel switching is expected to be a more important compliance option. With higher natural gas prices, other low-carbon generating technologies such as new renewables and nuclear would likely play an increased role. On the other hand, if industrial natural gas users reduce their consumption more aggressively in response to higher natural gas prices, the compliance costs on the power sector could be smaller than estimated.

The potential availability and cost of greenhouse gas offsets is an important area of uncertainty when analyzing the impacts of the Carper bill. 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. Relatively lenient rules could make offsets less costly, but they could also make it difficult to ensure that emissions reductions or increases in sequestration are occurring.

With regard to mercury control, there have been few full-scale demonstrations of some of the plant configurations that are necessary to meet the requirements of the proposed bills. This is particularly true for the lower-rank coals, subbituminous and lignite. While technologies that remove SO_2 and NO_x have shown great promise in removing mercury from bituminous coals, they have not performed as well with the lower-ranked coals. Supplemental fabric filter systems using activated carbon injection are expected to be a key technology in removing mercury. However, tests of such systems on plants using subbituminous or lignite coals are only now being evaluated.

A key result of the Carper and Jeffords cases is that the power sector is going to increasingly rely on technologies such as wind and biomass, that currently play a relatively small role in the U.S. generation market, or technologies like nuclear that have not been expanded in many years to comply with the CO_2 emission caps. Such a transformation would clearly be challenging, especially in the timeframe called for in the Jeffords case.

1. Background and Summary of the Bills

On March 19, 2004, Senator James M. Inhofe requested the Energy Information Administration (EIA) to undertake analysis of S.843, the Clean Air Planning Act of 2003, introduced by Senator Thomas Carper; S.366, the Clean Power Act of 2003, introduced by Senator James Jeffords; and S.1844, the Clear Skies Act of 2003, introduced by Senator James M. Inhofe. This Service Report responds to his request.

Bill Summary

These 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, the Clean Air Planning Act and the Clean Power Act also call for reductions in power sector emissions of carbon dioxide (CO_2). The emissions caps and reduction timetables differ, but the bills generally call for cap-and-trade emission reduction programs (Table 1 and Figures 1 through 4) covering most electricity-generating facilities.

Table 1. Emission Targets in S.366, S. 843, and S. 1844

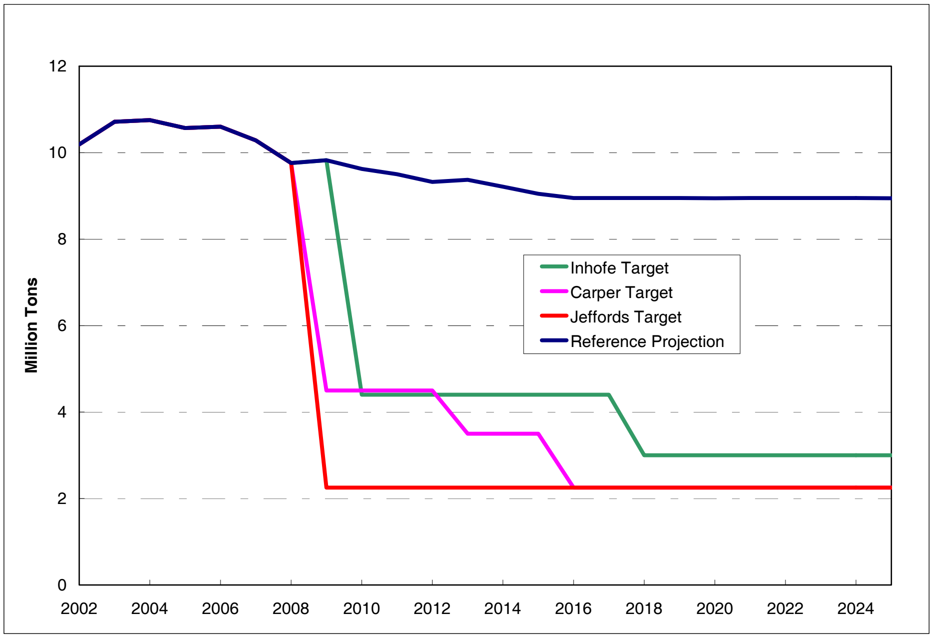
Emission	S. 366, Clean Power Act (Jeffords)	S. 843, Clean Air Planning Act (Carper)	S. 1844, Clear Skies Act (Inhofe)
Nitrogen Oxides (NO_x)	1.51 million tons in 2009	1.87 million tons in 2009 1.7 million tons in 2013	2.19 million tons in 2008 1.79 million tons in 2018[a]
Sulfur Dioxide (SO_2)	2.25 million tons in 2009[b]	4.5 million tons in 2009 3.5 million tons in 2013 2.25 million tons in 2016	4.4 million tons in 2010 3.0 million tons in 2018
Mercury (Hg)	5 tons in 2008[c]	24 tons in 2009 10 tons in 2013[d]	34 tons in 2010 15 tons in 2018
Carbon Dioxide (CO_2)	1,863 million metric tons CO_2 (508 million metric tons carbon equivalent) in 2009[e]	2,332 million metric tons CO_2 (636 million metric tons carbon equivalent) in 2009 2,244 million metric tons CO_2 (612 million metric tons carbon equivalent) in 2013[f]	No cap

a. Limit on NO_x emissions is split between 2 regions: 1.47 million tons in Zone 1 (the East) in 2008 to 2017, and 0.72 million tons in Zone 2 (the West) in 2008 to 2017; 1.07 million tons in Zone 1 (the East) in 2018, and 0.72 million tons in Zone 2 (the West) in 2018.
b. Limit on SO_2 emissions is split between 2 regions, 0.275 million tons in the West and 1.975 million tons for the non-Western region.
c. Minimum facility-specific reductions without trading are required.
d. Minimum facility-specific reductions of between 50 percent (2009 to 2012) and 70 percent (after 2012) are required.
e. This is the 1990 level of CO_2 emissions from the electricity sector.
f. 2009 to 2012 limits are based on EIA projected emissions for 2006 from the most recent Annual Energy Outlook. The limit for 2013 and subsequent years is based on actual 2001 emissions.

Source: S. 366: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s366is.txt.pdf,
S. 843: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf,
S. 1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s1844is.txt.pdf.

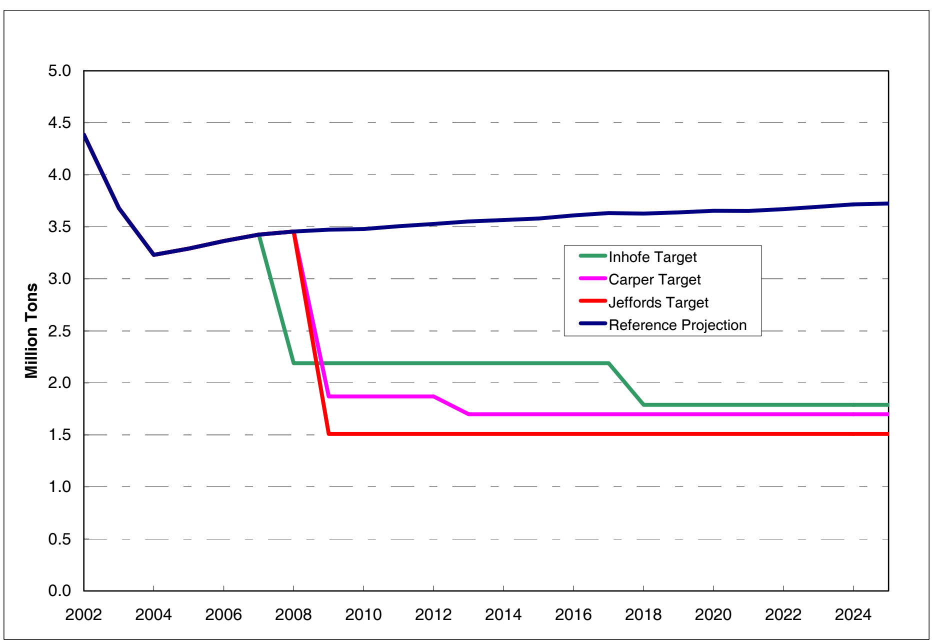
[2] For pdf versions of the bills, see S.366: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s366is.txt.pdf, S.843: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf, S.1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bill&docid=f:s1844is.txt.pdf.

Figure 1. Sulfur Dioxide Emission Projections and Targets



Sources: Reference projection: National Energy Modeling System run, inbase.d040904a.
Proposed bills: S. 366: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s366is.txt.pdf,
S. 843: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf,
S. 1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s1844is.txt.pdf.

Figure 2. Nitrogen Oxide Emission Projections and Targets



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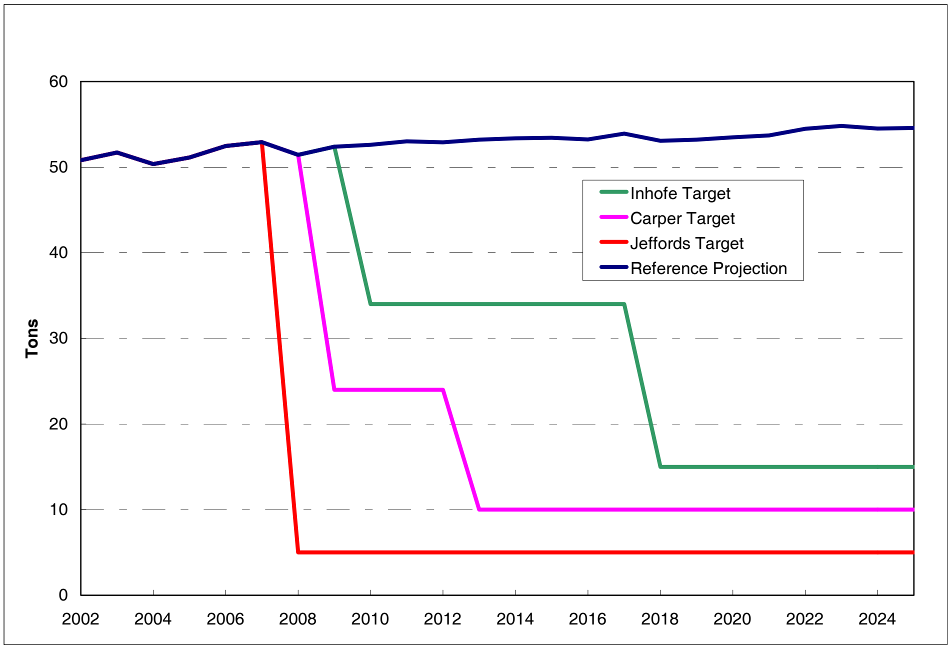
S. 1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s1844is.txt.pdf.

Figure 3. Mercury Emission Projections and Targets



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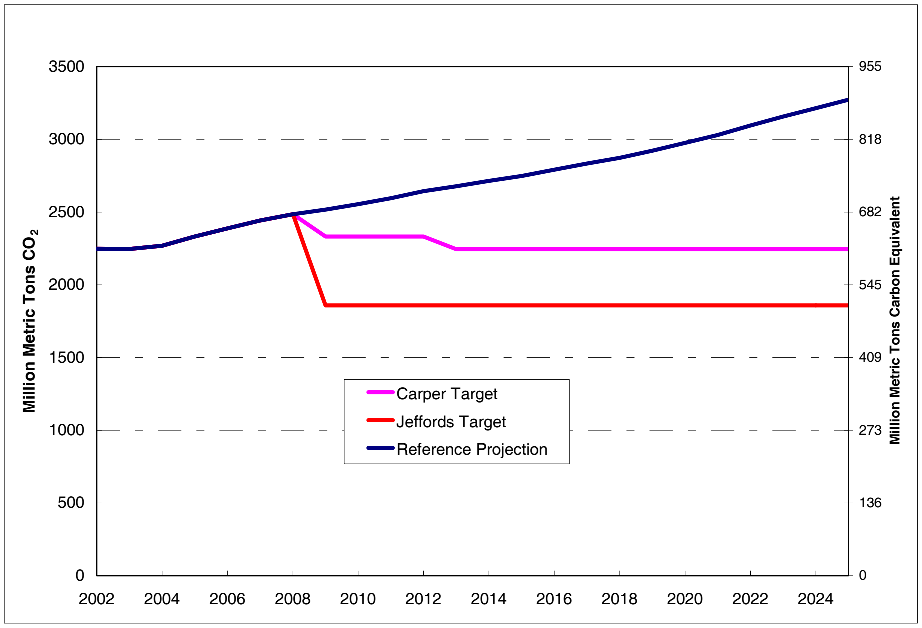
S. 366: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s366is.txt.pdf,
S. 843: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf,
S. 1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s1844is.txt.pdf.

Figure 4. Carbon Dioxide Emission Projections and Targets



Sources: Reference projection: National Energy Modeling System run, inbase.d040904a. Proposed bills:
S. 366: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s366is.txt.pdf,
S. 843: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf,
S. 1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s1844is.txt.pdf.

All three bills cover emissions from larger generators that generate power for sale. This includes central station generators and generators at customer sites that sell power they do not use for their own needs. The exact provisions in each of the acts do differ in some respects. The Clear Skies and Clean Air Planning Acts cover generating facilities 25 megawatts and larger, while the Clean Power Act covers facilities 15 megawatts and larger. The Clear Skies and Clean Air Planning Acts do not cover combined heat and power facilities (often referred to as cogeneration facilities) unless they meet the size requirement and they provide more than one-third of their potential output to any utility power distribution company for sale. The Clean Power Act covers combined heat and power facilities as long as they meet the size requirement and produce any power for sale. In all three acts, facilities that do not generate any power for sale are not covered.

Neither the Clear Skies nor the Clean Air Planning Act places any requirements on the emissions of facilities that are not directly covered by their emission targets. However, while the Clean Power Act does not explicitly cover generating facilities smaller than 15 megawatts that sell power, it does require that the cap on the emissions from larger facilities be adjusted to account for their emissions. Specifically, beginning in 2009, the emissions caps on larger facilities must be reduced by the emissions from smaller facilities from the second preceding year. In other words, the 2009 emissions caps for covered larger facilities are reduced by the 2007 emissions from smaller facilities. In this analysis, the CO_2 emissions caps in the Clean Power Act are adjusted to account for estimated emissions by small generators in the end-use sectors that sell power to the grid. The emissions from small generators in the power sector are directly included in the emissions cap, but these generators are not required to pay for CO_2 allowances.

To put the emission targets in perspective, the Clear Skies Act calls for reducing SO_2 emissions by 72 percent from the 2001 emission level, while the Clean Air Planning and Clean Power Acts call for a 79-percent reduction. For NO_x, Clear Skies calls for a 62-percent reduction from the 2001 emission level while the Clean Air Planning Act calls for a 64-percent reduction and the Clean Power Act calls for a 68-percent reduction. For Hg, Clear Skies calls for a 69-percent reduction from the 2001 level while the Clean Air Planning Act calls for an 80-percent reduction, and the Clean Power Act calls for a 90-percent reduction.[3] The emission targets in the bill may not be achieved by the target dates because of allowance banking and, in the case of the Clear Skies Act, the safety valve limitations on allowance prices.

The Clean Air Planning Act calls for reducing CO_2 emissions from electricity generating plants in 2009 to the level projected in EIA's reference case for 2005[4] 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 Clean Air Planning Act would require a 25-percent reduction in 2020 and a 32-percent reduction in 2025[5]. However, the Clean Air Planning Act allows generators to comply

[3] Calculations based on aeo2004.d101703e, Table 117, electricity sector emissions of NO_x in 2001 equal to 4.75 million tons, electricity sector emissions of SO_2 in 2001 equal to 10.63 million tons, and electricity sector emissions of mercury in 2001 equal to 49.14 tons.
[4] Based on reference case run aeo2004.d101703e.
[5] Based on reference case run aeo2004.d101703e, CO_2 emissions for 2020 equal 2,989 million metric tonnes of carbon dioxide equivalent or 815 (2,989 x 12/44) million metric tonnes of carbon equivalent and CO_2 emissions for 2025 equal 3,299 million metric tonnes of carbon dioxide equivalent or 900 (3,299 x 12/44) million metric tonnes of carbon equivalent.

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. The Clean Power Act calls for reducing CO_2 emissions from electricity generating plants in 2009 to 1990 levels, approximately 39 percent below the projected level in 2020 and 43 percent below the projected level in 2025. There are no carbon emission reductions under the Clear Skies Act.

All of the bills rely primarily on emissions cap-and-trade programs to meet their specified emission targets (except for mercury under the Clean Power Act). Under a cap-and-trade program, each power plant must annually submit an allowance for each unit (i.e., tons, metric tons, pounds, or ounces) of emissions. 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 over-comply 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 important features in each bill. These include:

Excess emissions penalties and allowance price safety valves

The Clear Skies Act sets excess emissions penalty for NO_x at \$2,000 per ton. For SO_2, the penalty before 2008 is \$2,000 per ton of SO_2 if offsets are made and payments are received within 30 days. If offsets are not made or payments are not received within 30 days, then the penalty is \$4,000 per ton of SO_2. After 2007, the penalty for SO_2 is set to the annual average price of SO_2 allowances. These penalty values, originally established in 1990 dollars in the Clean Air Act Amendments of 1990, are adjusted for inflation. For mercury, the penalty is set to the annual average price of mercury allowances. Facilities with excess emissions are required to pay the penalties and reduce their future emissions to cover their excess emissions. That is, facility owners cannot just pay the penalty and not reduce their emissions.

In addition, the Clear Skies Act establishes an allowance price safety valve for each type of 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 puts a limit on the respective allowance prices and, if utilized, will cause the emission targets to be exceeded.[6] Under Clear Skies the safety valve values are: \$2,000 per ton for SO_2, \$4,000 per ton for NO_x, and \$2,187.50 per ounce (\$35,000 per pound) for mercury. These values are to be adjusted for inflation beginning with the year the act is passed.

The Clean Air Planning Act does not specify safety valves, but imposes excess emissions penalties amounting to: \$2,000 (in year 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

[6] 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."

year or within a period of time prescribed by the Administrator of the Environmental Protection Agency (EPA).

The Clean Power Act does not specify safety valves, but imposes excess emissions penalties for SO_2, NO_x, and CO_2, amounting to three times the excess emissions in tons multiplied by the average annual market price for the appropriate allowances. For mercury, the excess emissions penalty amounts to three times the excess emissions in grams multiplied by the average cost of mercury controls.

Facility-specific mercury limits

The Clean Air Planning Act 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 used as fuel or that each facility meet an output-based rate to be set by the EPA Administrator. 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. This will lead to lower allowance prices but higher industry cost than would occur with only a cap-and-trade program.

The Clean Power Act sets a facility specific mercury emissions limit of 2.48 grams per 1,000 megawatthours. This is an emissions limit, not an allocation of allowances, and it may not be banked or traded.

"Birthday Provisions"

Both the Clean Air Planning and Clean Power Acts include provisions triggered when plants reach a specified age, referred to as "birthday provisions." Beginning in 2020, the Clean Air Planning Act 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.

The Clean Power Act requires that all plants have the best available control technology (BACT) beginning in 2014 or when they reach 40 years of age, whichever comes later.

Allowance programs

The Clear Skies Act 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. The baseline period for calculating heat input is the highest 3 years of fuel use for each facility between 1998 and 2002.

For SO_2, the Clean Air Planning Act also allocates allowances using a grandfathering approach, while for NO_x, mercury, 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 3 years of each facility's generation. Essentially this is a rolling 3-year generation performance standard (GPS) for NO_x, mercury, and CO_2. Under this bill, allowances are also allocated to new units until they have operated for 3 years and become part of the regular GPS program.[7]

The GPS programs in the Clean Air Planning Act will impact the cost and price impacts of meeting the emission targets. In general, a dynamic GPS, which is updated continuously as 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.[8] 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."[9] 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 Clean Air Planning Act 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 own

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[7] 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.
[8] 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.
[9] C. Fischer, *Rebating Environmental Policy Revenues: Output-based Allocations and Tradable Performance Standards* (Washington, DC: Resources for the Future, January 21, 1999).

emissions. In addition to existing fossil generators, new fossil fuel and renewable units receive CO_2 allowances.[10]

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.[11]

Under the Clean Power Act, most allowances are to be allocated to households served by electricity. Other entities receiving allowances include dislocated workers, makers of electricity intensive products, and investors in renewable energy, energy efficiency, cleaner energy, and biological sequestration. In addition, owners or operators of electricity generators receive a declining share of the allowances allocated. The share starts at 10 percent in 2009 and falls to 1 percent in 2018. For this analysis, it is assumed that consumers receive a lump sum payment equal to the allowance revenue each year.

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[10] The emissions cap in the Clean Air Planning Act 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.

[11] 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), http://www.eia.doe.gov/oiaf/servicerpt/ml/pdf/sroiaf(2003)02.pdf.

2. Analysis of the Proposed Bills

The proposed bills were analyzed using the EIA's National Energy Modeling System (NEMS). The reference case for the analysis was based on EIA's *Annual Energy Outlook 2004 (AEO2004)* and it incorporates final regulatory action under existing laws.[12] Minor updates have been made to the reference case since the *AEO2004* was prepared.[13] It should be noted that the projections in the cases in this report are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The reference case projections are business-as-usual trend forecasts, given known technology, technological and demographic trends, and current laws and regulations. EIA does not propose, advocate, or speculate on future legislative and regulatory changes. All laws are assumed to remain as currently enacted; however, the impacts of planned regulatory changes, when defined, are reflected. Consistent with standard EIA practice requiring policy neutrality in baseline projections, it does not include pending or proposed actions, such as the maximum achievable control technology (MACT) standards for mercury emissions from power plants or actions that might be taken to comply with the revised National Ambient Air Quality Standards for ozone and fine particulates. The implementation of such actions could affect emissions, generator costs, and electricity prices during the projection period even if there is no new legislation. In addition, the potential benefits that might be associated with emissions reductions are not discussed. EIA does not have expertise in the area of health benefits that might be associated with emissions reductions.

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.

Analysis Cases

Table 2 describes the cases prepared for this analysis. Two cases were prepared to analyze the impacts of the Clean Air Planning Act because of uncertainty about the cost and availability of greenhouse gas offsets. The Clean Air Planning Act calls for the establishment of an independent review board to evaluate potential greenhouse offsets, but the criteria they might use are uncertain. One case, Carper Domestic, assumes that only domestic offset programs will be approved, while another, Carper International, assumes both domestic and international offsets will be available. These cases should not be seen as spanning the full range of possible outcomes, but rather representing a reasonable range of outcomes and illustrating the sensitivity of the results to the cost and availability of greenhouse gas offsets.

[12] Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA-0308(2004), (Washington, DC, January 2004), http://www.eia.doe.gov/oiaf/aeo/index.html.
[13] The key updates are the calibration of natural gas prices and consumption to the latest available information. Other minor updates were also incorporated.

Table 2. Analysis Cases for Three Proposed Bills

Case Mnemonic	Long Name	Description
Reference	Reference	Reference case based on the *Annual Energy Outlook 2004* with minor updates.
Inhofe	Clear Skies	Reference case plus provisions of S. 1844 introduced by Senator Inhofe.
Carper International	Clean Air Planning Act – Domestic and International Offsets	Reference case plus provisions of S. 843 introduced by Senator Carper. Both domestic and international greenhouse gas offsets are permitted.
Carper Domestic	Clean Air Planning Act – Domestic Offsets Only	Reference case plus provisions of S. 843 introduced by Senator Carper. Only domestic greenhouse gas offsets are permitted.
Jeffords	Clean Power Act	Reference case plus provisions of S. 366 introduced by Senator Jeffords.

Sources: Proposed bills:
S. 366: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s366is.txt.pdf,
S. 843: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s843is.txt.pdf,
S. 1844: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=108_cong_bills&docid=f:s1844is.txt.pdf.

The cases prepared in this analysis simulate the response of the economy to changing fuel prices and demands. However, recent information suggests that natural gas intensive industries may be more sensitive to higher natural gas prices than is reflected. If these industries are truly more sensitive to natural gas prices, the costs to the power sector of complying with the three bills could be lower. Reduced industrial sector natural gas use would lower the pressure on natural gas markets, making it more economical for the electricity sector to use natural gas. However, this would lead to greater economic loss in the industrial sector.

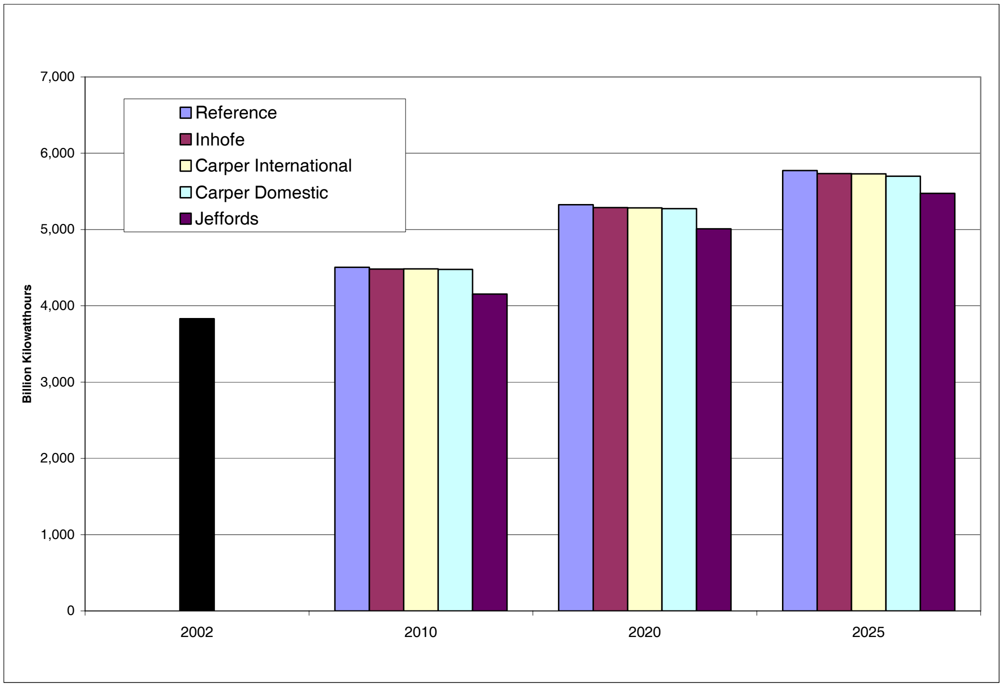
Throughout this analysis, in order to show the full impacts of the acts, the generation and capacity data reported are for all generators, including small generators that are not covered by the emission limits. As described on page 1, the coverage of the acts does differ in some respects. The emissions data shown are for the electric power sector, which includes all generators whose primary business is to produce and sell electricity.

Generation and Fuel Use

Because of consumers' responses to higher electricity prices, all of the bills are projected to have lower overall generation than in the reference case (Figure 5). In the Inhofe and Carper cases the change in total generation is expected to be relatively small, with the largest difference being 1 percent lower in the Carper Domestic case. However, in the Jeffords case, total electricity generation is projected to be 7.8 percent below the reference case level in 2010 and 5.2 percent below it in 2025.

All of the bills are projected to lead to lower coal generation and increased generation from natural gas, renewables, and, in the case of Jeffords, nuclear. However, the provisions of the Inhofe bill (S. 1844) are expected to lead to a relatively small shift in the fuels used to generate electricity compared to the other bills. In contrast, the provisions of the Carper and Jeffords bills are expected to lead to larger changes.

Figure 5. Total Generation in Alternative Cases

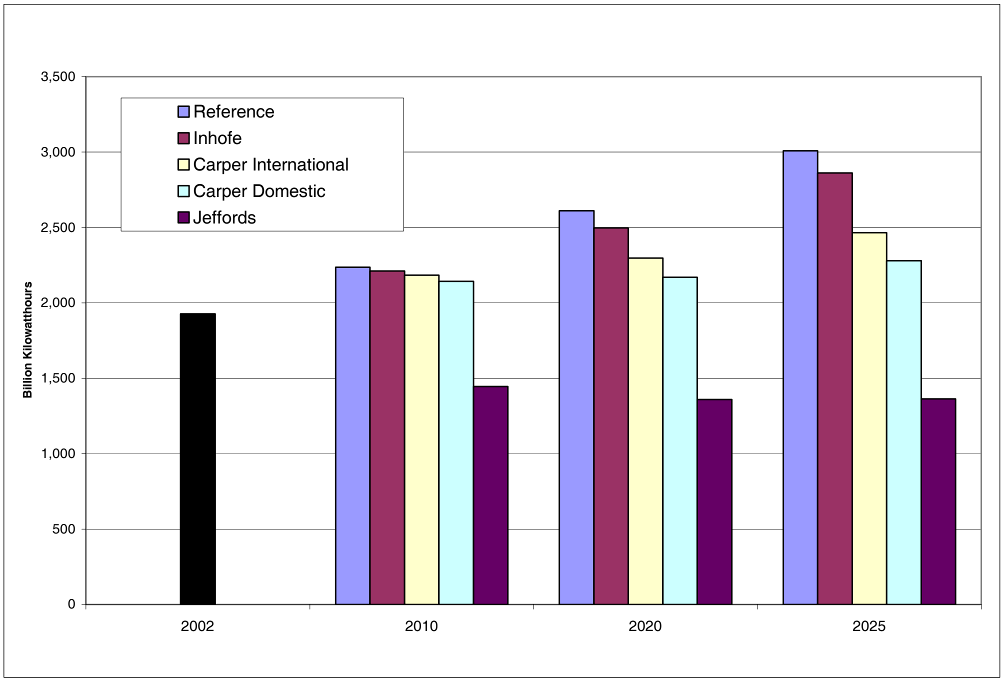


Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Relative to the reference case, coal generation is expected to be 1.1 and 4.9 percent lower in 2010 and 2025, respectively, in the Inhofe case (Figure 6).   Conversely, natural gas generation is projected to be 0.8 and 4.9 percent higher in 2010 and 2025, respectively. Over the entire 2002 through 2025 time period natural gas use in the power sector is projected be 1.8 percent higher with the Inhofe bill than without it. For renewables, generation is projected to be 1.1 and 11.2 percent higher in 2010 and 2025, respectively, in the Inhofe case.

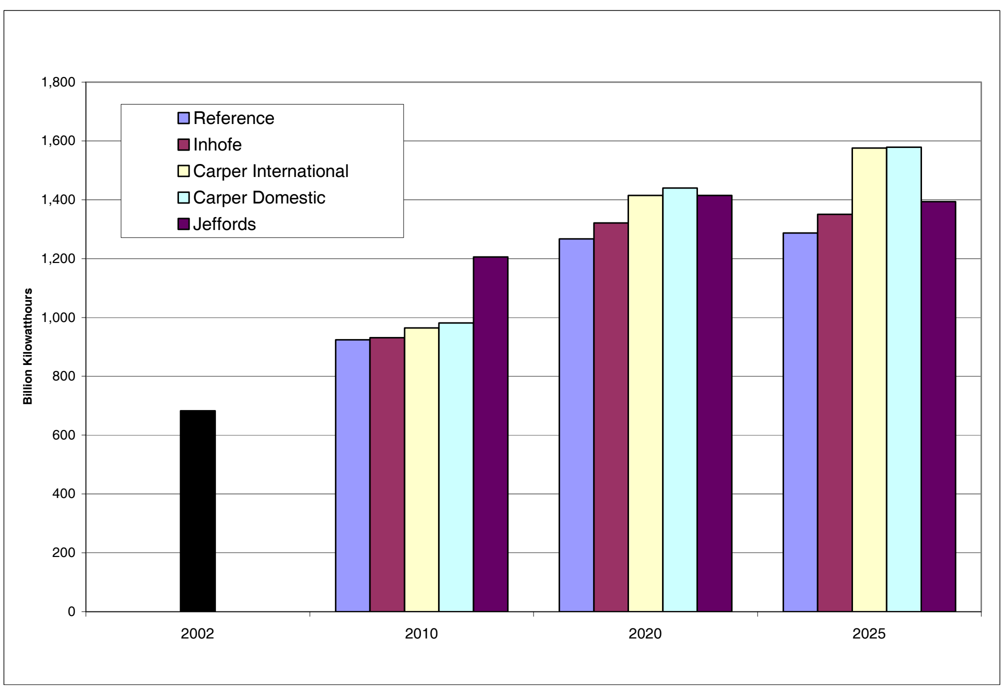
Primarily because of their CO_2 emission cap levels, the shifts away from coal towards natural gas and renewables are projected to be much larger under the Carper and Jeffords bills than under the Inhofe bill. In the Carper cases, coal generation in 2020 is projected to be between 12.0 and 16.9 percent below the reference case level. By 2025, this reduction is expected to grow to between 18.0 and 24.2 percent. The range of impacts seen in the Carper cases is driven by assumptions about the availability and cost of greenhouse offsets outside of the power sector. When greenhouse offsets are relatively inexpensive, as in the Carper International case, coal use is not as severely impacted. In contrast to coal, natural gas generation is projected to be from 4.4 to 6.3 and 22.4 to 22.7 percent higher in 2010 and 2025, respectively, in the Carper cases (Figure 7). Similarly, renewable generation is projected to be from 3.0 to 7.9 and 41.1 to 73.2 percent higher in 2010 and 2025, respectively, in the Carper cases (Figure 8). The role of renewables

Figure 6. Coal Generation in Alternative Cases



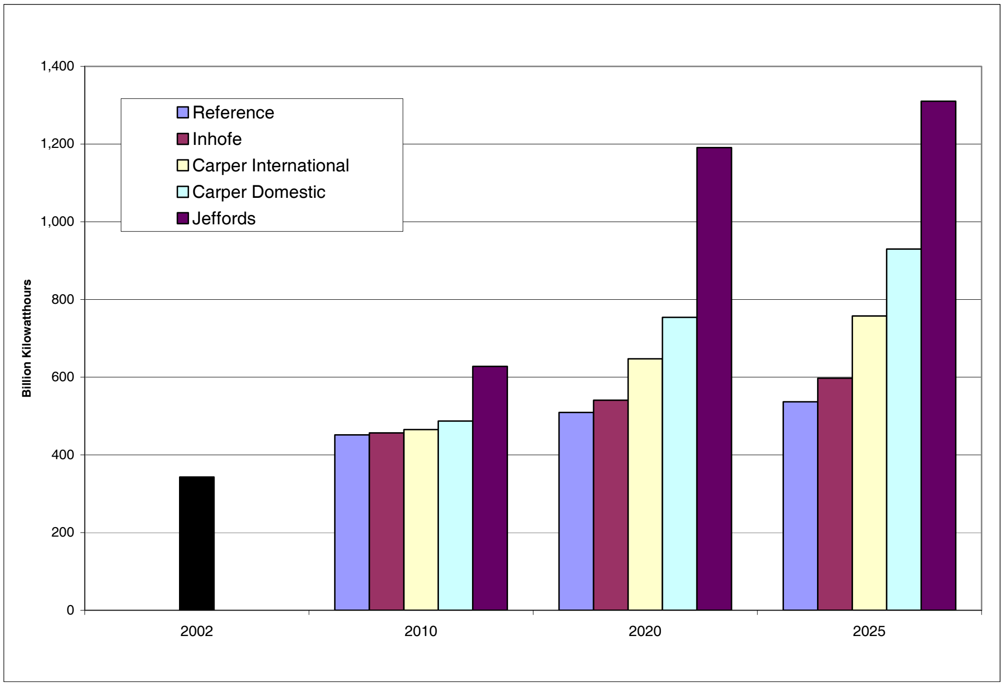
Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 7. Natural Gas Generation in Alternative Cases



Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 8. Renewable Generation in Alternative Cases

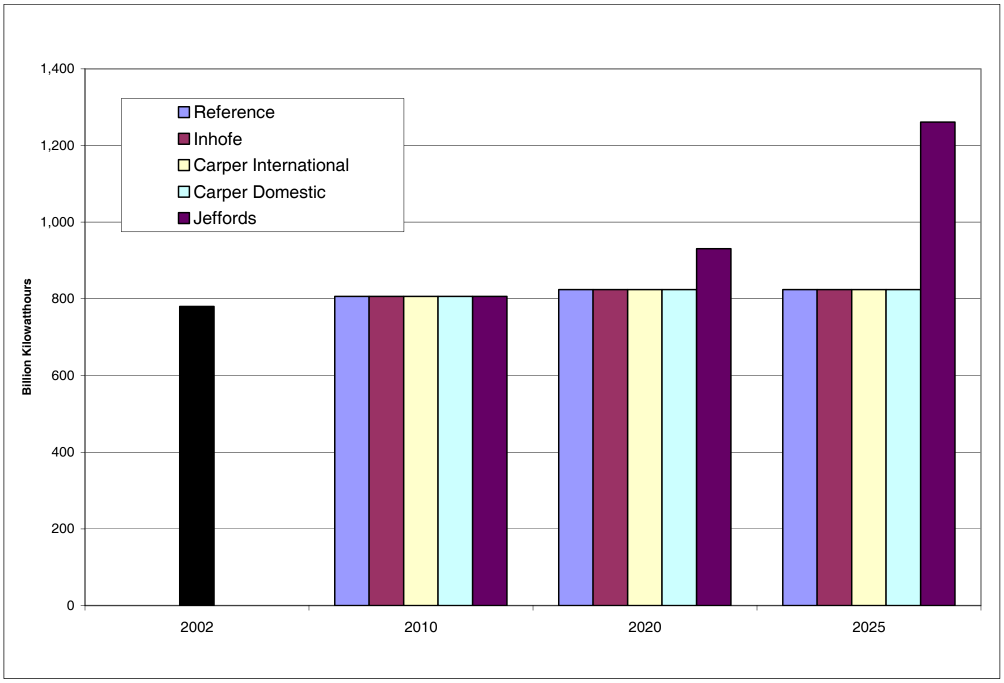


Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

becomes increasingly important as carbon allowance prices grow. At high enough carbon allowance prices, such as in the Jeffords bill, even natural gas-fueled plants which have lower carbon emissions than coal plants, begin to become economically unattractive.

The shift from coal to natural gas, renewables, and nuclear, is most pronounced in the Jeffords case. The relatively stringent emission caps, particularly the CO_2 cap, cause a large decline in coal generation. Relative to the reference case, coal generation is expected to be 35.3 and 54.7 percent lower in 2010 and 2025, respectively, in the Jeffords case. Conversely, natural gas generation is projected to be 30.5 and 8.3 percent higher in 2010 and 2025, respectively, compared to the reference case. The relatively high CO_2 allowance price in the Jeffords case causes growth in natural gas generation to slow as the electric power industry turns to renewables and new nuclear plants in the later years of the projections. Because of their long permitting and construction lead times, new nuclear plants are not expected to be able to begin contributing to reducing CO_2 emissions until 2014. Renewable generation in the Jeffords case is projected to be 133.9 and 144.1 percent higher in 2020 and 2025, respectively, than in the reference case. In the same years nuclear generation is projected to be 13.0 and 53.1 percent higher than in the reference case (Figure 9).

Figure 9. Nuclear Generation in Alternative Cases

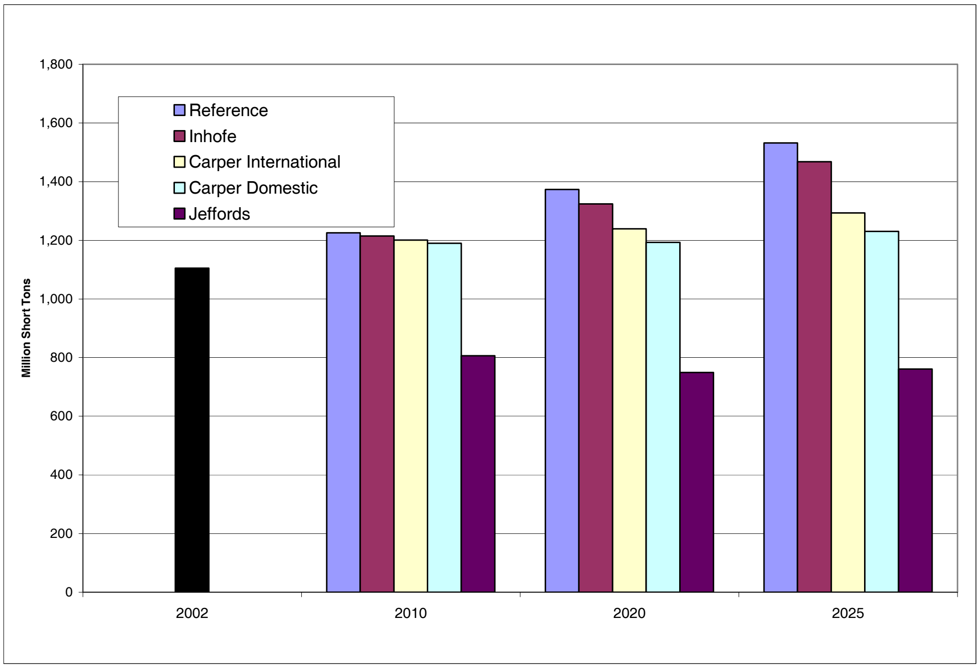


Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The change in coal production follows the decline in coal generation across the cases (Figure 10). In the Inhofe case, coal production is 10.9 and 64.9 million tons (0.9 and 4.2 percent) below the reference case level in 2010 and 2025, respectively. In the Carper cases, the reduction in coal production is much larger, ranging from 133.7 to180.5 million tons (9.7 to 13.1 percent) lower than the reference case level in 2020, and 238.4 to 302.2 million tons (15.6 to 19.7 percent) lower than the reference case level in 2025. The reduction in coal is even larger in the Jeffords case. Relative to the reference case, it is 623.4 million tons (45.4 percent) lower in 2020 and 771.6 million tons (50.4 percent) lower in 2025.

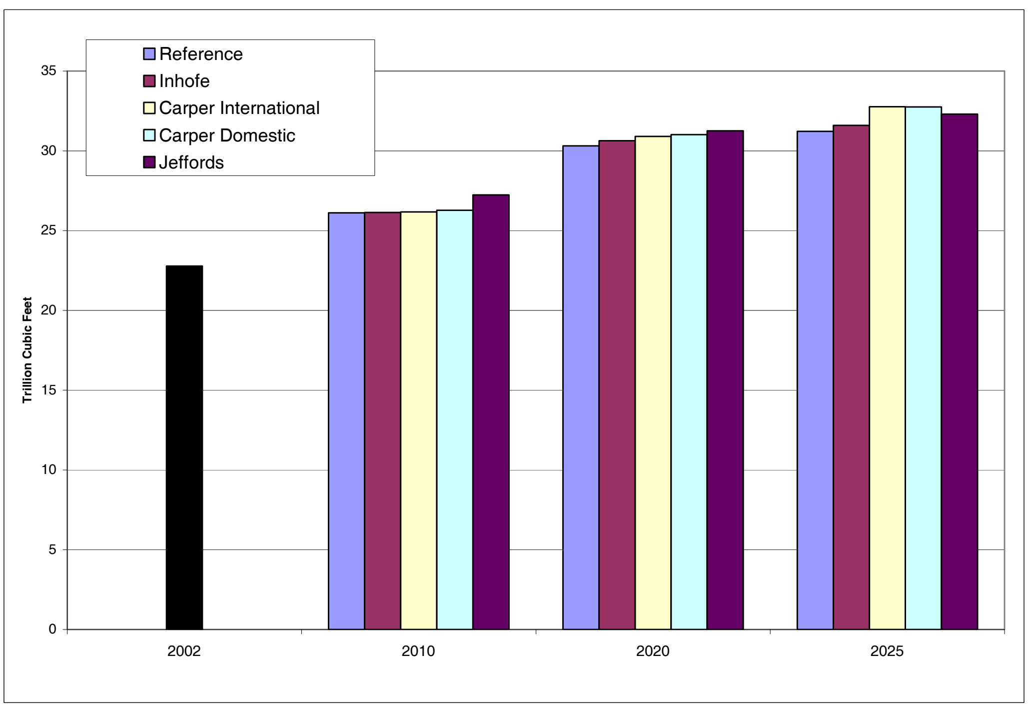
In contrast to coal, natural gas consumption increases relative to the reference case in all of the cases (Figure 11). The increase is generally stronger in the cases with a CO_2 emissions cap. However, in the Jeffords case, which has the most stringent CO_2 emissions cap, the price of natural gas together with the CO_2 allowance fee is projected to be high enough to make new renewable and nuclear technologies more attractive. As a result, growth in natural gas use slows in the later part of the projections in the Jeffords case, falling below the level expected in the Carper cases. Increased use of natural gas is very important in the early years of the Jeffords case because the alternatives are few (mainly natural gas, wind, and biomass cofiring), but in the later years, other renewables, nuclear, and fossil technologies with carbon capture and sequestration equipment are part of the generation capacity mix.

Figure 10. Coal Production in Alternative Cases



Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

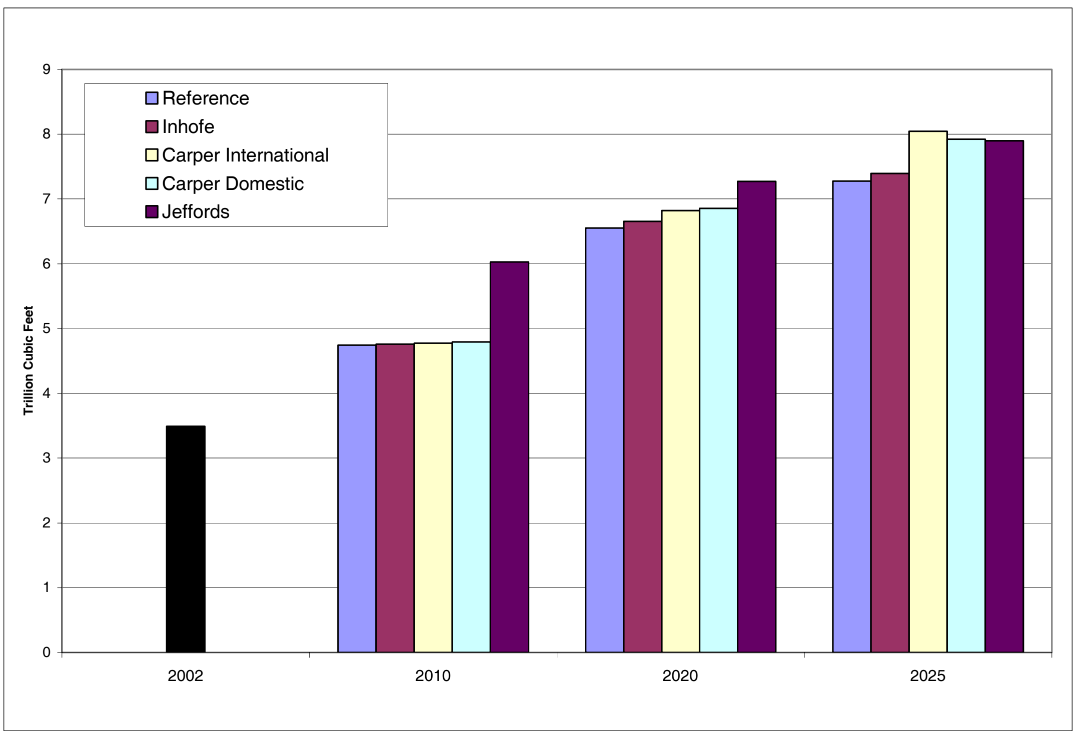
Figure 11. Natural Gas Consumption (All Sectors) in Alternative Cases



Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The increased use of natural gas is projected to lead to increased reliance on natural gas imports, particularly in the Carper cases (Figure 12). Relative to the reference case, in 2020, net natural gas imports are 0.1 trillion cubic feet (tcf) (1.6 percent) higher in the Inhofe case, 0.3 tcf (4.2 percent) higher in the Carper International case, 0.3 tcf (4.7 percent) higher in the Carper case, and 0.7 tcf (11.4 percent) higher in the Jeffords case. By 2025, dependence on natural gas imports is expected to be particularly strong in the Carper International case, where net imports are 0.8 tcf (10.6 percent) above the reference case. In 2025, net imports are projected to account for 24.6 percent of the total gas supply in the Carper International case. The greater imports in the Carper International case come almost entirely from increases in liquefied natural gas (LNG). In the reference case, LNG imports are projected to reach 4.5 tcf in 2025, while in the Carper International case they are expected to reach 5.1 tcf.

Figure 12. Net Natural Gas Imports in Alternative Cases



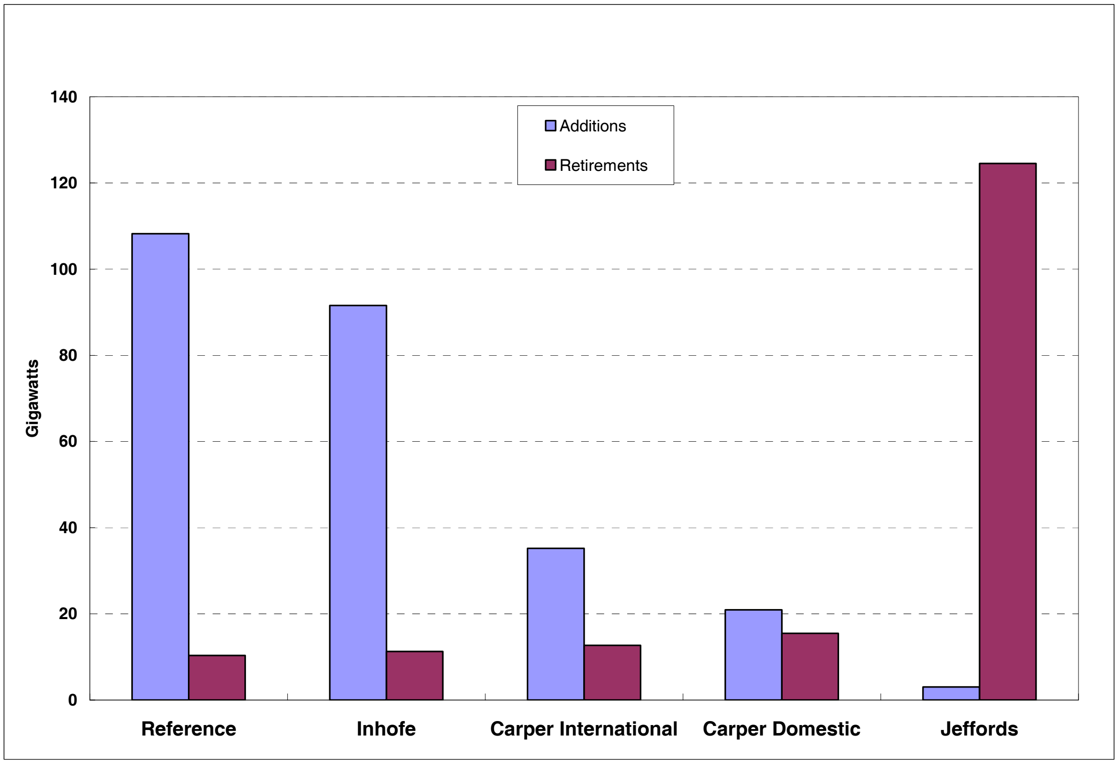
Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Generating Capacity and Pollution Control Equipment Additions

Capacity Additions

As might be expected, coal, natural gas, and renewable capacity changes in the various cases tend to parallel the generation and fuel use changes discussed previously. Under the Inhofe bill, there is a slight reduction in coal plant construction compared to the reference case (Figure 13). New coal capacity additions through 2025 amount to 92 gigawatts under the Inhofe bill compared to 108 gigawatts in the reference case. Because of the CO_2 cap used in the Carper bills, fewer new coal plants will be constructed compared to the Inhofe bill and the reference case. New coal capacity additions through 2025 range from 21 gigawatts to 35 gigawatts under the Carper bill cases.

Figure 13. Cumulative Coal Plant Additions and Retirements, 2002-2025

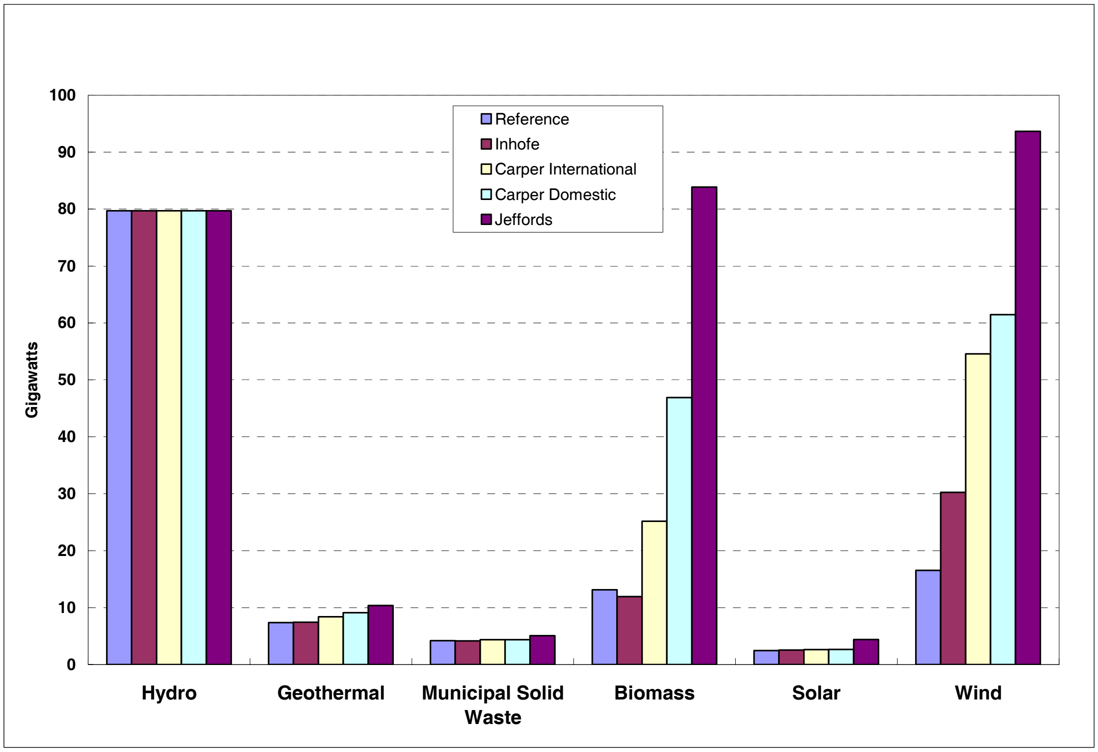


Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The results are different in the Jeffords case due to the comparatively more stringent SO_2, NO_x, mercury, and CO_2 emission targets. Under the Jeffords bill, new coal plant additions are much lower while retirements are higher compared to the reference case. New coal capacity additions through 2025 amount to only 3 gigawatts under the Jeffords bill, and nearly 125 gigawatts of existing coal plants are retired. In addition, the new coal plants that are built are mostly advanced coal plants with carbon capture and sequestration equipment.

In the Carper and Jeffords bills, new renewable capacity is projected to increase significantly (Figure 14). The renewables expected to see the largest growth are biomass and wind. For example, in the Jeffords case, biomass capacity in 2025, including capacity at combined heat and power facilities, is projected to be 84 gigawatts compared to 13 gigawatts in the reference case. Similarly, wind capacity in the Jeffords case in 2025 is projected to be 94 gigawatts compared to 17 gigawatts in the reference case.

Figure 14. Renewable Capacity in 2025



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

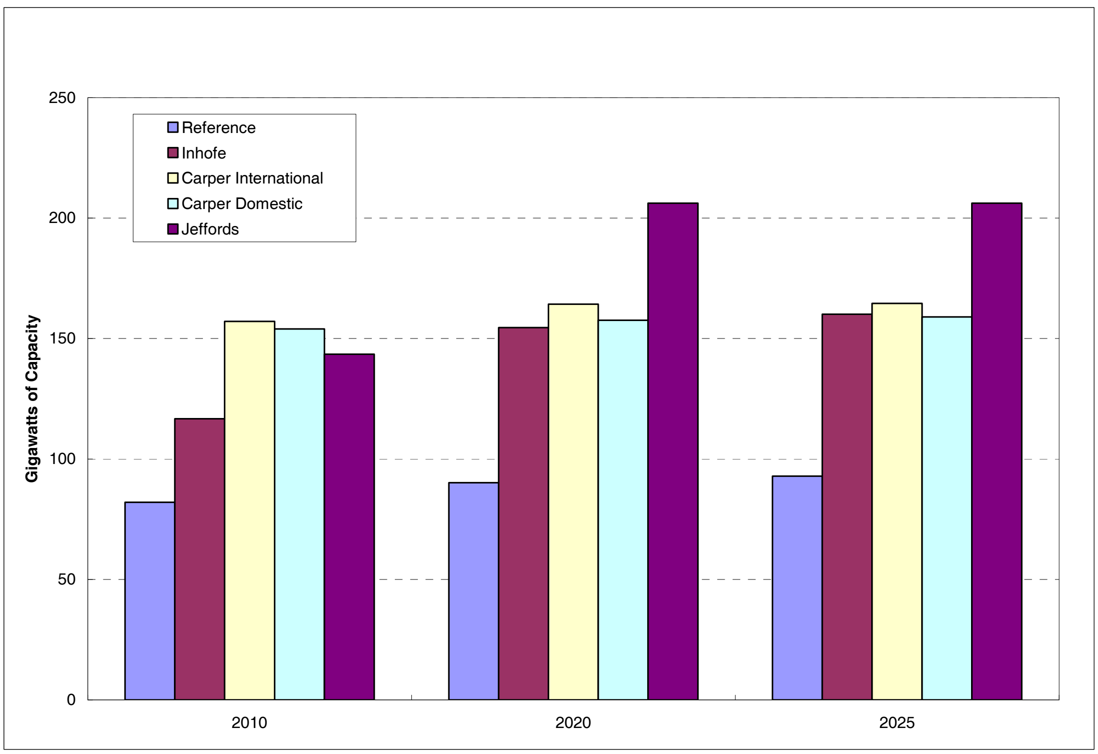
The emissions caps on the power sector also have impacts on power plant additions in the commercial and industrial sectors, including refineries, particularly in the Jeffords case. Since many combined heat and power plants in these sectors are smaller than 15 megawatts and may not sell any power to others, they are not directly covered by the bill. As a result, the higher purchased electricity prices that occur in the Jeffords case provide these facilities with an incentive to build new small electricity facilities and combined heat and power facilities to meet their own needs. In the Jeffords case, 31 additional gigawatts of these end-use facilities are projected to be added, and 6 additional gigawatts of distributed generation facilities are added in the power generation sector. Being able to avoid the costs of CO_2 allowances will make small self-generation facilities increasingly attractive. Because these facilities tend to be less efficient than the larger new facilities, their increased development could raise the costs of complying with the bill. Essentially, for every relatively inefficient small generator built and operated, a larger generator will have to take action to offset its emissions. The relatively high CO_2 allowance fee in the Jeffords case is also projected to stimulate the addition of new nuclear capacity. Between 2014 and 2025, 58 gigawatts of new nuclear capacity are projected to be added in the Jeffords case, increasing total U.S. nuclear capacity by about 60 percent.[14]

[14] Four gigawatts of the total increase in nuclear capacity in the reference case and the Jeffords case result from uprates at existing plants rather than new plant additions.

Pollution Control Equipment

While generating capacity investment decisions are not expected to change significantly in the Inhofe bill, power companies are projected to make significant investments in pollution control equipment to meet the NO_x, SO_2, and mercury caps in all three bills. For NO_x control, they are expected to turn mainly to selective catalytic control (SCR) systems. Under the Inhofe bill, power companies are expected to add 160 gigawatts of SCR capacity by 2025 (Figure 15). SCR additions are expected to be slightly higher under the Carper bill because SCRs also help to reduce mercury emissions for some plants and coal types. With a slightly lower NO_x emissions cap than under Inhofe, the amount of capacity expected to add SCRs in the Carper cases is similar though slightly higher than in the Inhofe case. Between the Carper domestic and international cases, the amount of capacity projected to add SCRs ranges from 159 gigawatts to 165 gigawatts by 2025.

Figure 15. Cumulative SCR Additions, 2002 to 2010, 2020, and 2025

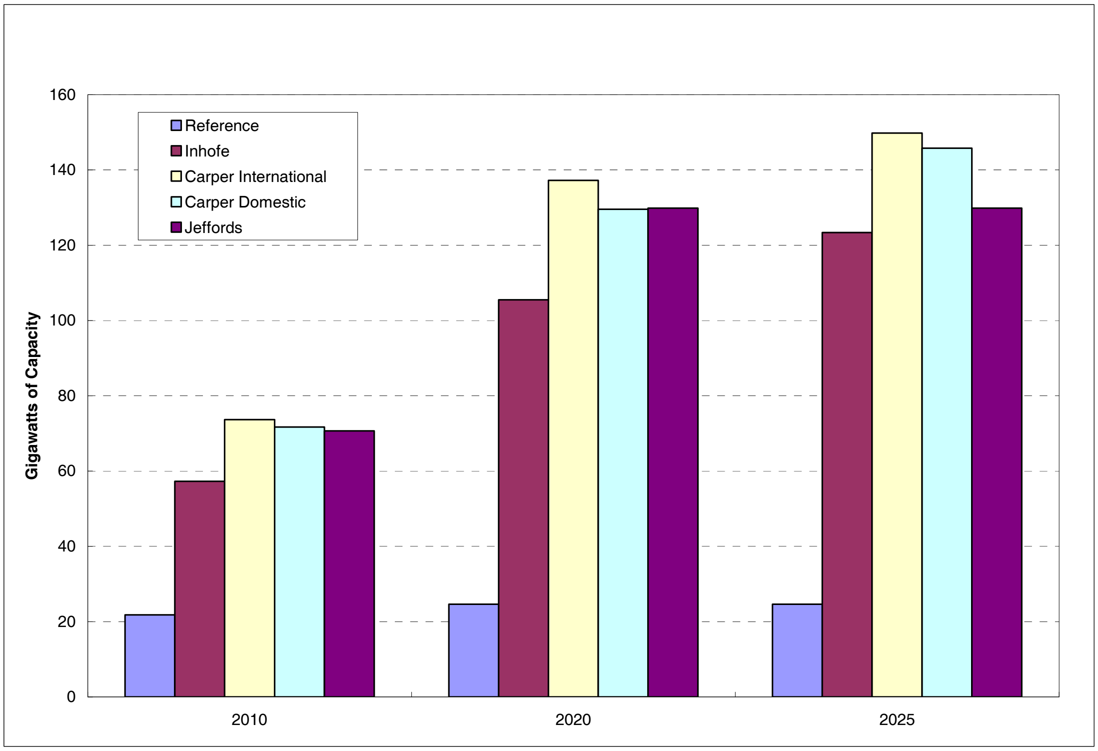


Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Among these three bills, Jeffords has the lowest NO_x emission limit and that limit has to be achieved at the earliest time. In addition, as discussed in the background section, the Jeffords bill has a birthday provision that requires all plants to add the best available control technology by 2014 or 40 years of age, whichever comes later. This essentially means that to continue operating beyond their 40th birthday, all plants must add the best available emission controls. As a result, under the Jeffords bill, power companies are projected to add about 206 gigawatts of SCR capacity by 2025, which is significantly more than in the other cases.

Under the Inhofe bill, power companies are projected to add 123 gigawatts of SO_2 scrubber capacity by 2025 (Figure 16). With approximately 90 gigawatts of SO_2 scrubbers on existing plants today, this means that approximately two-thirds of existing coal capacity will have SO_2 scrubbers by 2025.[15] Those existing plants not adding SO_2 scrubbers are expected to turn to low-sulfur coal to reduce their emissions.

Figure 16. Cumulative SO_2 Scrubber Additions, 2002 to 2010, 2020, and 2025



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

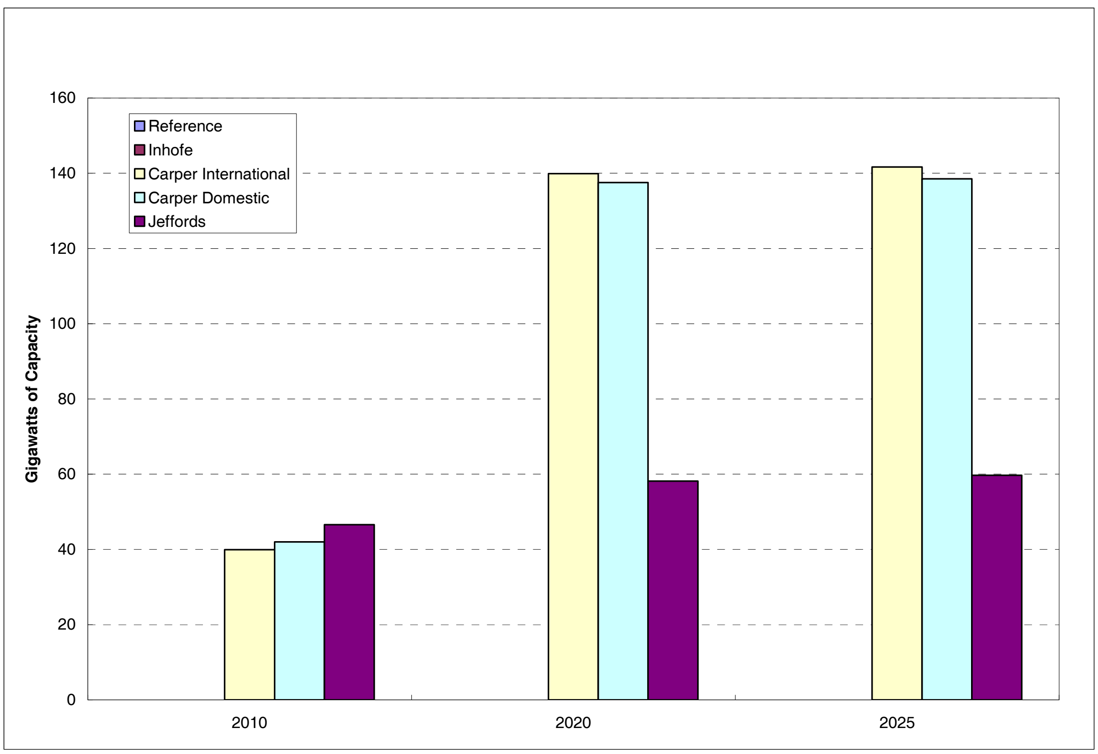
In comparison to the Inhofe bill, the tighter SO_2 emissions cap leads to greater additions of SO_2 scrubbers under the Carper bill cases. In these cases, the amount of capacity adding SO_2 scrubbers is projected to range from 146 gigawatts to 150 gigawatts. The Jeffords bill has the same SO_2 emission cap as the Carper bill, although in the Jeffords bill the cap takes effect earlier than in the Carper bill. By 2025, the amount of SO_2 scrubber additions under the Jeffords bill (130 gigawatts) is similar to that required under the Carper bill. The amount of capacity adding scrubbers is highest in the Carper International case because it has tighter SO_2 and mercury emission limits than the Inhofe

[15] All new coal plants are assumed to be built with SO_2 scrubbers.

bill and the availability of low-cost greenhouse gas offsets means that more coal plants keep operating than in the Carper Domestic or Jeffords cases.

To meet the mercury emissions cap, power plants are expected to partially rely on mercury reductions that come from equipment primarily designed to remove NO_x, SO_2, and particulates[16] and partially on the use of activated carbon injection (ACI) systems designed to specifically remove mercury. ACI can be used with existing particulate control devices (such as electrostatic precipitators or fabric filters) or with a supplemental fabric filter specifically designed to remove mercury. The ACI fabric filter systems are more expensive but are also more effective when a higher percentage of mercury must be removed. Under the Inhofe bill, the mercury removal requirement can be achieved without the need for ACI fabric filters (Figure 17). However, under the Carper bill, the requirement is that all coal plants have to remove at least 70 percent of mercury in the coal that they use and there is a tighter mercury cap. In the Carper case, ACI fabric filter systems are expected to be the key compliance strategy for reducing mercury emissions. By 2025, between 139 gigawatts and 142 gigawatts of capacity are projected to be retrofitted with ACI fabric filter systems in the Carper cases.

Figure 17. Cumulative Supplemental Fabric Filters, 2002 to 2010, 2020, and 2025



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

[16] The removal of mercury as an additional benefit of removing NO_x, SO_2, and particulates is referred to as a co-benefit.

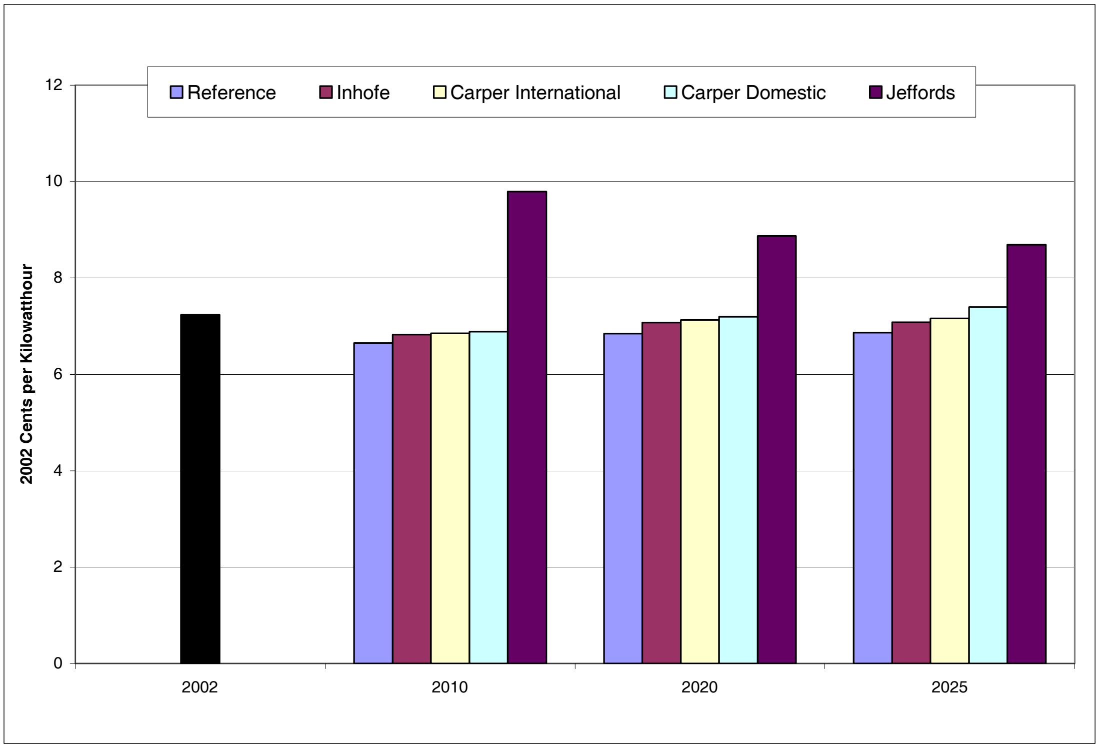
To comply with the generator specific mercury emission requirement in the Jeffords bill, most generators would have to remove over 90 percent of the mercury in the coal they use. For example, the average coal used today contains about 7.3 pounds of mercury per trillion Btu. For a plant that consumes 10,000 Btu of coal per kilowatthour of electricity produced, just over 33 grams of mercury would be produced for each 1,000 megawatthours of electricity generated. Thus, meeting the 2.48 gram per 1,000 megawatthour standard would, on average, require a 93-percent reduction from the level of mercury in the coal. With currently available technologies, it is not known whether this level of removal is achievable for all plant and coal types. This is particularly true for plants using subbituminous and lignite coals. Technologies for removing SO_2 and NO_x are not as successful at removing mercury from these lower rank coals and mercury specific control technologies that can achieve greater than 90-percent removal have not been demonstrated.

The technologies normally represented for mercury removal assume that most plants can only achieve a maximum 90-percent removal. Only plants with full fabric filter systems for particulate control and scrubbers for SO_2 control are assumed to achieve mercury removal levels in excess of 90 percent. To represent the Jeffords bill, it was assumed that plants with cold- or hot-side electrostatic precipitators for particulate control could replace them with full fabric filter systems to achieve 95-percent mercury removal. However, the cost of these retrofits is expected to be high because the existing particulate control systems will have to be removed and significant plant modifications may be needed. To represent these costs, it was assumed that retrofitting full fabric filter systems would cost twice as much as a similar system on a new plant, or approximately $125 per kilowatt. In the Jeffords case nearly 147 gigawatts of coal capacity is projected to be retrofitted with full fabric systems while 60 gigawatts are retrofitted with supplemental fabric filter systems with activated carbon injection to meet the generator specific mercury emission limits.

Electricity Prices, Consumer Electricity, Natural Gas Expenditures, and Industry Resource Costs

Meeting the emissions caps in the Inhofe, Carper, and Jeffords bills is projected to lead to higher electricity prices and industry resource costs. These changes are driven by the increased reliance on higher-cost generating options and the addition of emissions control equipment to reduce NO_x, SO_2, Hg, and CO_2 emissions. The largest price increases are projected in the cases with the more stringent CO_2 emissions caps. In the Inhofe case, electricity prices are projected to be 2.6 and 3.2 percent above the reference case levels in 2010 and 2025, respectively (Figure 18). In the Carper cases, electricity prices are projected to be between 3.0 and 3.6 percent above the reference case level in 2010 and between 4.3 and 7.8 percent above the reference case level in 2025. Of the two Carper cases, the Carper Domestic case is projected to show the larger price increase because only domestic greenhouse gas offsets are assumed to be allowed. The electricity price increases in the Carper cases are dampened by the output-based scheme used to allocate emission allowances. This allocation approach leads to higher overall compliance costs but lower electricity price impacts.

Figure 18. Electricity Prices in Alternative Cases



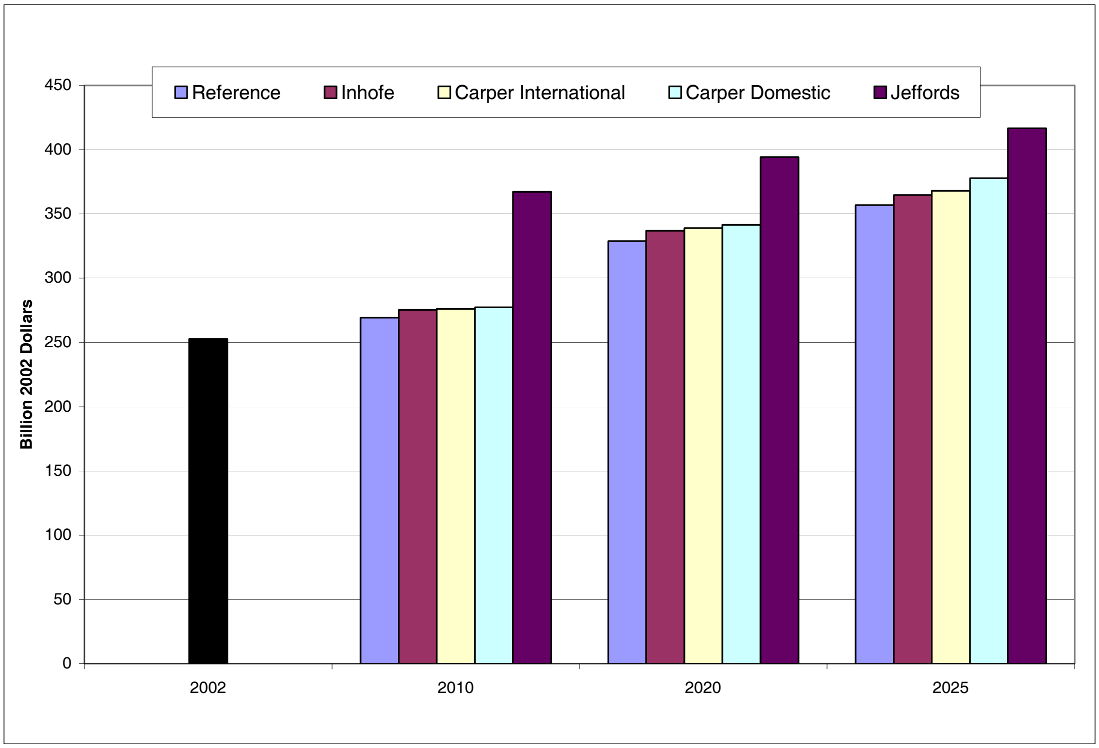
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The largest electricity price increases are expected in the Jeffords case. The near-term timing and stringency of the emission caps, combined with the relatively strict facility specific requirements for mercury control and the birthday provision, are the factors driving the large price increases. Electricity prices, in the Jeffords case, are projected to be 47.2 and 26.5 percent above the reference case levels in 2010 and 2025, respectively. The price impact is largest in the near-term, because meeting the 2009 CO_2 cap requires a rapid industry transformation from coal to natural gas and renewables. Over time, other generating options such as new nuclear, dedicated biomass gasification, and fossil plants with sequestration equipment become available. In addition, as these new technologies penetrate the market their costs are expected to decline, reducing the impact on electricity prices compared to that of 2009.

The changes in consumer expenditures on electricity tend to follow the electricity price changes (Figure 19). However, on a percentage basis, the increases in expenditures are smaller than the electricity price changes because consumers reduce their electricity consumption. In the Inhofe case, electricity use is generally within 1 percent of the reference case level, while it is between 1 and 2 percent below the reference case level in the Carper cases, and 7 to 8 percent below the reference case level in the Jeffords case. Relative to the reference case, the Nation's electricity bill is projected to be $5.9 billion (2002 dollars) (2.2 percent) higher in the Inhofe case in 2010 and $8.0 billion (2.2 percent) higher in 2025. This compares to between $6.8 billion (2.5 percent) and $8.1

billion (3.1 percent) higher in 2010 and between $11.3 billion (3.1 percent) and $21.1 billion (5.7 percent) higher in 2025 in the Carper cases. In the Jeffords case, the Nation's electricity bill is projected to be $97.7 billion (35.2 percent) higher than in the reference case in 2010 and $60.0 billion (15.9 percent) higher in 2025.

Figure 19. National Electricity Bill in Alternative Cases

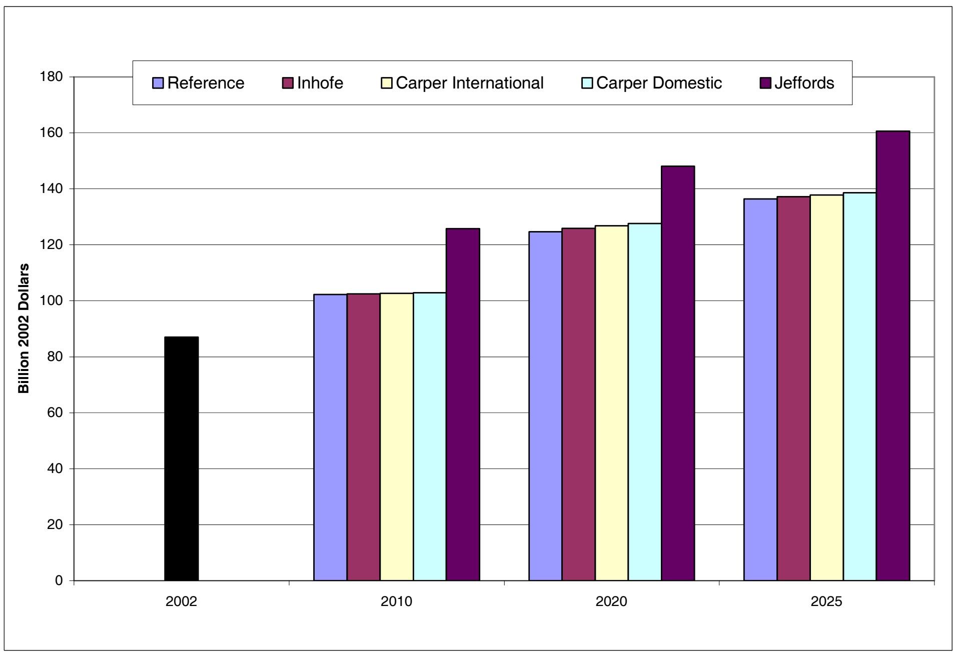


Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The average annual household electricity bill is projected to be $19 and $23 higher in 2010 and 2025, respectively, in the Inhofe case. The average annual household electricity bill is projected to be between $21 and $24 in 2010 and $29 and $57 in 2025 in the Carper cases. The average annual household electricity bill in the Jeffords case is projected to be $305 and $177 higher in 2010 and 2025, respectively.

Consumers are also projected to spend more on natural gas as electricity producers drive up the price of gas by increasing their natural gas consumption (Figure 20). Relative to the reference case, the Nation's nonelectricity sector natural gas bill is projected to be $0.8 billion (2002 dollars) higher in the Inhofe case in 2020. This compares to between $2.1 billion and $2.9 billion higher in the Carper cases and $23.5 billion higher in the Jeffords case. While the impact will vary from region to region, when averaged over the 63 percent of households using natural gas, the annual household natural gas bill in 2020 is projected to be $4 higher in the Inhofe case, $6 to $9 higher in the Carper cases, and $15 higher in the Jeffords case. In the Jeffords case where the greatest impact on gas markets occurs in 2009, the average household increase in natural gas is \$52 (\$83 when just the households using natural gas are included). The relatively large increase in the Jeffords case is due to the stringency of the emissions caps, particularly the CO_2 emissions cap, and the exemption for small generators that do not have to hold allowances. With a projected CO_2 allowance fee of over \$27 per metric ton CO_2 (\$100 per metric ton carbon equivalent), small generators are expected to become increasingly economical.

Figure 20. Nonelectric Sector Natural Gas Bill in Alternative Cases, 2005 through 2025



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The change in electric industry expenditures, referred to as resource costs, also tend to follow the change in electricity prices (Figure 21). To comply with the bills, the industry is projected to spend more on fuel, new plants, emissions control equipment, and supplies such as activated carbon. Over the 2005 through 2025 period, industry resource costs are projected to be 1.3 percent (\$19 billion) higher in the Inhofe case, 2.9 percent (\$42 billion) to 4.5 percent (\$65 billion) higher in the Carper cases and 19.4 percent (\$279 billion) higher in the Jeffords case.[17]

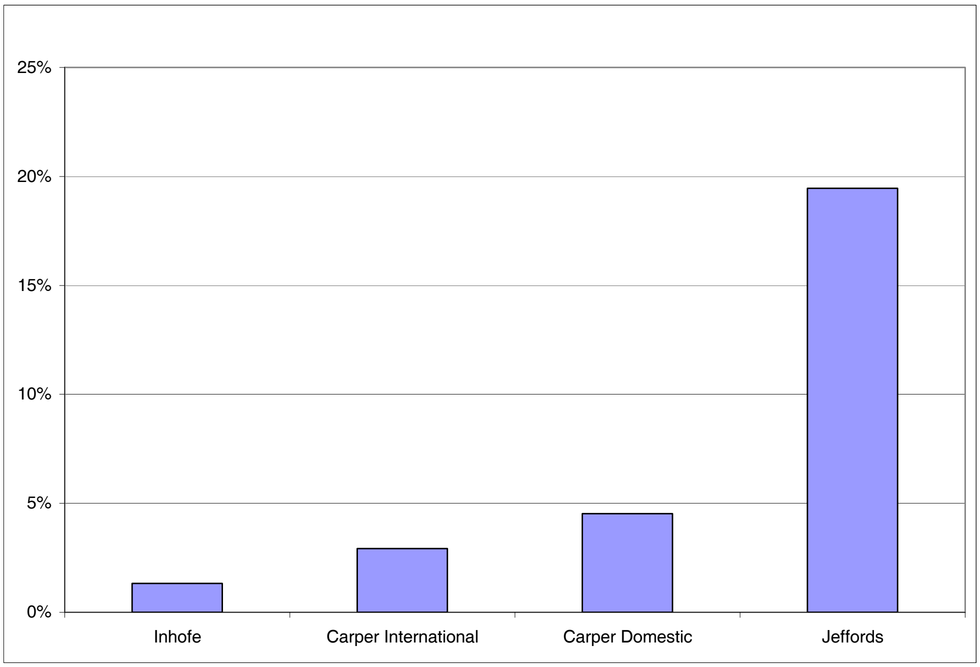
Emissions and Allowance Prices

The emissions data shown in this section are for the electric power sector, which includes all generators whose primary business is to produce and sell electricity. Emissions from

[17] A 7-percent discount rate is used in these calculations.

industrial and commercial facilities that primarily produce power for their own use are not included.

Figure 21. Percentage Change in Electric Industry Costs in Alternative Cases, 2005 through 2025

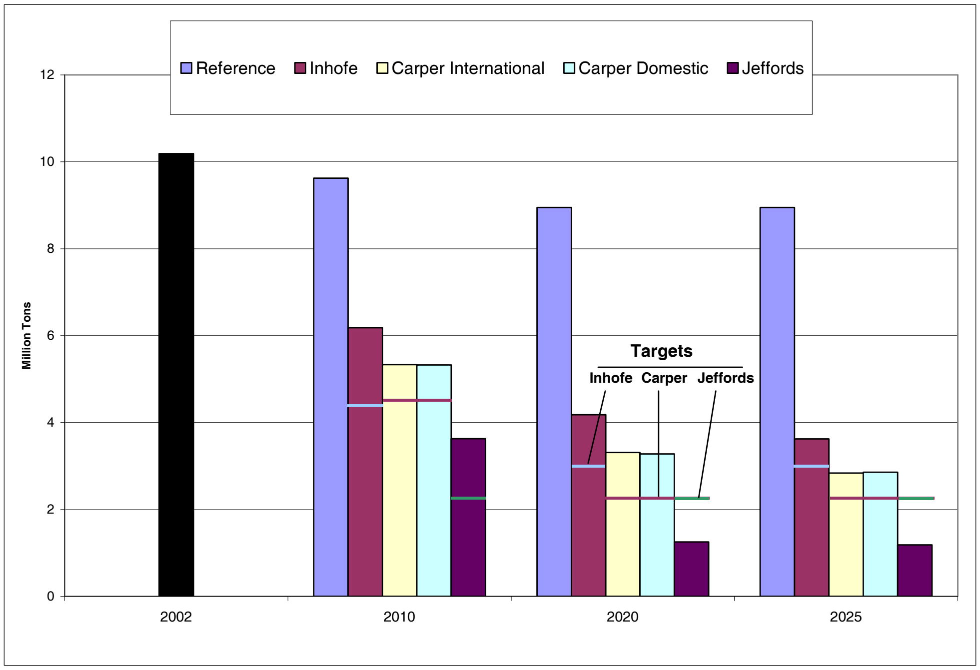


Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Sulfur Dioxide

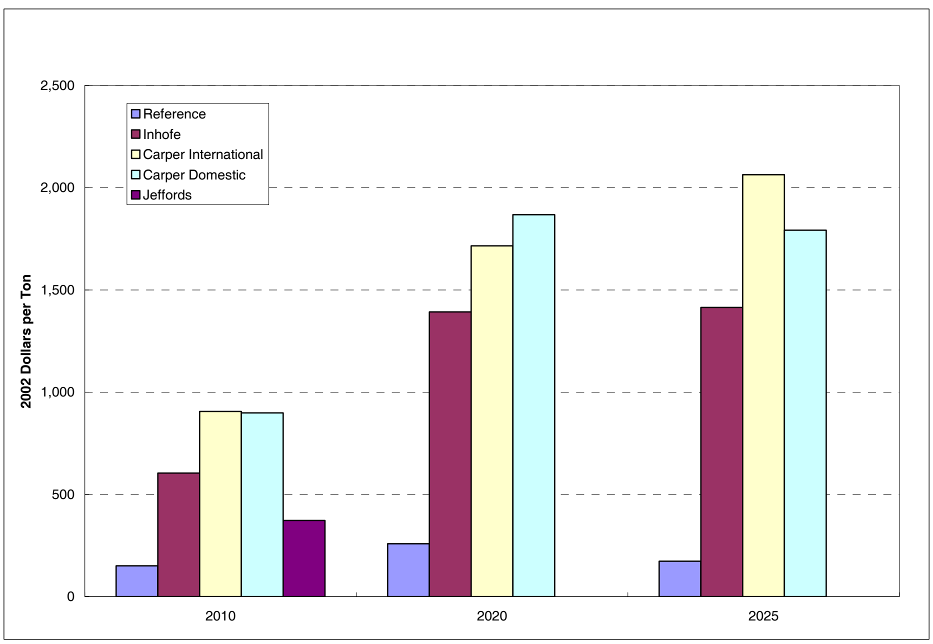
As might be expected, the respective allowance prices are projected to increase as the emissions caps are tightened. For example, under the Inhofe bill, national SO_2 emissions are projected to decline from approximately 10.2 million tons in 2002 to 3.6 million tons in 2025 (Figure 22). Note that because of emission banking, SO_2 emissions are not expected to reach the 3-million-ton target specified for 2018. This target is not even reached by 2025. SO_2 allowance prices under the Inhofe bill are projected to be $605 per ton in 2010 and $1,414 per ton in 2025 (Figure 23). The pattern of SO_2 emissions and allowance prices is similar in the Carper cases, though projected allowance prices are higher due to the lower emissions limits. National SO_2 emissions are projected to decline from approximately 10.2 million tons in 2002 to 2.9 million tons in 2025 in the Carper Domestic case and 2.8 million tons in the Carper International case. There are slight differences between the Carper Domestic and Carper International cases, and these reflect differences in emissions banking patterns in the two cases. Also, as is projected to occur under the Inhofe bill, because of emission banking, SO_2 emissions are not expected to reach the 2.25-million-ton target specified for 2016. This target is, again, not achieved by 2025. SO_2 allowance prices in the Carper Domestic and International cases are

Figure 22. National SO_2 Emissions in Alternative Cases



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 23. SO_2 Allowance Prices in Alternative Cases



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

projected to range from \$898 per ton to \$906 per ton in 2010 and from \$1,792 per ton to \$2,064 per ton in 2025. In the long run, SO_2 allowance prices tend to be lower in the Carper Domestic case than in the Carper International case because higher CO_2 allowance prices lead to lower coal use. This is much higher than the comparable allowance prices under the Inhofe bill.

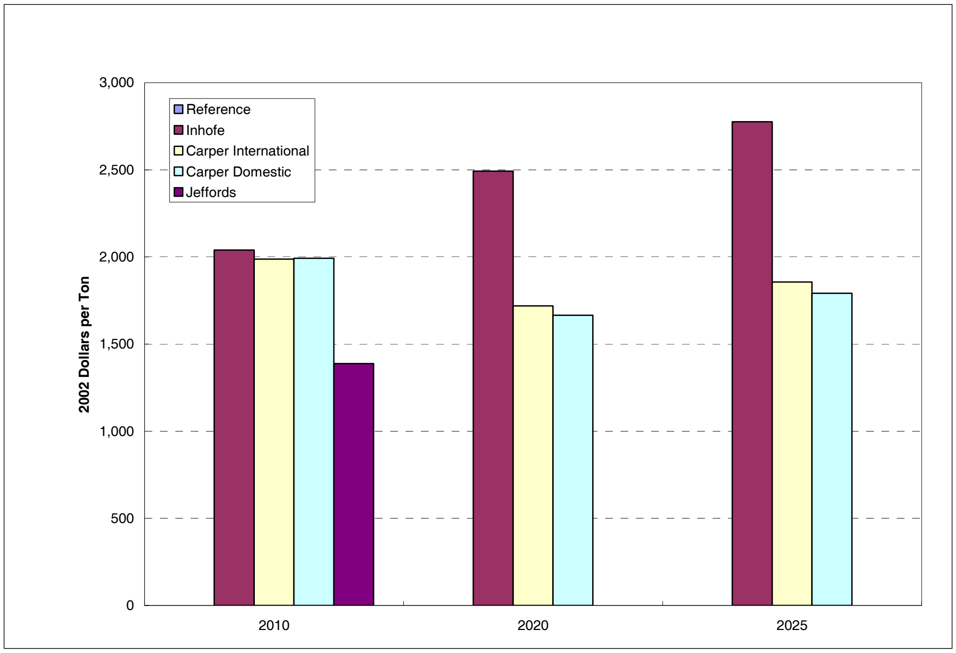
The Jeffords bill is somewhat different from the other bills in that the SO_2 emission cap has to be achieved in 2009 compared to 2016 in the Carper bill and 2018 in the Inhofe bill. In addition, the Jeffords bill has a provision which requires that all plants have to install the best available control technology beginning in 2014 or when they reach 40 years of age, whichever comes later (this is known as the "birthday provision"). Since a reduction of coal use to meet a CO_2 cap would also reduce SO_2 emissions, there are significant synergies between the CO_2 cap and the SO_2 cap in the Jeffords bill. The CO_2 cap under the Jeffords bill is earlier and more stringent than the Carper bill cap. The combined effect of power companies reducing their use of coal to comply with the CO_2 cap and the impact of the birthday provision in the Jeffords bill is that plants over-comply with respect to meeting their SO_2 emissions cap. Under the Jeffords bill, national SO_2 emissions are projected to decline from approximately 10.2 million tons in 2002 to 1.18 million tons in 2025, which is significantly under the emission cap of 2.25 million tons. Because of the CO_2 cap and the birthday provision in the Jeffords bill, SO_2 allowance prices rise to \$373 per ton in 2010 and then decline to zero by 2014.

Nitrogen Oxides

In the Inhofe and Carper domestic and international cases, NO_x emissions are projected to fall from 4.4 million tons in 2002 to about 1.7 to 1.8 million tons by 2025. Both bills meet or are very close to meeting their NO_x emission targets within the required timetables. Unlike for SO_2, because the first and second phase targets are so close, there is not expected to be significant NOx allowance banking during the first reduction phases, so the second phase targets are achieved as scheduled. NO_x allowance prices under the Inhofe bill are projected to be higher in the Eastern United States than in the West (Figures 24 and 25). Generally, eastern region NO_x allowance prices under the Inhofe bill are expected to be in the \$2,040 per ton to \$2,776 per ton range across all years. In contrast, western region allowance prices under the Inhofe bill are expected to be in the \$1,124 to \$1,715 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.

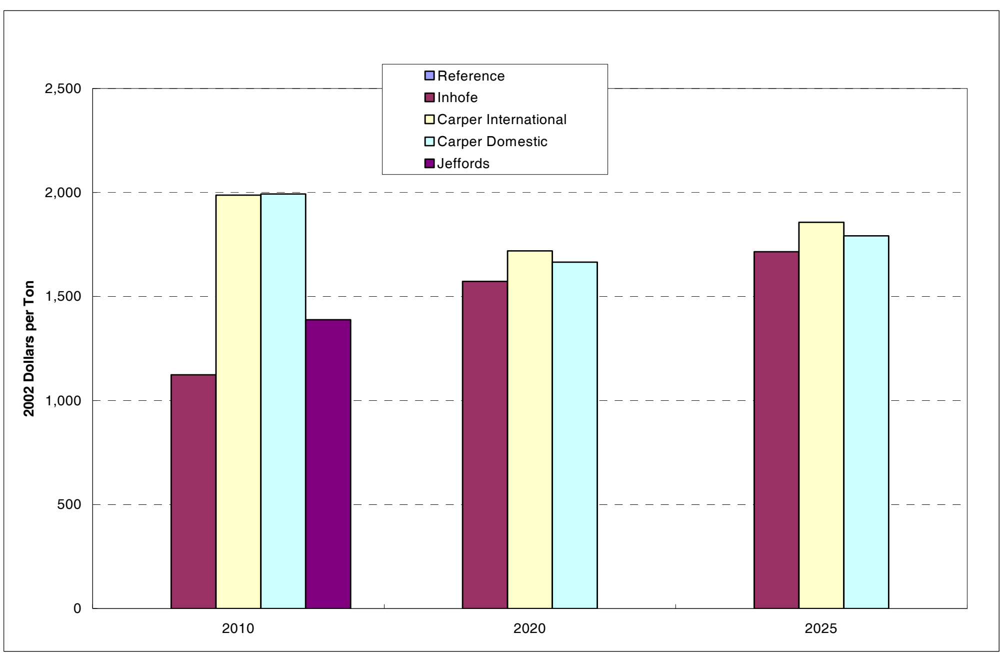
The Carper bill does not differentiate between emission caps in the East and West. The Nation as a whole has to meet the same overall cap regardless of the location of the power plants. Therefore there is no difference in NO_x allowance prices between the East and West under the Carper bill. In 2025, NO_x allowance prices in the Carper Domestic and International cases range from \$1,792 to \$1,857 per ton. The Carper International case results in higher NO_x allowance prices because of synergies between the CO_2 cap and the NO_x cap since a reduction of coal use to meet a CO_2 cap would also reduce NO_x emissions. Under the Carper International case, power companies are able to purchase

Figure 24. Eastern NO_x Allowance Prices in Alternative Cases



Note: Under the Carper and Jeffords bills, the NO_x emissions cap is nationwide, so the east and west allowances prices are the same.
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 25. Western NO_x Allowance Prices in Alternative Cases



Note: Under the Carper and Jeffords bills, the NO_x emissions cap is nationwide, so the east and west allowances prices are the same.
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

greenhouse gas emission offsets from the international and domestic market at lower costs compared to the domestic only offset market in the Carper Domestic case. The availability of international offsets allows more of their existing coal capacity to continue operating while still meeting the CO_2 cap. However, the higher coal capacity results in higher allowance prices for NO_x emissions.

Under the Jeffords bill, the final NO_x emission cap has to be achieved earlier, in 2009 compared to 2013 in the Carper bill and 2018 in the Inhofe bill. The combined effect of power companies reducing their use of coal to comply with the CO_2 cap and the impact of the birthday provision is that plants over-comply with respect to meeting their NO_x emissions cap. Under the Jeffords bill, national NO_x emissions are projected to decline from approximately 4.4 million tons in 2002 to 0.61 million tons in 2025, which is significantly under the emission cap of 1.51 million tons. Because of the CO_2 cap and the birthday provision in the Jeffords bill, NO_x allowance prices rise to $2,042 per ton in 2009 and then decline to zero almost immediately thereafter.

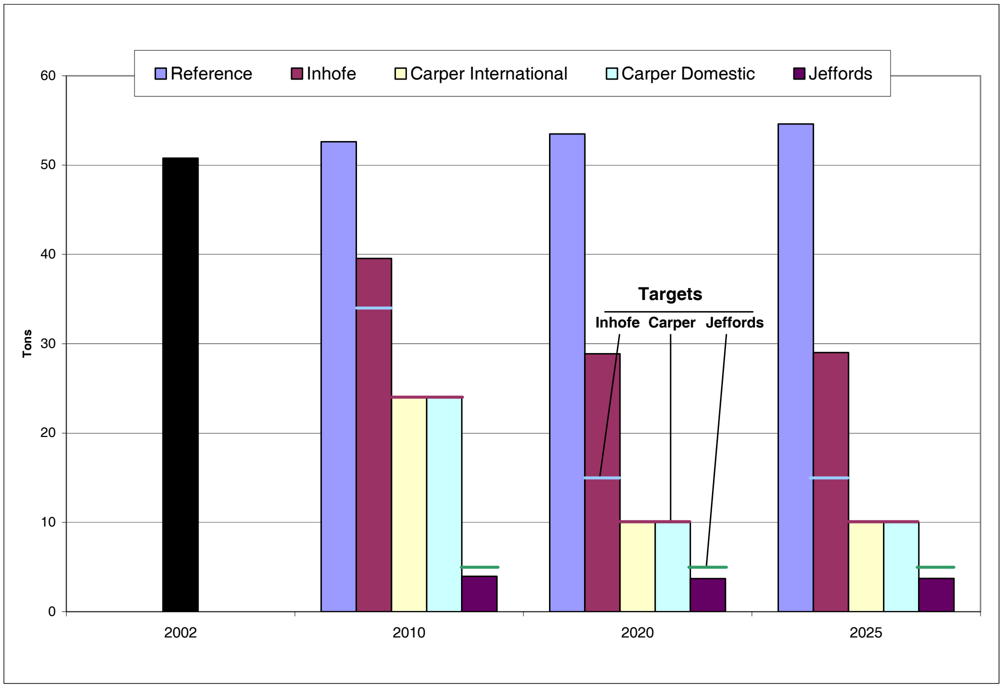
Mercury

Mercury emissions are projected to be below the reference case level under the Inhofe bill (Figure 26). In the reference case, mercury emissions are expected to increase to approximately 55 tons in 2025 as existing coal plants are used more intensively and new coal plants are added. Under the Inhofe bill, 2025 mercury emissions are projected to be only 29 tons because of the combined effect of equipment added to reduce NO_x, SO_2, and mercury. However, mercury emissions are not projected to reach the 2010 or 2018 cap levels because of the early credit program and the mercury safety valve. In 2010 under the Inhofe bill, mercury emissions are expected to be 40 tons (versus a cap of 34 tons), while in 2025 emissions are 29 tons (versus a cap of 15 tons). Mercury emissions are projected to exceed the 34-ton cap in 2010 because of the use of early credits power companies accumulate (bank) prior to the start of the program. In the longer term, mercury emissions are projected to exceed the 15-ton cap that begins in 2018 because of the $35,000-per-pound safety valve on mercury allowance prices (Figure 27).

Under the Carper bill, the pattern of mercury emissions is similar to that of the Inhofe bill, though lower because of the tighter mercury emissions cap and the lack of a mercury allowance safety valve. Mercury emissions are projected to be 10 tons in 2025, much lower than the 55 tons projected in the reference case. The co-benefits of NO_x and SO_2 reduction, the addition of mercury reduction equipment, and reduced coal use are the key drivers in lower mercury emissions. Under the Carper bill, the requirement that all plants remove a minimum of 70 percent of the mercury in the coal also contributes to the reduced mercury emissions. The mercury cap is 10 tons by 2013, which is achieved in both the domestic and international cases of the Carper bill[18]. In the Carper cases, mercury allowance prices in 2025 are projected to be between $55,000-per-pound and $69,000-per-pound. These allowances prices would be higher without the plant-specific mercury reduction requirements. This compares to the $35,000-per-pound allowance price in 2025 under the Inhofe bill, due to the limit imposed by the safety valve.

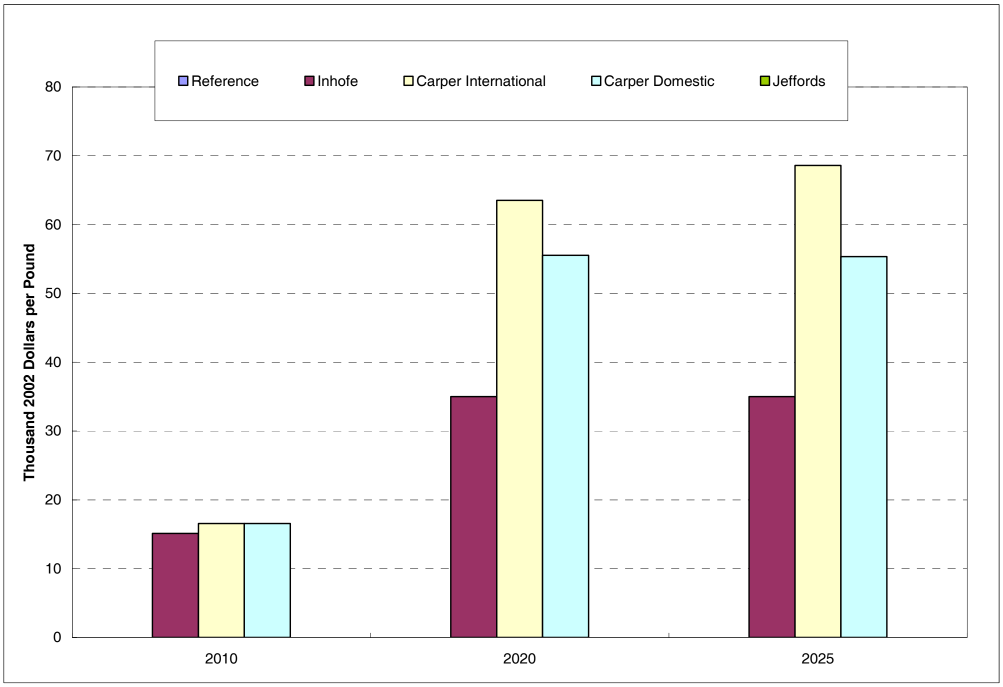
[18] The Carper bill requires that all coal facilities either remove a minimum percentage (50 percent) between 2009 and 2012, and 70 percent in 2013 and later) of the mercury in the coal burned or meet an output-based rate to be set by the EPA Administrator.

Figure 26. National Mercury Emissions in Alternative Cases



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 27. Mercury Allowance Prices in Alternative Cases



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

The Jeffords bill sets a facility-specific mercury emissions limit of 2.48 grams per 1,000 megawatthours. This is an emissions limit, not an allocation of allowances, and it does not allow for banking or trading of allowances. The emission limit in the Jeffords bill is set to achieve an overall mercury emissions cap of 5 tons by 2009, much earlier than the final caps in the Carper and Inhofe bills, which take effect in 2013 and 2018, respectively. However, because coal use is projected to fall because of the CO_2 emissions cap, the mercury emissions are expected to be 3.7 tons in 2025, 1.3 tons under the 5-ton emissions target. This is partially achieved through the co-benefits associated with the installation of NO_x and SO_2 control equipment. However, the primary strategy is expected to be the addition of fabric filters and activated carbon injection systems to reduce mercury.

Carbon Dioxide

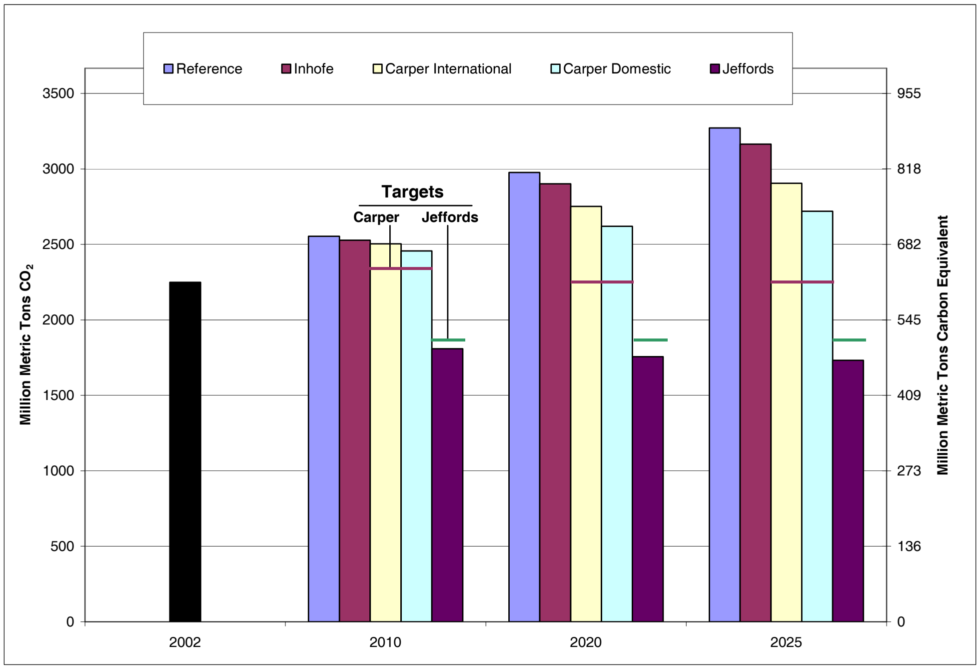
Under the reference case assumptions, CO_2 emissions from the generation sector in 2025 are projected to be 3,271 million metric tons (892 million metric tons carbon equivalent). There are no CO_2 caps under the Inhofe bill; however, because of NO_x, SO_2, and mercury caps, there is a slight shift from coal to natural gas. This shift results in a decline in CO_2 emissions in the Inhofe bill compared to the reference case. In 2025, CO_2 emissions under the Inhofe bill are projected to be 3,164 million metric tons (863 million metric tons carbon equivalent), about 3 percent below the reference case level.

The Carper bill requires a reduction in CO_2 emissions to 2,244 million metric tons (612 million metric tons of carbon equivalent) by 2013. Although the Carper cases have lower CO_2 emissions than under the Inhofe bill, neither the Carper Domestic or International cases achieve this target because of the use of greenhouse gas offsets. The projected change in CO_2 emissions in the Carper Domestic and International cases depends on the availability and cost of offsets (Figure 28). In the Carper Domestic case, generation companies are projected to rely primarily on offsets available in the domestic U.S. market. In the Carper International case, a greater amount of offsets are available at a lower cost from the international offset market. Therefore, in the Carper Domestic case the CO_2 emissions in 2025 are projected to be 2,721 million metric tons (742 million metric tons carbon equivalent). In the Carper International case, generation companies rely more on international offsets rather than direct emission reductions to meet the CO_2 cap. Therefore the CO_2 emissions are projected to be higher, 2,904 million metric tons (792 million metric tons carbon equivalent) in 2025.

CO_2 allowance prices are projected to vary significantly across the Carper cases (Figure 29). In 2010, CO_2 allowance prices are projected to range from \$1 to \$6 per metric ton (\$5 to \$22 per metric ton carbon equivalent), while in 2025 the range widens to between \$7 to \$17 per metric ton (\$27 and \$61 per metric ton carbon equivalent). The increase over time is driven by the growing demand for electricity and resulting need for greater emissions reductions from the reference case level.

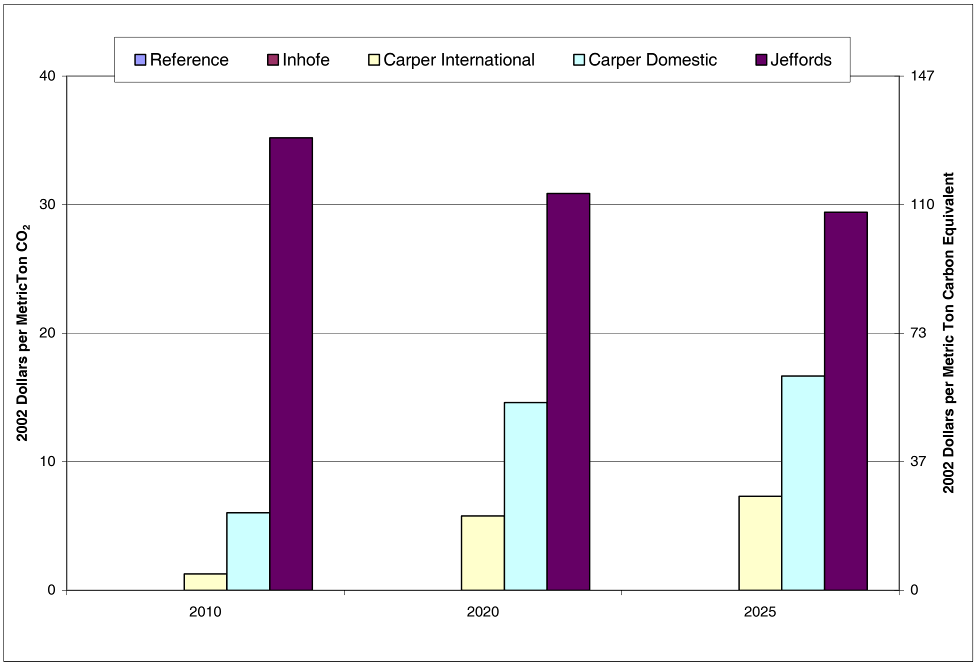
The Jeffords bill calls for a reduction to 1,863 million metric tons of CO_2 (508 million metric tons carbon equivalent) by 2009 (which is approximately the 1990 level of CO_2 emissions from the electricity sector) and it does not allow for emissions offsets.

Figure 28. Electricity Sector Carbon Dioxide Emissions in Alternative Cases



Note: The CO_2 target in the Jeffords bill is adjusted downward to cover the emissions from the new small generation and combined heat and power facilities.
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 29. Carbon Dioxide Allowance Prices in Alternative Cases



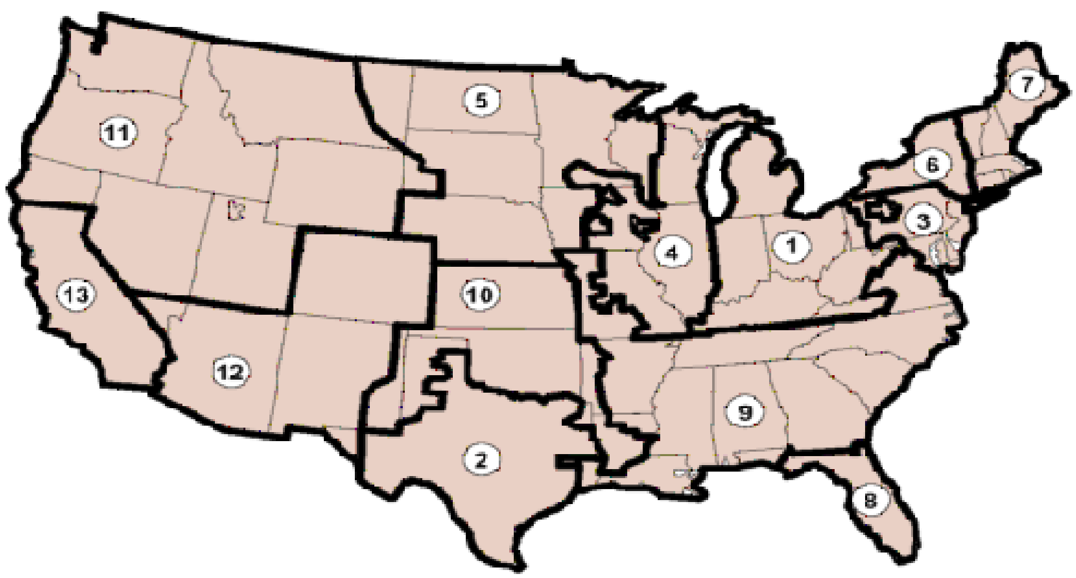
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

However, because the emissions of small generators, including those in the residential, commercial, and industrial sectors, must be offset by emissions reductions in larger, covered generators the cap is projected to decline slightly over time. Electricity sector CO_2 emissions in the Jeffords bill are projected be 1,808 million metric tons (493 million metric tons carbon equivalent) in 2010 and 1,732 million metric tons (472 million metric tons carbon equivalent) in 2025. Because it is only 5 years away, meeting the 2009 cap is expected to be particularly challenging because the near-term options for lower emission technologies are limited to the increased use of natural gas or renewables such as wind and biomass cofiring. As a result, CO_2 allowance prices in 2009 are projected to be quite high, over $58 per metric ton of CO_2 ($212 per metric ton carbon equivalent). Over the longer term, they are projected to be lower, generally ranging between $29 and $42 per metric ton CO_2 ($108 and $155 per metric ton carbon equivalent). Over time, other generating options such as new nuclear, dedicated biomass gasification, and fossil plants with sequestration equipment become available and the carbon allowance price declines.

Regional Emissions

NEMS reports regional results for the electric power sector based on reliability council regions and sub-regions (Figure 30). Under the Inhofe bill, NO_x, SO_2, and mercury

Figure 30. Electricity Regions in the National Energy Modeling System



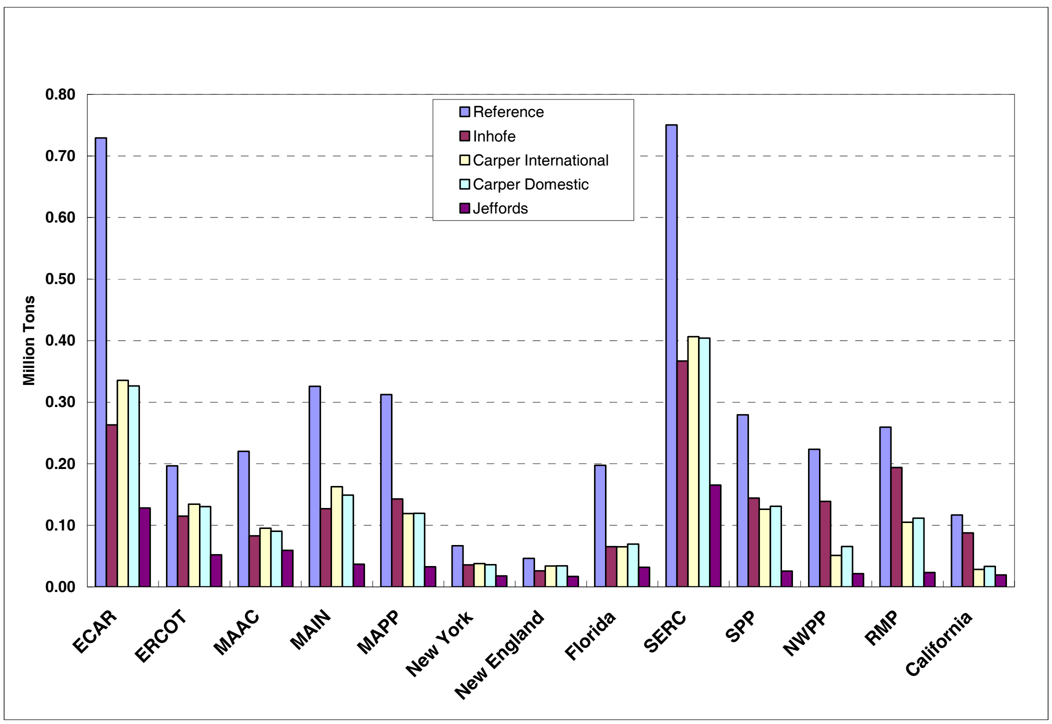
1. East Central Area Reliability Coordination Agreement (ECAR)
2. Electric Reliability Council of Texas (ERCOT)
3. Mid-Atlantic Area Council (MAAC)
4. Mid-America Interconnected Network (MAIN)
5. Mid-Continent Area Power Pool (MAPP)
6. New York
7. New England
8. Florida
9. Southeastern Electric Reliability 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, http://www.eia.doe.gov/oiaf/aeo/supplement/supmap.pdf.

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 31, 32, and 33). Large, heavily coal-dependant regions such as ECAR and SERC are projected to show the largest reductions in NO_x and SO_2 emissions under the Inhofe bill. Despite the fact that there is no CO_2 cap in the Inhofe bill there is a slight reduction in CO_2 emissions due to the indirect effect of the NO_x, SO_2, and mercury caps. The combined effect of these caps creates a slight shift away from coal to natural gas and renewables for the power industry, which leads to reduced CO_2 emissions.

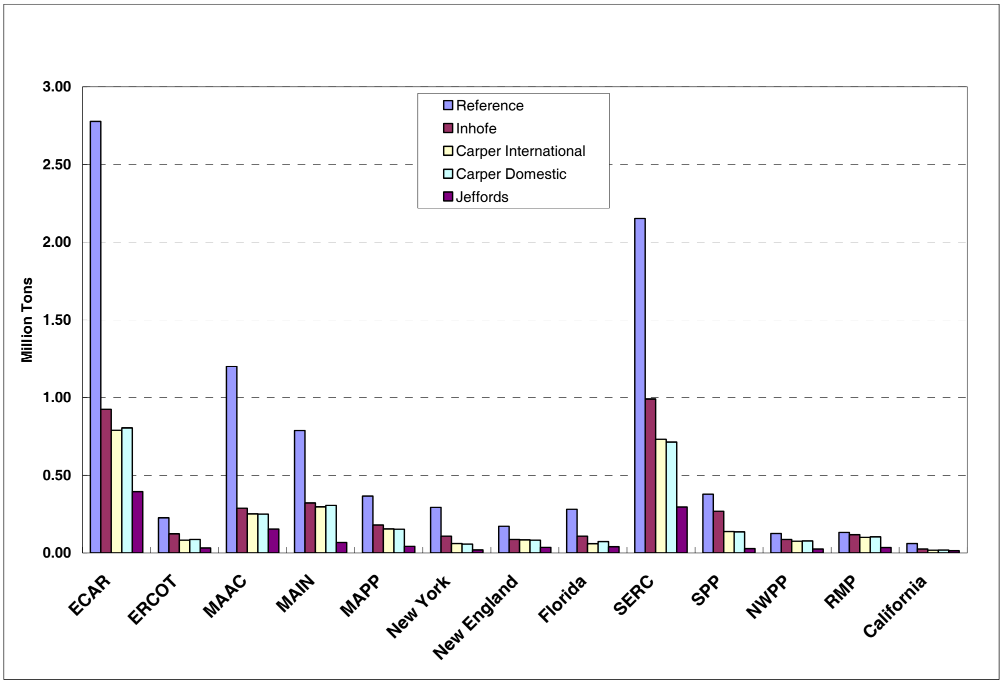
In the Carper and Jeffords cases, NO_x, SO_2, and CO_2 emissions are also projected to fall in most of the regions of the country. Because of the tighter emissions caps and earlier reduction schedule, the regional emissions in 2025 are lower than under the Inhofe bill. As under the Inhofe bill, the largest changes are in regions where coal supplies a large share of the generation, specifically ECAR and SERC.

Figure 31. Regional NO_x Emissions, 2025



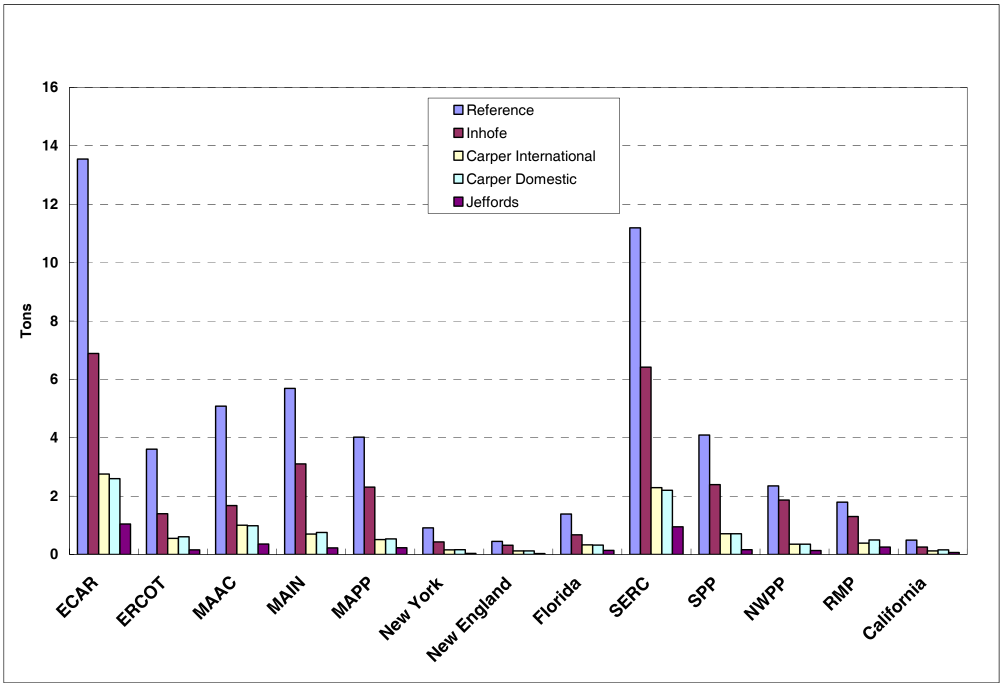
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 32. Regional SO_2 Emissions, 2025



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 33. Regional Mercury Emissions, 2025



Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Economic and Employment Impacts

The imposition of emission limits on the generation sector affects the whole U.S. economy through higher delivered energy prices. As energy prices increase, the cost of production rises, especially for energy-intensive goods, placing upward pressure on the prices of intermediate and final goods and services. Investment and consumer spending decisions will be affected. At the same time, the Federal Reserve Board may seek to balance the adverse effects of higher energy prices by making adjustments to the Federal Funds rate. The adjustments would be designed to moderate the possible impacts on both inflation and unemployment, and to return the economy toward its long-run growth path.

The way that emissions revenue is distributed also has an impact on the economy. The Inhofe and Carper bills allocate allowances to the generation sector either through grandfathering or on an output basis. The effect on energy prices is relatively small because the costs for the generation sector as a whole are relatively small. In the Jeffords case, emissions revenue is collected and distributed according to an allocation scheme. Most of it is given to households consuming electricity; a smaller portion is allocated to renewable generating units, efficiency projects, cleaner energy sources, and to sequestration. Between 2009 and 2018 a declining share is put aside for transition assistance to dislocated workers, hard hit communities and makers of electricity intensive products. Energy prices are expected to rise sharply because of the more stringent CO_2 emissions cap, and the impacts on the economy are more widespread.

Because of the size of the U.S. economy, nearly $10 trillion dollars in 2002, a relatively small decline in economic growth over time can lead to large dollar costs that are a small percent of total Gross Domestic Product (GDP). For example, a 0.1 percent loss in economic output in a $10 trillion economy amounts to a $10 billion loss in a single year. For this reason, it is probably best to focus on the percentage changes in economic output rather than the estimated dollar impacts. Readers should keep the size of the U.S. economy in mind when reviewing the estimated economic costs of the bills. Similarly, the reader should be aware that total U.S. non-farm employment currently exceeds 130 million people. As with economic output, a relatively small percentage loss in employment of 0.1 percent would amount to a loss in employment of 130 thousand.

In the Jeffords case, the wholesale price index for all fuel and power is projected to rise by 48 percent above the reference case in 2009. The price hike slows as the economy adjusts to the new emissions caps and the redistribution of revenue. By 2025, the wholesale price index is expected to be 18 percent above the reference case. Higher energy prices affect all industrial sectors. The industry-wide wholesale price index is projected to be 9 percent above the reference case in 2009, and to be gradually reduced to 4 percent above the reference case by 2025. On an even broader level, the effect on the Consumer Price Index (CPI) is much less acute, varying from 2.5 percent above the reference case in 2013 down to 1.3 percent above the reference case by 2025.

Higher energy prices impact the production of goods and services and consumer spending. The lump-sum transfer of revenue to consumers alleviates some of the burden of the price increases, but overall consumer spending will still be impacted. In the

Jeffords case, consumer spending is expected to be reduced by 1.4 percent from the reference case in 2010, while investment is reduced by 4 percent because of the increase in production costs. The economy as a whole, as measured by the real GDP, is projected to fall by 1.5 percent from the reference case in 2010. After 2010, higher energy costs will shift production toward less energy-intensive sectors and more energy-efficient processing and will encourage energy conservation. Energy prices, producer prices, and sales prices begin to stabilize, and consumption and investment begin to recover. As the economy moves toward the long-run equilibrium path, real GDP is projected to be about 0.1 percent lower than the reference case level from 2017 onwards.

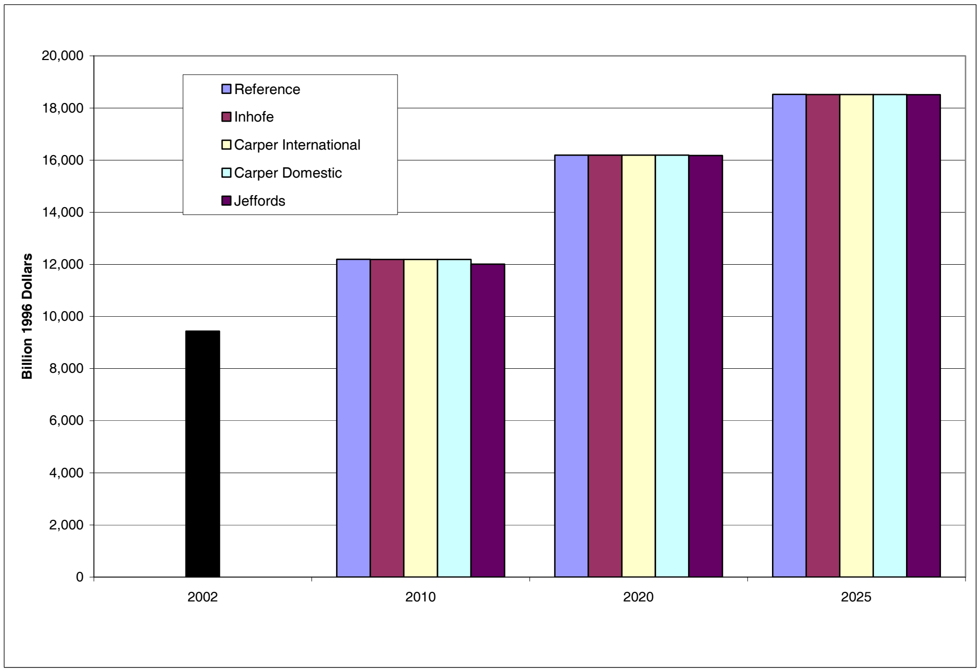
Under the Carper Domestic case, the wholesale price index for all fuel and power is projected to rise by less than 5 percent above the reference case throughout the implementation period. The impact on the CPI is less than 0.3 percent per year, and the impact on real GDP is less than -0.1 percent per year in general, with a maximum impact of -0.11 percent in 2014. The economic impact of the Carper International case is very similar to the Carper Domestic case.

The wholesale price index for all fuel and power in the Inhofe bill rises by less than 2 percent above the reference case throughout the implementation period. The impact on the CPI is less than 0.2 percent per year, and the impact on real GDP is less than -0.06 percent per year.

Figure 34 shows the projected total GDP in the alternative cases. The differences are small when compared to total GDP. Since the impacts on the economy vary from year to year, a consistent way of comparing the impact across cases is to compute the percentage change in cumulative real GDP from 2009 through 2025. Figure 35 shows the percentage change in the cumulative sum and the present value of real GDP, using a real discount rate of 7 percent. The percentage change in these two values is estimated to fall between -0.4 percent and -0.5 percent of the economy's aggregate output between 2009 and 2025. In dollar terms the cumulative change in real GDP in the Jeffords bill is projected to be -$947 billion and the present value loss, -$527 billion. These figures compare to a cumulative sum for total GDP of $255 trillion and a present value sum of $107 trillion. In the Carper International case, the percentage change is projected to fall between -0.05 and -0.06 percent of aggregate output. In dollar terms, this amounts to a change in cumulative real GDP of -$135 billion, with a present value change of -$60 billion. In the Carper Domestic case, the percentage change is projected to be -0.05 percent of aggregate output, with the dollar change in cumulative real GDP being -$134 billion, and the present value change is -$58 billion. The percent change in aggregate output in the Inhofe cases is projected to be -0.03 percent, while the cumulative change in real GDP is -$73 billion and the present value change is -$36 billion.

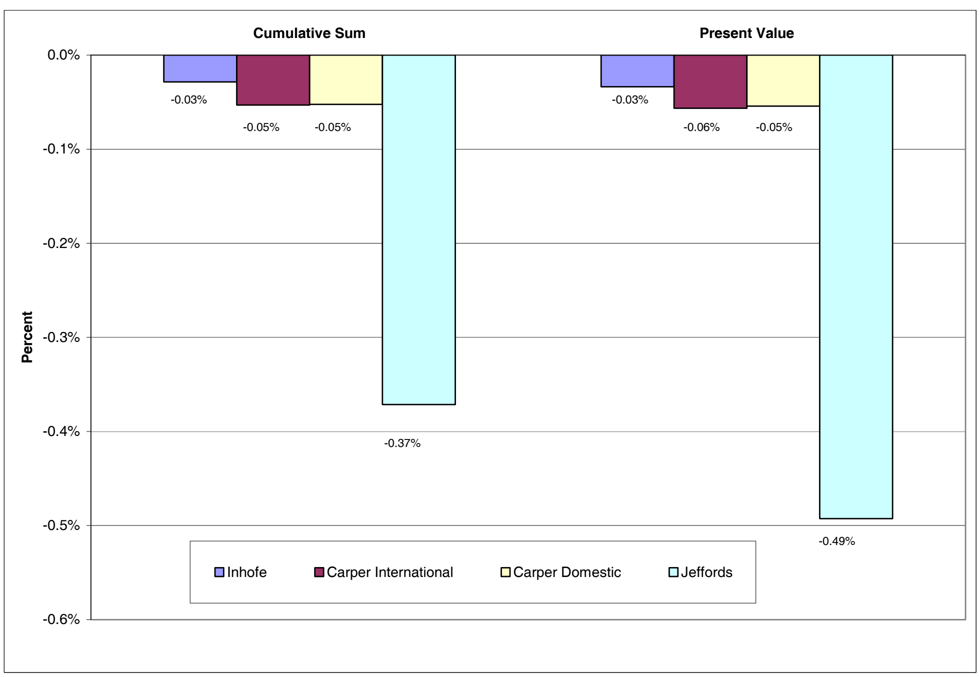
The loss in economic output has an impact on employment. Figure 36 shows the average annual loss in jobs between 2009 and 2025. Total nonfarm employment is projected to be reduced by an annual average 272 thousand (0.17 percent) in the Jeffords bill, by 46 thousand (0.03 percent) in the Carper International case, by 43 thousand (0.03 percent) in the Carper Domestic case, and by 22 thousand (0.01 percent) in the Inhofe bill. For the manufacturing sector, the projected losses are 154 thousand (1.0 percent), 23 thousand (0.14 percent), 15 thousand (0.1 percent), and 8 thousand (0.05 percent), respectively.

Figure 34. Total GDP in Alternative Cases



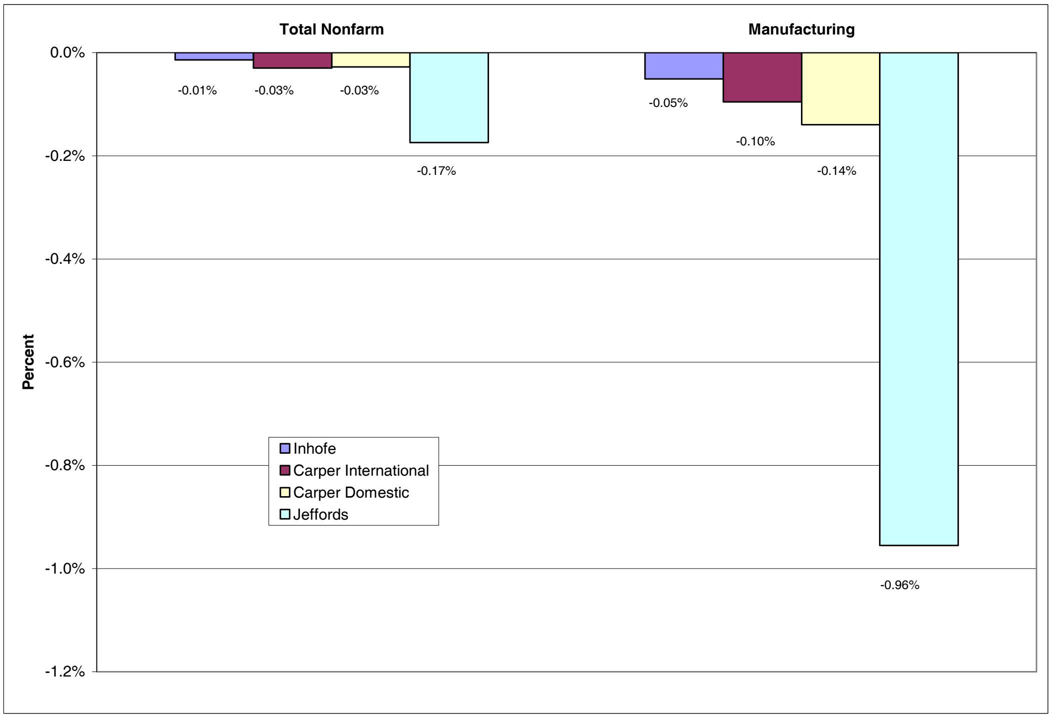
Source: National Energy Modeling System, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 35. Percentage Change in Cumulative Sum and Present Value of Real GDP, 2009-2025



Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Figure 36. Average Annual Percent Change in Employment, 2009-2025



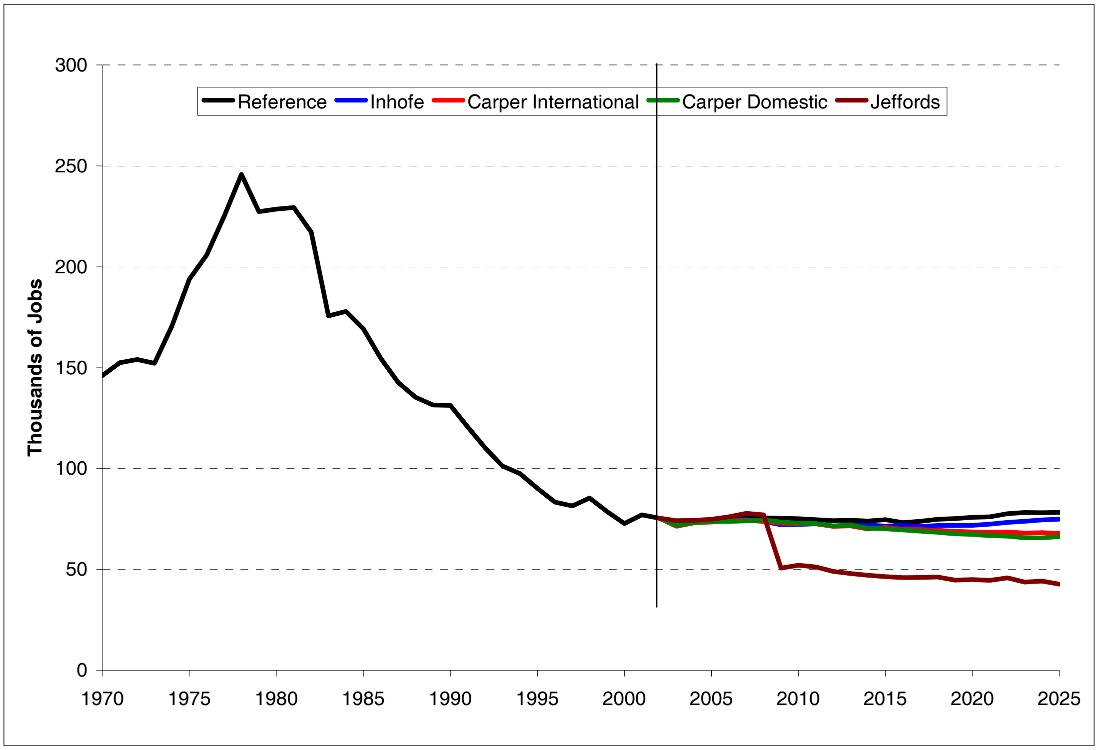
Source: National Energy Modeling System Runs, inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

Employment is expected to be particularly impacted in the coal industry. Between 1978 and 2002, the number of workers employed at U.S. coal mines fell by 4.8 percent per year, declining from 246,000 to 75,000. The decrease primarily reflected strong growth in labor productivity, which increased at an annual rate of 5.8 percent over the same period. An additional factor contributing to the employment decline was the increased output from large surface mines in the Powder River Basin (Wyoming and Montana), which require much less labor per ton of output than mines located in the Interior and Appalachian regions.

In the reference case, productivity improvements are assumed to continue in most regions of the country, but at a considerably slower pace. Different rates of improvement are assumed by region and by mine type, surface and underground. On a national basis, coal mining labor productivity in the reference case increases at an average rate of 1.3 percent per year over the forecast horizon.

In the reference case, the expectation that the rate of productivity improvements will slow over the forecast horizon combined with projections of continuing increases in coal production lead to a relatively stable outlook for U.S. coal mine employment. In this case, coal industry employment is projected to remain near current levels of 75,000 through 2020, increasing slightly thereafter to 78,000 by 2025 as increases in production outpace expected improvements in productivity (Figure 37).

Figure 37. U.S. Coal Mine Employment, 1970-2025



Sources: **History:** 1970-1976: U.S. Department of the Interior, Bureau of Mines, *Minerals Yearbooks*; 1977-1978: Energy Information Administration (EIA), *Energy Data Report, Coal-Bituminous and Lignite*, DOE/EIA-0118 and EIA, *Energy Data Report, Coal-Pennsylvania Anthracite*, DOE/EIA-0119; 1979-1992: EIA, *Coal Production*, DOE/EIA-0118; 1993-2000: EIA, *Coal Industry Annual*, DOE/EIA-0584; 2001-2002: EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003). **Projections:** National Energy Modeling System, runs inbase.d040904a, incs3pws.d040904a, inca4p.d040904a, inca4plo.d040904a, and injf4p.d041604a.

In both the Carper and Jeffords cases, lower levels of coal production relative to the reference case result in lower coal industry employment. In the Carper Domestic case, coal mine employment is projected to decline by 0.6 percent per year, falling from 75,000 in 2002 to 66,000 by 2025. Due to the increased availability of greenhouse gas offsets in the Carper International case, a slightly smaller decline in employment is projected in this case than in the Carper Domestic case, where a larger falloff in coal production is projected. In the Jeffords case, a considerably more restrictive cap on CO_2 emissions, relative to the Carper cases, results in higher greenhouse gas emission allowance prices, and, subsequently, lower levels of coal production and employment. In this case, coal mine employment is projected to decline by 2.5 percent per year, falling from 75,000 in 2002 to 43,000 by 2025. Relative to the reference case, U.S. coal mine employment in 2025 is projected to be reduced by 12,000 in the Carper Domestic case, by 10,000 in the Carper International case, and by 36,000 in the Jeffords case. In the Inhofe case, U.S. coal mine employment is projected to be only slightly lower than projected in the reference case.

Oil and gas extraction jobs generally track the number of oil and gas wells drilled. With the exception of the Jeffords case, domestic crude oil and natural gas production and drilling closely track the pattern and levels in the reference case. As a result, the difference in employment in the oil and gas extraction industry for the Carper and Inhofe cases ranges from 2,900 additional to 2,700 fewer jobs than the reference case in any year. Cumulatively from 2003 through 2025, the number of oil and gas extraction job-years is higher than in the reference case by 7,000 job-years (0.09 percent) in the Inhofe case; 16,000 job-years (0.2 percent) in the Carper International case; 21,000 job-years (0.3 percent) in the Carper Domestic case; and 80,000 job-years (1.0 percent) in the Jeffords case.

In the Jeffords case, from 2009 through 2015, oil and gas wells, and therefore jobs, are notably higher than in the reference case in response to a relatively short surge in prices. The increase is greatest in 2010 at 30,000 jobs. The increased drilling activity allows for notably higher production levels in the 2011 to 2018 time frame. However, by 2017 and through the end of the forecast period, the number of oil and gas extraction jobs in the Jeffords case is lower than the reference case by at most 12,000 jobs due to alternative generation technologies, including renewables and nuclear, competing with natural gas for the generation market.

Though difficult to quantify, increased employment in the renewable fuels industry is expected to occur in response to policies to reduce power sector emissions of NO_x, SO_2, Hg, and, particularly, CO_2. In the Inhofe case, the change would likely be small because the increase in renewable generation relative to the reference case is not large. In the Carper and Jeffords cases the impacts would be larger. However, most renewables, including geothermal, hydroelectric, landfill gas, solar, and wind for example, are not supported by continuous renewable energy extraction industries which tend to be labor intensive. Only biomass involves notable labor in energy production, such as for energy crops or for separating, preparing, and transporting various agricultural and forest wastes. Also, employment declines at retiring coal plants will be at least partially offset by growing employment at the natural gas, renewable and, in the Jeffords case, nuclear plants that are added.

3. Data and Analysis Uncertainties

As with any long-term projection, there are considerable uncertainties. It is impossible to predict future fuel prices and 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 future natural gas prices and the availability and market acceptance of low- or zero-carbon generation technologies, including new nuclear, renewable, and fossil plants with carbon capture and sequestration equipment.

Another key uncertainty is the cost and performance of technologies designed to remove mercury. 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, they reach different conclusions. The understanding of what contributes to mercury emissions will likely improve in coming years as research efforts continue, but the outcome of these efforts is unknown.

One particular area of uncertainty with respect to mercury control concerns the role that NO_x control devices, or 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 Inhofe, Carper, and Jeffords 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 are only now being evaluated. This analysis assumes these systems will be equally effective on the lower-rank coals and be able to achieve removal rates up to 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. The cost and performance of mercury control systems are particularly important in the analysis of the Jeffords bill. As discussed, the Jeffords bill calls for facility-specific mercury reductions that generally require more than 90 percent of the mercury in the coal to be removed. It is unclear whether the technologies in development will be able to achieve removal rates this high for all plants and coal types.

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.[19] 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.[20] 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 opportunities for reducing greenhouse gas emissions, some actually with negative costs (i.e., a company could increase its profits by taking the actions).[21] 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.[22] 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

[19] Power Engineering, May 2003, *Uniqueness of SCR Retrofits Translates into Broad Cost Variations*.
[20] Ibid
[21] The negative cost options were set to $1 in this analysis.
[22] 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.

receive extra CO_2 allowances. However, in this case program regulators would never accurately know how much greenhouse gases were actually being reduced.

With respect to natural gas prices, one only has to look at their volatility in recent years to understand their uncertainty. Recent data appear to suggest declining well productivity, but it is unclear whether this will continue to be seen in the future or whether technological advances will moderate the recent price increases.

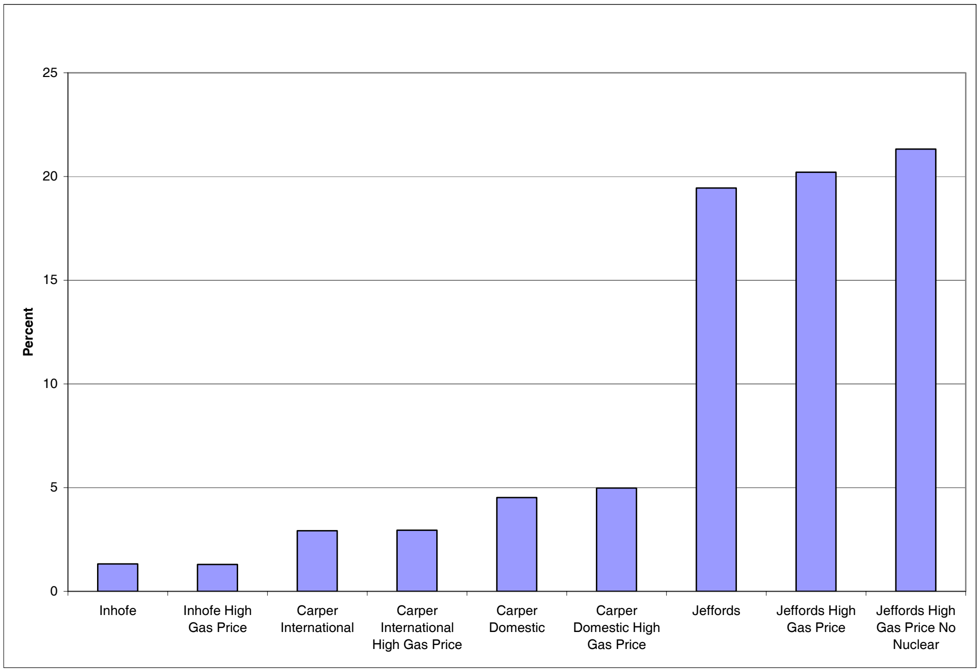
Sensitivity cases assuming slower rates of progress in oil and natural gas supply technologies were prepared to assess the sensitivity of the results to higher natural gas prices.[23] In addition, since it has been more than 25 years since a nuclear plant has been ordered, a Jeffords case with higher natural gas prices without new nuclear plants was also prepared. In a case without any of the proposed legislation, the slower technology progress rates resulted in a natural gas wellhead price of $4.99 per thousand cubic feet in 2025, $0.56 per thousand cubic feet higher than in the reference case.

The key results in these cases are that higher natural gas prices will increase the resource costs of complying with the three bill provisions and change the mix of generating capacity built to meet consumers' needs (Figure 38). The impact on resource costs is small in the Inhofe case because fuel switching was not a very important compliance option in that case. Higher natural gas prices have a bigger impact in the Carper Cases and Jeffords cases where fuel switching is more important. In the Carper Domestic High Gas Price case, higher natural gas prices lead to a 10 percent ($7 billion) increase in the discounted industry costs of compliance. In the Jeffords High Gas Price case, higher natural gas prices increase the discounted industry costs of compliance by 4 percent ($11 billion). In the Jeffords High Gas Price/No Nuclear case, the cost of compliance rises still further.

As might be expected, higher natural gas prices cause the industry to reduce its dependence on natural gas technologies and turn to increased use of coal, renewables, and, in the Jeffords cases, coal plants with carbon capture and sequestration equipment (Figure 39). In the reference and Inhofe cases, higher natural gas prices primarily lead to greater dependence on new coal plants. In the Carper cases, higher natural gas prices lead to increased dependence on new renewable and coal plants. In the Jeffords cases, higher natural gas prices lead to increased dependence on new coal plants with carbon capture and sequestration equipment, particularly when new nuclear plants can not be built.

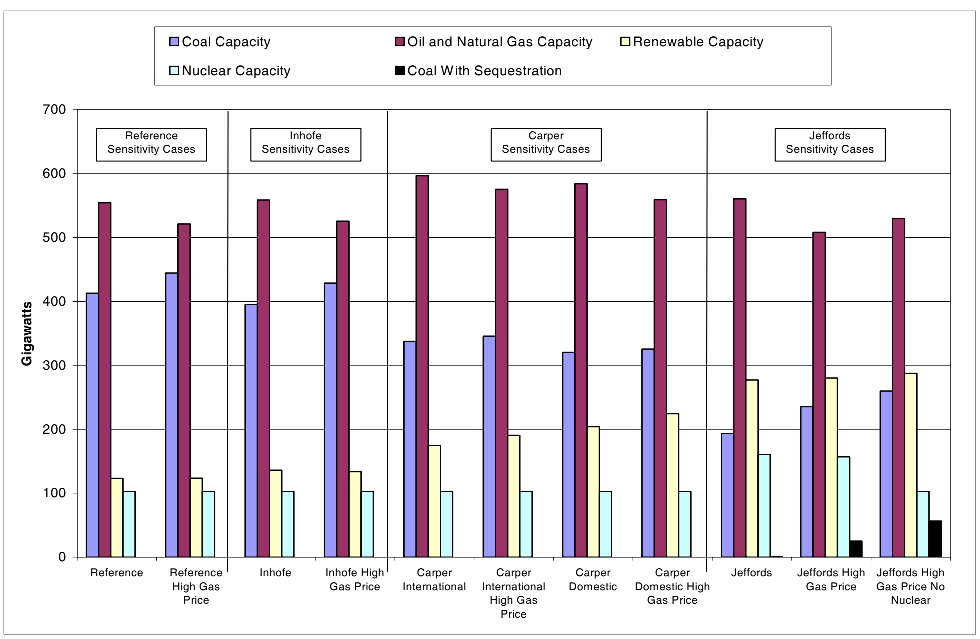
[23] For further discussion of the assumptions used from the slow oil and gas technology case see, the Energy Information Administration, *Annual Energy Outlook 2004*, DOE/EIA-0383(2004) (Washington, DC, January 2004), pages 254-255.

Figure 38. Percentage Change in Electricity Industry Costs in Alternative Cases, 2005 through 2025



Source: National Energy Modeling System, inbase.d040904a, inbaselt.d040904a, incs3pws.d040904a, incs3pwslt.d040904a, inca4p.d040904a, inca4plt.d040904a, inca4plo.d040904a, inca4plolt.d040904a, injf4p.d041604a, injf4plt.d041604a, and injf4pltnn.d041604b.

Figure 39. Capacity Mix in Alternative Cases, 2025



Source: National Energy Modeling System, inbase.d040904a, inbaselt.d040904a, incs3pws.d040904a, incs3pwslt.d040904a, inca4p.d040904a, inca4plt.d040904a, inca4plo.d040904a, inca4plolt.d040904a, injf4p.d041604a, injf4plt.d041604a, and injf4pltnn.d041604b.

Appendix A

Letter from Senator James M. Inhofe

United States Senate

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

March 1, 2004

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

Dear Mr. Administrator:

Air quality and its regulation is an important issue for the American public. Consequently, legislation affecting the regulation of environmental emissions from electric generators is of increasing interest to the Senate. Therefore, 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, S.366, Clean Power Act of 2003, introduced by Senator James Jeffords, and S.1844, Clear Skies Act of 2003, introduced by myself.

These bills would require significant reductions of emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and Mercury (Hg). In addition, the Clean Air Planning Act of 2003 and the Clean Power Act of 2003 requires reductions of carbon dioxide emissions (CO_2).

I am particularly interested that the following components be included in the analysis:
1. The reductions in SO_2, NOx, Hg, and CO_2 required both nationally and regionally;
2. The marginal cost of reducing SO_2, NOx, Hg, and CO_2 (provide regional information where appropriate);
3. The amount of emissions control equipment 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 gas, oil, renewable, etc.) and energy prices;
6. The impact on residential electric and natural gas consumers;
7. The impact on macroeconomic activity and national coal employment, resulting from passage of each Bill;
8. The change in electric industry revenues projected for each of the Bills.

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 detailed analysis by April 19th, 2004 to assist the Committee in preparation for hearings this Spring. Thank you in advance for your cooperation. This analysis will be essential to ensuring an informed debate on the multi-emission issue.

Sincerely,

James M. Inhofe

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

Appendix B

Comparison Tables for Reference, Clear Skies, and Jeffords Cases

Table B1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Production										
Crude Oil and Lease Condensate	11.91	12.61	12.60	12.61	10.52	10.53	10.55	9.81	9.82	9.83
Natural Gas Plant Liquids	2.56	3.19	3.19	3.17	3.44	3.46	3.46	3.44	3.47	3.49
Dry Natural Gas	19.56	21.76	21.76	21.59	24.20	24.42	24.42	24.38	24.64	24.85
Coal	22.70	25.11	24.90	17.00	27.88	27.05	15.82	30.88	29.72	15.81
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	9.72	8.61	8.61	13.17
Renewable Energy[1]	5.84	7.22	7.27	9.27	8.56	8.92	15.80	9.20	9.85	17.08
Other[2]	1.13	0.89	0.89	0.91	0.81	0.81	0.81	0.84	0.84	0.84
Total	**71.85**	**79.19**	**79.03**	**72.96**	**84.03**	**83.81**	**80.59**	**87.16**	**86.94**	**85.06**
Imports										
Crude Oil[3]	19.84	24.53	24.53	24.07	31.43	31.44	31.24	34.07	34.03	33.63
Petroleum Products[4]	4.76	5.69	5.59	5.29	8.25	8.08	7.52	10.10	9.94	9.53
Natural Gas	4.10	5.67	5.69	6.96	7.50	7.60	8.18	8.17	8.27	8.71
Other Imports[5]	0.52	0.95	0.96	0.44	1.12	1.12	0.27	1.18	1.18	0.16
Total	**29.22**	**36.84**	**36.78**	**36.76**	**48.30**	**48.25**	**47.20**	**53.52**	**53.42**	**52.03**
Exports										
Petroleum[6]	2.03	2.14	2.14	2.08	2.13	2.12	2.10	2.14	2.13	2.11
Natural Gas	0.52	0.81	0.81	0.79	0.80	0.79	0.73	0.72	0.70	0.62
Coal	1.03	0.89	0.89	0.90	0.69	0.69	0.61	0.58	0.55	0.52
Total	**3.58**	**3.85**	**3.85**	**3.77**	**3.61**	**3.60**	**3.44**	**3.44**	**3.39**	**3.25**
Discrepancy[7]	**-0.23**	**0.32**	**0.32**	**0.09**	**0.47**	**0.48**	**0.16**	**0.56**	**0.58**	**0.28**
Consumption										
Petroleum Products[8]	38.11	44.25	44.14	43.44	51.64	51.52	50.78	55.34	55.16	54.40
Natural Gas	23.37	26.78	26.80	27.93	31.09	31.41	32.04	32.02	32.40	33.13
Coal	22.18	25.08	24.88	16.55	28.27	27.44	15.69	31.49	30.35	15.73
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	9.72	8.61	8.61	13.17
Renewable Energy[1]	5.84	7.22	7.27	9.27	8.56	8.92	15.80	9.20	9.85	17.08
Other[9]	0.07	0.11	0.12	0.25	0.07	0.08	0.14	0.03	0.03	0.04
Total	**97.72**	**111.86**	**111.64**	**105.86**	**128.24**	**127.97**	**124.18**	**136.68**	**136.40**	**133.56**
Net Imports - Petroleum	**22.57**	**28.07**	**27.98**	**27.28**	**37.55**	**37.40**	**36.65**	**42.04**	**41.84**	**41.05**
Prices (2002 dollars per unit)										
World Oil Price (dollars per barrel)[10]	23.68	24.17	24.17	24.17	26.02	26.02	26.02	27.00	27.00	27.00
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	2.95	3.40	3.41	4.03	4.15	4.21	4.31	4.43	4.44	4.40
Coal Minemouth Price (dollars per ton)	17.90	16.71	16.86	19.05	16.51	16.15	16.47	16.58	16.23	15.03
Average Electricity Price (cents per kilowatthour)	7.2	6.7	6.8	9.8	6.8	7.1	8.9	6.9	7.1	8.7

[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.
[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 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2002 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B2. Energy Consumption by Sector and Source
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Energy Consumption										
Residential										
Distillate Fuel	0.89	0.93	0.93	0.93	0.85	0.85	0.85	0.80	0.81	0.81
Kerosene	0.07	0.11	0.11	0.11	0.10	0.10	0.10	0.09	0.09	0.09
Liquefied Petroleum Gas	0.53	0.56	0.56	0.56	0.62	0.62	0.62	0.64	0.64	0.64
Petroleum Subtotal	1.48	1.60	1.60	1.60	1.57	1.57	1.57	1.53	1.53	1.54
Natural Gas	5.06	5.70	5.70	5.58	6.13	6.12	6.13	6.30	6.30	6.34
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	0.40	0.40	0.40	0.41	0.41	0.41	0.40	0.40	0.41
Electricity	4.33	4.86	4.83	4.45	5.57	5.52	5.19	5.91	5.87	5.54
Delivered Energy	**11.28**	**12.58**	**12.55**	**12.05**	**13.68**	**13.63**	**13.31**	**14.16**	**14.12**	**13.83**
Electricity Related Losses	9.60	10.46	10.38	8.95	11.39	11.33	10.35	11.88	11.81	11.13
Total	**20.88**	**23.04**	**22.94**	**21.00**	**25.07**	**24.96**	**23.65**	**26.04**	**25.93**	**24.95**
Commercial										
Distillate Fuel	0.49	0.63	0.63	0.64	0.68	0.68	0.69	0.70	0.71	0.72
Residual Fuel	0.08	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Petroleum Subtotal	0.72	0.93	0.93	0.94	0.98	0.98	0.99	1.01	1.01	1.02
Natural Gas	3.21	3.55	3.55	3.47	3.94	3.93	4.16	4.14	4.14	4.52
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.12	5.04	5.01	4.69	6.23	6.17	5.74	6.83	6.76	6.27
Delivered Energy	**8.25**	**9.72**	**9.69**	**9.29**	**11.34**	**11.29**	**11.09**	**12.17**	**12.11**	**12.01**
Electricity Related Losses	9.15	10.84	10.78	9.44	12.75	12.66	11.46	13.71	13.61	12.61
Total	**17.40**	**20.56**	**20.47**	**18.73**	**24.09**	**23.95**	**22.55**	**25.89**	**25.72**	**24.62**
Industrial[4]										
Distillate Fuel	1.16	1.18	1.18	1.15	1.34	1.34	1.30	1.43	1.43	1.38
Liquefied Petroleum Gas	2.22	2.36	2.36	2.29	2.74	2.74	2.69	2.95	2.95	2.89
Petrochemical Feedstock	1.22	1.35	1.35	1.30	1.54	1.54	1.51	1.63	1.63	1.60
Residual Fuel	0.20	0.21	0.21	0.21	0.22	0.22	0.21	0.23	0.23	0.21
Motor Gasoline[2]	0.16	0.16	0.16	0.16	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.40	4.39	4.31	4.97	4.97	4.88	5.17	5.17	5.04
Petroleum Subtotal	9.00	9.65	9.64	9.41	10.99	10.99	10.77	11.60	11.59	11.31
Natural Gas	7.43	8.62	8.63	8.49	9.83	9.89	10.49	10.54	10.65	11.52
Lease and Plant Fuel[6]	1.35	1.34	1.34	1.33	1.52	1.53	1.53	1.54	1.55	1.56
Natural Gas Subtotal	8.78	9.96	9.97	9.81	11.35	11.42	12.01	12.08	12.20	13.09
Metallurgical Coal	0.62	0.65	0.65	0.64	0.53	0.53	0.51	0.47	0.47	0.46
Steam Coal	1.47	1.43	1.43	1.41	1.47	1.46	1.42	1.49	1.49	1.43
Net Coal Coke Imports	0.03	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Coal Subtotal	2.12	2.09	2.09	2.05	2.00	1.99	1.93	1.97	1.96	1.89
Renewable Energy[7]	1.66	2.00	2.00	1.95	2.48	2.48	2.47	2.70	2.70	2.69
Electricity	3.39	3.84	3.83	3.57	4.49	4.45	4.12	4.87	4.82	4.44
Delivered Energy	**24.94**	**27.54**	**27.52**	**26.79**	**31.31**	**31.34**	**31.30**	**33.22**	**33.28**	**33.41**
Electricity Related Losses	7.53	8.26	8.23	7.18	9.18	9.13	8.23	9.79	9.71	8.92
Total	**32.47**	**35.80**	**35.75**	**33.97**	**40.49**	**40.46**	**39.53**	**43.01**	**42.99**	**42.34**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Transportation										
Distillate Fuel[8]	5.12	6.43	6.43	6.22	8.03	8.03	7.87	8.94	8.93	8.77
Jet Fuel[9]	3.34	3.93	3.92	3.90	4.69	4.69	4.68	4.91	4.91	4.91
Motor Gasoline[2]	16.62	19.94	19.96	19.90	23.38	23.40	23.41	25.32	25.34	25.35
Residual Fuel	0.71	0.79	0.79	0.79	0.82	0.81	0.81	0.83	0.83	0.82
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.25	0.25	0.30	0.30	0.29	0.32	0.32	0.32
Petroleum Subtotal	26.06	31.41	31.42	31.12	37.30	37.31	37.14	40.40	40.41	40.25
Pipeline Fuel Natural Gas	0.65	0.72	0.72	0.72	0.85	0.86	0.88	0.86	0.87	0.91
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	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**26.79**	**32.27**	**32.29**	**31.98**	**38.36**	**38.38**	**38.23**	**41.50**	**41.52**	**41.40**
Electricity Related Losses	0.17	0.19	0.19	0.18	0.22	0.22	0.22	0.24	0.24	0.24
Total	**26.96**	**32.47**	**32.48**	**32.16**	**38.58**	**38.60**	**38.45**	**41.74**	**41.76**	**41.64**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.66	9.17	9.17	8.94	10.90	10.90	10.72	11.88	11.87	11.68
Kerosene	0.09	0.16	0.16	0.16	0.14	0.14	0.15	0.13	0.13	0.13
Jet Fuel[9]	3.34	3.93	3.92	3.90	4.69	4.69	4.68	4.91	4.91	4.91
Liquefied Petroleum Gas	2.86	3.07	3.07	3.00	3.54	3.54	3.49	3.77	3.77	3.72
Motor Gasoline[2]	16.83	20.15	20.17	20.10	23.61	23.63	23.64	25.56	25.58	25.59
Petrochemical Feedstock	1.22	1.35	1.35	1.30	1.54	1.54	1.51	1.63	1.63	1.60
Residual Fuel	1.00	1.13	1.13	1.13	1.17	1.17	1.15	1.19	1.19	1.17
Other Petroleum[12]	4.26	4.63	4.62	4.53	5.24	5.24	5.15	5.47	5.47	5.34
Petroleum Subtotal	37.26	43.59	43.59	43.07	50.84	50.85	50.48	54.54	54.55	54.13
Natural Gas	15.71	17.94	17.94	17.59	20.00	20.05	20.87	21.10	21.20	22.48
Lease and Plant Fuel Plant[6]	1.35	1.34	1.34	1.33	1.52	1.53	1.53	1.54	1.55	1.56
Pipeline Natural Gas	0.65	0.72	0.72	0.72	0.85	0.86	0.88	0.86	0.87	0.91
Natural Gas Subtotal	17.72	19.99	20.00	19.63	22.36	22.43	23.27	23.49	23.63	24.96
Metallurgical Coal	0.62	0.65	0.65	0.64	0.53	0.53	0.51	0.47	0.47	0.46
Steam Coal	1.58	1.54	1.54	1.52	1.58	1.57	1.53	1.60	1.59	1.54
Net Coal Coke Imports	0.03	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Coal Subtotal	2.23	2.20	2.20	2.16	2.11	2.10	2.04	2.08	2.07	2.00
Renewable Energy[13]	2.15	2.50	2.50	2.45	2.99	2.99	2.98	3.21	3.21	3.20
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.92	13.82	13.76	12.79	16.39	16.25	15.17	17.73	17.57	16.37
Delivered Energy	**71.27**	**82.11**	**82.05**	**80.11**	**94.69**	**94.63**	**93.93**	**101.06**	**101.03**	**100.65**
Electricity Related Losses	26.45	29.75	29.59	25.75	33.55	33.34	30.24	35.62	35.37	32.91
Total	**97.72**	**111.86**	**111.64**	**105.86**	**128.24**	**127.97**	**124.17**	**136.68**	**136.40**	**133.55**
Electric Power[14]										
Distillate Fuel	0.16	0.16	0.16	0.21	0.24	0.29	0.08	0.25	0.27	0.06
Residual Fuel	0.69	0.50	0.40	0.16	0.56	0.37	0.22	0.55	0.34	0.21
Petroleum Subtotal	0.85	0.66	0.55	0.37	0.80	0.66	0.30	0.80	0.61	0.27
Natural Gas	5.65	6.79	6.80	8.30	8.72	8.97	8.77	8.52	8.77	8.17
Steam Coal	19.96	22.88	22.68	14.39	26.16	25.34	13.65	29.41	28.28	13.74
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	9.72	8.61	8.61	13.17
Renewable Energy[15]	3.69	4.72	4.77	6.82	5.57	5.93	12.82	5.99	6.65	13.88
Electricity Imports	0.07	0.11	0.12	0.25	0.07	0.08	0.14	0.03	0.03	0.04
Total	**38.36**	**43.57**	**43.35**	**38.55**	**49.94**	**49.59**	**45.41**	**53.35**	**52.94**	**49.28**

Table B2. Energy Consumption by Sector and Source (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Total Energy Consumption										
Distillate Fuel	7.82	9.33	9.32	9.15	11.14	11.19	10.80	12.13	12.14	11.73
Kerosene	0.09	0.16	0.16	0.16	0.14	0.14	0.15	0.13	0.13	0.13
Jet Fuel[9]	3.34	3.93	3.92	3.90	4.69	4.69	4.68	4.91	4.91	4.91
Liquefied Petroleum Gas	2.86	3.07	3.07	3.00	3.54	3.54	3.49	3.77	3.77	3.72
Motor Gasoline[2]	16.83	20.15	20.17	20.10	23.61	23.63	23.64	25.56	25.58	25.59
Petrochemical Feedstock	1.22	1.35	1.35	1.30	1.54	1.54	1.51	1.63	1.63	1.60
Residual Fuel	1.69	1.64	1.53	1.29	1.73	1.54	1.38	1.73	1.52	1.38
Other Petroleum[12]	4.26	4.63	4.62	4.53	5.24	5.24	5.15	5.47	5.47	5.34
Petroleum Subtotal	38.11	44.25	44.14	43.44	51.64	51.52	50.78	55.34	55.16	54.40
Natural Gas	21.36	24.73	24.74	25.88	28.72	29.02	29.64	29.63	29.98	30.66
Lease and Plant Fuel[6]	1.35	1.34	1.34	1.33	1.52	1.53	1.53	1.54	1.55	1.56
Pipeline Natural Gas	0.65	0.72	0.72	0.72	0.85	0.86	0.88	0.86	0.87	0.91
Natural Gas Subtotal	23.37	26.78	26.80	27.93	31.09	31.41	32.04	32.02	32.40	33.13
Metallurgical Coal	0.62	0.65	0.65	0.64	0.53	0.53	0.51	0.47	0.47	0.46
Steam Coal	21.54	24.42	24.22	15.91	27.74	26.91	15.18	31.01	29.88	15.27
Net Coal Coke Imports	0.03	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Coal Subtotal	22.18	25.08	24.88	16.55	28.27	27.44	15.69	31.49	30.35	15.73
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	9.72	8.61	8.61	13.17
Renewable Energy[16]	5.84	7.22	7.27	9.27	8.56	8.92	15.80	9.20	9.85	17.08
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.07	0.11	0.12	0.25	0.07	0.08	0.14	0.03	0.03	0.04
Total	**97.72**	**111.86**	**111.64**	**105.86**	**128.24**	**127.97**	**124.18**	**136.68**	**136.40**	**133.56**
Energy Use and Related Statistics										
Delivered Energy Use	71.27	82.11	82.05	80.11	94.69	94.63	93.93	101.06	101.03	100.65
Total Energy Use	97.72	111.86	111.64	105.86	128.24	127.97	124.17	136.68	136.40	133.55
Population (millions)	288.93	309.28	309.28	309.28	334.61	334.61	334.61	347.53	347.53	347.53
Gross Domestic Product (billion 1996 dollars)	9440	12198	12191	12013	16194	16192	16176	18523	18519	18510
Carbon Dioxide Emissions (million metric tons)	5729.4	6550.5	6524.3	5752.9	7545.1	7473.9	6344.5	8133.4	8032.2	6638.2

[1]Includes wood used for residential heating.
[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.
[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 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 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: 2002 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 population and gross domestic product: Global Insight macroeconomic model T250803. 2002 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B3. Energy Prices by Sector and Source
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Residential	**14.73**	**14.18**	**14.40**	**18.17**	**14.94**	**15.24**	**17.46**	**15.27**	**15.55**	**17.48**
Primary Energy[1]	8.14	8.14	8.14	8.62	8.64	8.68	8.79	8.90	8.91	8.89
Petroleum Products[2]	9.87	9.89	9.88	9.87	10.86	10.86	10.83	11.27	11.27	11.26
Distillate Fuel	8.23	7.82	7.81	7.81	8.37	8.38	8.33	8.54	8.53	8.53
Liquefied Petroleum Gas	12.92	13.86	13.84	13.80	14.82	14.81	14.80	15.20	15.19	15.16
Natural Gas	7.64	7.66	7.67	8.27	8.09	8.14	8.28	8.33	8.35	8.32
Electricity	24.73	23.28	23.89	33.62	23.66	24.39	30.33	23.72	24.43	29.72
Commercial	**14.70**	**13.79**	**14.05**	**18.71**	**14.87**	**15.23**	**17.66**	**15.21**	**15.54**	**17.49**
Primary Energy[1]	6.38	6.46	6.47	6.93	6.99	7.03	7.10	7.23	7.24	7.21
Petroleum Products[2]	6.88	6.33	6.32	6.29	6.81	6.81	6.75	6.98	6.97	6.95
Distillate Fuel	6.07	5.45	5.45	5.44	5.99	6.00	5.93	6.15	6.15	6.15
Residual Fuel	4.21	4.13	4.11	4.07	4.41	4.38	4.34	4.55	4.52	4.49
Natural Gas	6.40	6.63	6.64	7.24	7.17	7.22	7.32	7.42	7.44	7.39
Electricity	22.83	20.46	20.98	30.02	21.22	21.90	27.30	21.35	21.99	26.73
Industrial[3]	**6.31**	**6.45**	**6.51**	**9.28**	**7.18**	**7.27**	**9.10**	**7.42**	**7.49**	**9.14**
Primary Energy	4.77	5.13	5.13	7.21	5.83	5.86	7.39	6.08	6.07	7.49
Petroleum Products[2]	6.35	6.83	6.82	8.39	7.56	7.56	8.90	7.79	7.78	9.08
Distillate Fuel	6.21	5.68	5.67	8.20	6.24	6.24	8.39	6.40	6.40	8.53
Liquefied Petroleum Gas	8.28	9.68	9.66	11.83	10.67	10.66	12.60	11.10	11.03	12.86
Residual Fuel	3.89	3.74	3.73	6.45	4.03	4.00	6.40	4.17	4.15	6.43
Natural Gas[4]	3.75	4.06	4.08	6.43	4.76	4.82	6.39	5.03	5.05	6.46
Metallurgical Coal	1.87	1.96	1.96	5.30	1.84	1.84	4.76	1.77	1.77	4.54
Steam Coal	1.48	1.57	1.58	4.94	1.54	1.52	4.32	1.52	1.50	4.10
Electricity	14.74	13.42	13.83	20.83	14.01	14.54	18.73	14.04	14.57	18.37
Transportation	**9.91**	**10.52**	**10.51**	**10.50**	**10.58**	**10.59**	**10.56**	**10.74**	**10.74**	**10.75**
Primary Energy	9.88	10.49	10.49	10.45	10.55	10.56	10.51	10.72	10.72	10.71
Petroleum Products[2]	9.88	10.49	10.49	10.46	10.56	10.56	10.52	10.72	10.72	10.72
Distillate Fuel[5]	9.41	10.16	10.13	10.11	10.09	10.10	9.96	10.12	10.13	10.13
Jet Fuel[6]	5.97	5.76	5.76	5.75	6.09	6.09	5.99	6.31	6.29	6.30
Motor Gasoline[7]	11.15	11.88	11.88	11.83	11.90	11.91	11.90	12.06	12.06	12.05
Residual Fuel	3.77	3.60	3.59	3.58	3.87	3.87	3.86	4.02	4.01	4.00
Liquefied Petroleum Gas[8]	15.00	14.94	14.92	14.84	15.55	15.53	15.51	15.84	15.83	15.76
Natural Gas[9]	7.38	8.24	8.25	8.84	8.91	8.97	9.05	9.11	9.12	9.08
Ethanol (E85)[10]	15.19	17.21	17.22	17.96	18.24	18.27	18.73	18.66	18.68	18.98
Electricity	20.89	19.62	20.09	28.16	20.05	20.66	25.41	19.88	20.47	24.76
Average End-Use Energy	**10.10**	**10.23**	**10.31**	**12.30**	**10.73**	**10.84**	**12.00**	**10.95**	**11.05**	**12.05**
Primary Energy	7.70	8.22	8.22	8.96	8.63	8.65	9.10	8.86	8.86	9.26
Electricity	21.21	19.49	20.01	28.69	20.07	20.72	25.99	20.12	20.76	25.46
Electric Power[11]										
Fossil Fuel Average	1.89	1.92	1.95	5.43	2.15	2.22	5.05	2.13	2.19	4.90
Petroleum Products	4.33	4.21	4.30	7.30	4.66	4.89	7.23	4.85	5.10	7.33
Distillate Fuel	5.58	4.91	4.91	7.39	5.46	5.45	7.70	5.63	5.62	7.85
Residual Fuel	4.04	3.99	4.06	7.17	4.32	4.45	7.07	4.50	4.68	7.19
Natural Gas	3.77	4.08	4.09	6.74	4.75	4.84	6.58	4.99	5.04	6.62
Steam Coal	1.25	1.22	1.26	4.62	1.21	1.22	4.02	1.22	1.24	3.83

Table B3. Energy Prices by Sector and Source (Continued)
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Average Price to All Users[12]										
Petroleum Products[2]	8.94	9.58	9.58	9.95	9.84	9.87	10.17	10.04	10.06	10.38
Distillate Fuel	8.52	8.95	8.93	9.25	9.15	9.14	9.37	9.26	9.25	9.58
Jet Fuel	5.97	5.76	5.76	5.75	6.09	6.09	5.99	6.31	6.29	6.30
Liquefied Petroleum Gas	9.27	10.61	10.59	12.26	11.56	11.56	13.06	11.96	11.90	13.33
Motor Gasoline[7]	11.15	11.88	11.88	11.85	11.90	11.91	11.91	12.06	12.06	12.07
Residual Fuel	3.92	3.78	3.78	4.54	4.08	4.07	4.82	4.23	4.23	4.92
Natural Gas	5.08	5.27	5.29	7.04	5.81	5.86	6.98	6.07	6.08	7.03
Coal	1.27	1.24	1.28	4.63	1.23	1.24	4.03	1.24	1.25	3.84
Ethanol (E85)[10]	15.19	17.21	17.22	17.96	18.24	18.27	18.73	18.66	18.68	18.98
Electricity	21.21	19.49	20.01	28.69	20.07	20.72	25.99	20.12	20.76	25.46
Non-Renewable Energy Expenditures by Sector (billion 2002 dollars)										
Residential	160.36	172.65	174.96	211.52	198.31	201.58	225.15	210.08	213.26	234.60
Commercial	119.80	132.62	134.80	171.98	167.25	170.43	194.10	183.65	186.67	208.33
Industrial	120.90	133.42	134.82	189.45	168.58	171.16	215.60	185.98	188.28	232.48
Transportation	259.09	331.86	331.88	328.42	396.83	397.23	394.30	436.57	436.66	435.37
Total Non-Renewable Expenditures	660.15	770.54	776.45	901.36	930.96	940.40	1029.15	1016.28	1024.88	1110.78
Transportation Renewable Expenditures	0.01	0.03	0.03	0.03	0.06	0.06	0.06	0.07	0.07	0.07
Total Expenditures	**660.16**	**770.58**	**776.48**	**901.40**	**931.02**	**940.46**	**1029.21**	**1016.35**	**1024.95**	**1110.85**

[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 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 electric power sector natural gas prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998.* 2002 coal prices based on EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run INBASE.D040904A. 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B4. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1875	2181	2157	1410	2556	2443	1313	2954	2808	1316
Petroleum	77	62	52	36	76	65	27	76	59	24
Natural Gas[3]	450	643	645	884	957	997	977	966	1010	877
Nuclear Power	780	806	806	806	824	824	931	824	824	1261
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources[4]	304	404	409	581	449	481	1129	471	531	1241
Distributed Generation (Natural Gas)	0	0	0	2	4	4	52	6	6	87
Non-Utility Generation for Own Use	-34	-37	-37	-41	-37	-37	-40	-37	-37	-40
Total	**3443**	**4050**	**4022**	**3669**	**4820**	**4767**	**4379**	**5250**	**5191**	**4756**
Combined Heat and Power[5]										
Coal	32	34	33	15	34	33	26	33	33	26
Petroleum	6	1	1	3	2	2	2	2	2	1
Natural Gas	148	176	179	198	163	166	153	148	147	138
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-11	-24	-24	-25	-24	-24	-24	-24	-24	-24
Total	**183**	**190**	**192**	**196**	**179**	**181**	**161**	**164**	**162**	**146**
Net Available to the Grid	**3626**	**4240**	**4215**	**3865**	**4999**	**4948**	**4540**	**5414**	**5353**	**4901**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	21	21	21	21	21	21	21	21	21	21
Petroleum	5	12	12	15	18	19	20	19	19	21
Natural Gas	84	105	107	124	146	159	285	174	193	380
Other Gaseous Fuels[7]	5	9	9	9	12	12	10	13	13	11
Renewable Sources[4]	30	39	39	37	50	50	49	54	54	54
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**157**	**197**	**200**	**218**	**259**	**272**	**397**	**292**	**312**	**497**
Other End-Use Generators[9]	4	5	5	5	6	6	8	7	8	11
Generation for Own Use	-134	-156	-157	-166	-187	-194	-267	-207	-218	-328
Total Sales to the Grid	**27**	**46**	**47**	**57**	**77**	**84**	**138**	**91**	**102**	**181**
Total Electricity Generation	**3831**	**4504**	**4481**	**4153**	**5325**	**5287**	**5010**	**5774**	**5734**	**5474**
Net Imports	**22**	**32**	**36**	**74**	**21**	**23**	**42**	**7**	**9**	**13**
Electricity Sales by Sector										
Residential	1268	1424	1415	1303	1631	1618	1520	1733	1720	1622
Commercial	1208	1476	1469	1375	1825	1809	1684	2000	1981	1839
Industrial	994	1125	1122	1045	1315	1304	1209	1428	1414	1301
Transportation	22	26	26	26	32	32	32	35	35	35
Total	**3492**	**4051**	**4033**	**3750**	**4803**	**4764**	**4445**	**5196**	**5150**	**4798**
End-Use Prices[10] (2002 cents per kilowatthour)										
Residential	8.4	7.9	8.2	11.5	8.1	8.3	10.3	8.1	8.3	10.1
Commercial	7.8	7.0	7.2	10.2	7.2	7.5	9.3	7.3	7.5	9.1
Industrial	5.0	4.6	4.7	7.1	4.8	5.0	6.4	4.8	5.0	6.3
Transportation	7.1	6.7	6.9	9.6	6.8	7.1	8.7	6.8	7.0	8.4
All Sectors Average	**7.2**	**6.7**	**6.8**	**9.8**	**6.8**	**7.1**	**8.9**	**6.9**	**7.1**	**8.7**
Prices by Service Category[10] (2002 cents per kilowatthour)										
Generation	4.6	4.1	4.3	7.1	4.5	4.7	6.4	4.5	4.7	6.3
Transmission	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	1.9	1.9	2.0	1.8	1.8	1.8	1.7	1.7	1.7

Table B4. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Electric Power Sector Emissions[1]										
Sulfur Dioxide (million tons)	10.19	9.62	6.18	3.63	8.95	4.18	1.25	8.95	3.62	1.18
Nitrogen Oxide (million tons)	4.39	3.48	2.19	1.50	3.66	1.79	0.61	3.72	1.79	0.61
Mercury (tons)	50.81	52.60	39.55	3.97	53.50	28.87	3.70	54.60	29.01	3.73

[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 2002 are model results and may differ slightly from official EIA data reports.
Source: 2002 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, October 2002), and supporting databases. 2002 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2002 prices: EIA, National Energy Modeling System run INBASE.D040904A. **Projections**: EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Electric PowerSector[2]										
Power Only[3]										
Coal Steam	305.7	302.4	302.6	292.3	348.0	336.2	185.9	403.6	386.5	185.7
Other Fossil Steam[4]	132.5	102.2	100.2	113.6	97.5	94.3	87.1	95.5	92.1	84.0
Combined Cycle	81.0	126.6	126.9	149.8	180.0	185.1	195.8	200.7	208.0	201.4
Combustion Turbine/Diesel	122.7	130.4	127.8	136.4	162.2	161.9	147.9	176.1	174.6	158.0
Nuclear Power[5]	98.7	100.6	100.6	100.6	102.6	102.6	117.2	102.6	102.6	160.9
Pumped Storage	20.2	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	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	91.4	98.1	97.9	146.7	107.1	112.9	250.2	112.3	124.9	264.1
Distributed Generation[7]	0.0	0.5	0.5	0.6	8.4	8.4	12.0	13.8	13.1	19.9
Total	**852.3**	**881.2**	**876.8**	**960.5**	**1026.3**	**1021.9**	**1016.7**	**1124.9**	**1122.0**	**1094.3**
Combined Heat and Power[8]										
Coal Steam	5.2	5.2	4.7	4.7	5.2	4.7	3.7	5.2	4.7	3.7
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	29.4	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**41.4**	**44.9**	**44.4**	**44.4**	**44.9**	**44.4**	**43.4**	**44.9**	**44.4**	**43.4**
Total Electric Power Industry	**893.7**	**926.1**	**921.2**	**1004.8**	**1071.1**	**1066.3**	**1060.1**	**1169.8**	**1166.4**	**1137.8**
Cumulative Planned Additions[9]										
Coal Steam	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
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	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5
Combustion Turbine/Diesel	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	0.0	4.3	4.3	4.3	4.7	4.7	4.7	4.8	4.8	4.8
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**	**57.1**	**57.1**	**57.1**	**57.5**	**57.5**	**57.5**	**57.6**	**57.6**	**57.6**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	2.9	3.5	0.2	50.4	39.1	1.7	107.1	90.4	1.9
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	6.7	7.0	29.4	60.0	65.2	77.0	80.8	88.1	82.6
Combustion Turbine/Diesel	0.0	10.7	8.5	14.4	43.8	45.2	33.0	61.6	60.8	43.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	14.6	0.0	0.0	58.3
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	2.1	1.9	50.7	10.7	16.5	153.8	15.7	28.3	167.6
Distributed Generation[7]	0.0	0.5	0.5	0.6	8.4	8.4	12.0	13.8	13.1	19.9
Total	**0.0**	**22.9**	**21.3**	**95.3**	**173.4**	**174.4**	**292.3**	**279.0**	**280.6**	**373.4**
Cumulative Total Additions	**0.0**	**80.0**	**78.4**	**152.3**	**230.9**	**231.9**	**349.8**	**336.6**	**338.2**	**431.0**
Cumulative Retirements[10]										
Coal Steam	0.0	7.4	8.2	15.3	9.2	10.2	124.1	10.4	11.3	124.5
Other Fossil Steam[4]	0.0	28.4	30.4	17.0	33.1	36.3	43.5	35.1	38.5	46.6
Combined Cycle	0.0	1.7	1.7	1.1	1.7	1.7	2.8	1.7	1.7	2.8
Combustion Turbine/Diesel	0.0	10.3	10.8	10.6	11.6	13.3	17.7	15.6	16.2	17.7
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**47.9**	**51.2**	**44.1**	**55.8**	**61.6**	**188.3**	**62.9**	**67.9**	**191.8**

Table B5. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.2	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Petroleum	1.0	1.6	1.6	2.0	2.3	2.4	2.5	2.4	2.5	2.6
Natural Gas	14.1	17.1	17.5	19.8	22.7	24.4	42.0	26.4	29.1	55.1
Other Gaseous Fuels	1.8	2.2	2.2	2.2	2.5	2.6	2.3	2.7	2.7	2.4
Renewable Sources[6]	4.2	5.6	5.6	5.4	7.5	7.5	7.4	8.3	8.3	8.2
Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**25.5**	**31.0**	**31.4**	**33.8**	**39.6**	**41.3**	**58.7**	**44.2**	**47.0**	**72.8**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.4	1.4	1.5	1.9	1.9	3.1	2.5	2.6	4.5
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	5.5	5.9	8.3	14.1	15.9	33.2	18.7	21.5	47.3
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.8	0.9	2.1	1.5	1.6	3.4

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.9 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak-load capacity fueled by natural gas
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2002.
[10]Cumulative total retirements after December 31, 2002.
[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 B10 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model estimates and may differ slightly from official EIA data reports.
Source: 2002 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B6. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Production										
Dry Gas Production[1]	19.05	21.19	21.19	21.03	23.56	23.78	23.77	23.74	24.00	24.19
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	**3.49**	**4.74**	**4.76**	**6.03**	**6.55**	**6.65**	**7.27**	**7.28**	**7.39**	**7.90**
Canada	3.59	2.86	2.87	2.79	2.68	2.71	2.93	2.80	2.84	2.93
Mexico	-0.26	-0.30	-0.29	-0.27	-0.09	-0.09	-0.03	-0.02	0.00	0.08
Liquefied Natural Gas	0.17	2.17	2.18	3.50	3.96	4.03	4.38	4.50	4.56	4.90
Total Supply	**22.62**	**26.02**	**26.04**	**27.15**	**30.21**	**30.53**	**31.14**	**31.11**	**31.49**	**32.19**
Consumption by Sector										
Residential	4.92	5.55	5.55	5.43	5.96	5.96	5.96	6.13	6.13	6.16
Commercial	3.12	3.46	3.46	3.37	3.83	3.83	4.04	4.03	4.03	4.39
Industrial[3]	7.23	8.39	8.40	8.26	9.56	9.62	10.20	10.26	10.36	11.21
Electric Power[4]	5.55	6.66	6.67	8.14	8.56	8.81	8.61	8.36	8.61	8.02
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.63	0.70	0.70	0.70	0.82	0.84	0.86	0.84	0.85	0.88
Lease and Plant Fuel[6]	1.32	1.30	1.30	1.29	1.48	1.49	1.48	1.50	1.51	1.52
Total	**22.78**	**26.11**	**26.13**	**27.24**	**30.32**	**30.63**	**31.25**	**31.23**	**31.60**	**32.30**
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]	**-0.16**	**-0.09**	**-0.09**	**-0.09**	**-0.11**	**-0.11**	**-0.11**	**-0.11**	**-0.11**	**-0.11**

[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, 2002 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B7. Oil and Gas Supply

Production and Supply	2002	2010 Reference	2010 Inhofe	2010 Jeffords	2020 Reference	2020 Inhofe	2020 Jeffords	2025 Reference	2025 Inhofe	2025 Jeffords
		Projections								
Crude Oil										
Lower 48 Average Wellhead Price[1]										
(2002 dollars per barrel)	**24.54**	**23.64**	**23.64**	**23.63**	**25.61**	**25.61**	**25.63**	**26.86**	**26.86**	**26.91**
Production (million barrels per day)[2]										
U.S. Total	**5.62**	**5.96**	**5.95**	**5.95**	**4.97**	**4.98**	**4.99**	**4.63**	**4.64**	**4.64**
Lower 48 Onshore	3.11	2.61	2.61	2.61	2.20	2.20	2.20	2.04	2.04	2.05
Lower 48 Offshore	1.53	2.43	2.42	2.42	2.03	2.04	2.04	2.08	2.08	2.08
Alaska	0.98	0.92	0.92	0.92	0.74	0.74	0.74	0.51	0.51	0.51
Lower 48 End of Year Reserves (billion barrels)[2]	**19.05**	**18.42**	**18.41**	**18.43**	**16.17**	**16.19**	**16.11**	**15.04**	**15.06**	**15.06**
Natural Gas										
Lower 48 Average Wellhead Price[1]										
(2002 dollars per thousand cubic feet)	**2.95**	**3.40**	**3.41**	**4.03**	**4.15**	**4.21**	**4.31**	**4.43**	**4.44**	**4.40**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.05**	**21.19**	**21.19**	**21.03**	**23.57**	**23.78**	**23.78**	**23.74**	**24.00**	**24.19**
Lower 48 Onshore	13.76	15.13	15.14	15.15	16.33	16.52	16.62	16.47	16.53	16.63
Associated-Dissolved[4]	1.60	1.41	1.41	1.41	1.23	1.23	1.23	1.17	1.17	1.17
Non-Associated	12.16	13.72	13.73	13.74	15.10	15.29	15.39	15.31	15.36	15.46
Conventional	6.14	5.94	5.95	6.07	6.07	6.12	6.22	5.92	5.94	5.92
Unconventional	6.02	7.78	7.78	7.67	9.02	9.17	9.17	9.38	9.41	9.54
Lower 48 Offshore	4.86	5.62	5.61	5.44	5.14	5.16	5.06	5.15	5.18	5.10
Associated-Dissolved[4]	1.05	1.64	1.64	1.64	1.34	1.34	1.33	1.43	1.43	1.45
Non-Associated	3.81	3.98	3.97	3.80	3.80	3.82	3.74	3.72	3.75	3.65
Alaska	0.43	0.45	0.45	0.44	2.10	2.10	2.09	2.12	2.29	2.47
Lower 48 End of Year Dry Reserves[3]										
(trillion cubic feet)	**180.03**	**201.99**	**201.90**	**205.85**	**198.74**	**198.24**	**201.11**	**191.26**	**190.34**	**192.54**
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)	**24.47**	**25.36**	**25.39**	**28.80**	**26.64**	**26.72**	**26.37**	**26.09**	**26.11**	**25.80**

[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 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). 2002 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B8. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Production[1]										
Appalachia	408	404	387	270	406	391	243	418	403	230
Interior	147	166	151	97	171	120	107	177	134	91
West	550	655	676	439	796	812	399	937	931	439
East of the Mississippi	504	517	488	351	528	491	335	546	511	302
West of the Mississippi	601	708	726	456	845	833	415	987	956	459
Total	**1105**	**1225**	**1214**	**807**	**1373**	**1324**	**750**	**1532**	**1467**	**761**
Net Imports										
Imports	17	33	33	8	42	42	5	46	46	5
Exports	40	35	35	35	27	27	24	24	22	21
Total	**-23**	**-2**	**-2**	**-28**	**14**	**14**	**-19**	**22**	**23**	**-16**
Total Supply[2]	**1083**	**1223**	**1212**	**779**	**1387**	**1338**	**730**	**1554**	**1491**	**745**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	66	66	65	68	67	65	69	68	66
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	23	24	24	23	19	19	19	17	17	17
Electric Power[4]	976	1129	1118	698	1296	1247	658	1464	1401	673
Total	**1066**	**1223**	**1213**	**791**	**1388**	**1339**	**747**	**1555**	**1491**	**760**
Discrepancy and Stock Change[5]	**17**	**-0**	**-0**	**-12**	**-1**	**-1**	**-16**	**-1**	**-1**	**-15**
Average Minemouth Price										
(2002 dollars per short ton)	17.90	16.71	16.86	19.05	16.51	16.15	16.47	16.58	16.23	15.03
(2002 dollars per million Btu)	0.87	0.82	0.82	0.90	0.81	0.79	0.78	0.82	0.80	0.72
Delivered Prices (2002 dollars per short ton)[6]										
Industrial	32.39	34.11	34.28	107.31	33.45	32.97	93.74	33.09	32.55	89.14
Coke Plants	51.27	53.70	53.88	145.31	50.45	50.58	130.54	48.44	48.55	124.56
Electric Power										
(2002 dollars per short ton)	25.88	24.55	25.30	95.17	24.16	24.61	83.39	24.33	24.83	78.19
(2002 dollars per million Btu)	1.25	1.22	1.26	4.62	1.21	1.22	4.02	1.22	1.24	3.83
Average	**26.80**	**25.63**	**26.35**	**97.67**	**24.98**	**25.41**	**85.50**	**24.98**	**25.46**	**80.18**
Exports[7]	40.44	36.44	36.42	37.95	34.13	34.23	34.81	32.23	32.33	32.57

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003); EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003); and EIA, AEO2004 National Energy Modeling System run INBASE.D040904A. **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Table B9. Coal Production by Region and Type
(Million Short Tons)

Supply Regions and Coal Types	2002	Projections 2010 Reference	2010 Inhofe	2010 Jeffords	2020 Reference	2020 Inhofe	2020 Jeffords	2025 Reference	2025 Inhofe	2025 Jeffords
Northern Appalachia	**139.9**	**173.6**	**169.2**	**106.9**	**186.2**	**173.1**	**126.7**	**202.1**	**185.3**	**122.1**
Medium Sulfur (Premium)[1]	2.8	3.1	3.1	3.1	2.8	2.8	2.8	2.8	2.8	2.8
Low Sulfur (Bituminous)[2]	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.0	0.7	0.0
Medium Sulfur (Bituminous)[2]	66.6	86.4	78.4	37.9	86.9	83.4	54.0	92.1	90.0	53.0
High Sulfur (Bituminous)	59.4	75.7	81.6	65.8	88.1	80.4	67.8	98.4	85.4	64.1
High Sulfur (Gob)[3]	11.1	8.5	6.0	0.1	8.5	5.8	2.1	8.8	6.4	2.2
Central Appalachia	**249.1**	**218.8**	**204.4**	**152.8**	**208.8**	**207.3**	**109.2**	**206.1**	**206.8**	**101.4**
Medium Sulfur (Premium)[1]	34.0	34.5	34.5	34.4	29.1	29.1	28.0	23.6	23.4	23.0
Low Sulfur (Bituminous)	63.9	51.4	64.9	62.2	53.7	51.9	22.0	52.3	55.4	19.8
Medium Sulfur (Bituminous)	151.2	132.8	105.0	56.2	126.0	126.3	59.2	130.2	128.1	58.7
Southern Appalachia	**19.1**	**11.9**	**13.6**	**10.4**	**11.0**	**10.7**	**7.2**	**9.8**	**10.9**	**6.6**
Low Sulfur (Premium)[1]	4.6	4.8	4.8	4.9	1.1	1.1	1.0	1.0	0.9	0.9
Low Sulfur (Bituminous)	3.1	0.7	2.3	2.6	2.0	2.1	1.6	1.8	2.2	1.6
Medium Sulfur (Bituminous)	11.4	6.5	6.5	2.9	7.9	7.6	4.5	7.1	7.7	4.0
Eastern Interior	**96.0**	**113.1**	**101.0**	**80.6**	**121.9**	**99.5**	**91.9**	**127.7**	**107.8**	**71.6**
Medium Sulfur (Bituminous)	33.0	35.1	33.4	27.9	37.3	36.9	28.0	39.7	38.3	10.9
High Sulfur (Bituminous)	60.7	74.3	67.1	52.7	80.7	60.2	63.9	88.1	66.9	60.7
Medium Sulfur (Lignite)	2.3	3.8	0.4	0.0	3.9	2.4	0.0	0.0	2.7	0.0
Western Interior High Sulfur (Bituminous)	**1.9**	**1.7**	**1.6**	**0.3**	**1.5**	**1.3**	**1.5**	**1.9**	**0.5**	**1.1**
Gulf	**49.0**	**50.7**	**48.3**	**16.5**	**47.9**	**19.6**	**13.9**	**47.3**	**25.4**	**18.6**
Medium Sulfur (Lignite)	26.7	18.3	20.3	3.3	16.5	8.2	0.2	17.9	12.9	2.3
High Sulfur (Lignite)	22.3	32.4	28.1	13.1	31.4	11.4	13.7	29.5	12.5	16.3
Dakota Medium Sulfur (Lignite)	**31.1**	**32.9**	**29.4**	**23.8**	**30.3**	**31.7**	**26.3**	**32.9**	**32.9**	**25.0**
Powder/Green River	**410.2**	**512.7**	**520.8**	**305.2**	**628.1**	**627.0**	**263.9**	**751.5**	**728.9**	**298.4**
Low Sulfur (Bituminous)	0.0	1.0	1.0	0.9	1.1	1.1	0.2	0.0	0.3	0.2
Low Sulfur (Sub-Bituminous)	372.1	464.9	490.7	281.3	581.1	579.9	245.7	691.7	677.4	275.3
Medium Sulfur (Sub-Bituminous)	38.2	46.7	29.1	22.9	46.0	46.0	18.0	59.8	51.3	22.9
Rocky Mountain	**60.4**	**62.4**	**78.7**	**73.0**	**90.3**	**103.7**	**81.9**	**102.6**	**117.3**	**87.5**
Low Sulfur (Bituminous)	50.4	54.2	67.8	63.7	78.8	91.1	76.5	91.1	105.6	81.4
Low Sulfur (Sub-Bituminous)	10.0	8.2	10.9	9.2	11.6	12.6	5.4	11.5	11.7	6.0
Arizona/New Mexico	**41.7**	**41.8**	**41.7**	**35.7**	**41.6**	**44.3**	**25.3**	**44.9**	**46.0**	**24.7**
Low Sulfur (Bituminous)	23.0	22.7	23.3	24.1	17.8	24.9	13.6	21.5	24.6	13.4
Medium Sulfur (Bituminous)	1.8	8.3	8.3	3.5	9.8	9.8	2.0	9.4	9.5	1.9
Medium Sulfur (Sub-bituminous)	17.0	10.9	10.0	8.2	13.9	9.6	9.7	13.9	11.9	9.4
Washington/Alaska Medium Sulfur (Sub-Bituminous)	**7.0**	**5.3**	**5.3**	**1.6**	**5.4**	**5.4**	**1.7**	**5.4**	**5.4**	**3.8**

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

Supply Regions and Coal Types	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Subtotals: All Regions										
Premium Metallurgical[1]	41.4	42.4	42.4	42.3	33.0	33.0	31.8	27.3	27.1	26.7
Bituminous	526.2	550.7	541.4	400.9	591.5	577.7	394.8	633.6	615.2	370.7
Sub-Bituminous	444.2	536.1	546.1	323.3	657.9	653.4	280.6	782.3	757.6	317.4
Lignite	93.6	95.8	84.2	40.3	90.6	59.5	42.3	89.0	67.4	45.8
Low Sulfur	527.0	607.9	665.8	449.1	747.1	765.3	366.0	870.9	878.7	398.7
Medium Sulfur	423.0	424.6	363.8	225.6	415.8	399.2	234.5	434.8	416.9	217.5
High Sulfur	155.4	192.5	184.5	132.1	210.2	159.1	149.1	226.5	171.7	144.4
Underground	356.9	382.4	377.0	292.7	419.6	412.9	271.9	452.1	440.5	277.6
Surface	748.5	842.6	837.1	514.1	953.4	910.7	477.6	1080.1	1026.8	483.0
U.S. Total	**1105.4**	**1225.0**	**1214.1**	**806.8**	**1373.0**	**1323.6**	**749.6**	**1532.2**	**1467.3**	**760.6**

[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, Northern Tennessee.
Southern Appalachia: Alabama, Southern 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, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

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

Capacity and Generation	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.29	78.69	78.69	78.69	78.68	78.68	78.68	78.68	78.68	78.68
Geothermal[2]	2.89	4.05	4.05	5.51	6.28	6.39	10.09	7.36	7.44	10.37
Municipal Solid Waste[3]	3.49	3.91	3.91	4.79	3.95	3.91	4.84	3.95	3.92	4.85
Wood and Other Biomass[4,5]	1.83	2.46	2.28	4.15	3.47	2.92	62.63	5.07	3.92	75.91
Solar Thermal	0.33	0.43	0.43	0.43	0.49	0.49	0.49	0.52	0.52	0.52
Solar Photovoltaic[5]	0.02	0.15	0.15	0.15	0.32	0.32	0.32	0.41	0.41	0.41
Wind	4.83	8.72	8.64	53.23	14.19	20.42	93.43	16.54	30.25	93.67
Total	**91.69**	**98.41**	**98.15**	**146.95**	**107.39**	**113.15**	**250.49**	**112.53**	**125.13**	**264.41**
Generation (billion kilowatthours)										
Conventional Hydropower	255.78	304.37	304.37	304.32	304.63	304.62	304.57	304.80	304.79	304.72
Geothermal[2]	13.36	23.54	23.55	35.04	41.95	42.92	71.31	50.84	51.53	73.50
Municipal Solid Waste[3]	20.02	28.09	28.08	34.99	28.44	28.18	35.47	28.50	28.24	35.54
Wood and Other Biomass[5]	8.67	24.21	29.58	32.60	30.79	39.39	406.38	34.56	44.16	514.70
Dedicated Plants	6.33	14.26	13.08	20.53	21.50	17.82	406.38	31.22	23.59	514.70
Cofiring	2.34	9.95	16.50	12.06	9.30	21.57	0.00	3.34	20.58	0.00
Solar Thermal	0.54	0.84	0.84	0.84	1.04	1.04	1.04	1.11	1.11	1.11
Solar Photovoltaic[6]	0.00	0.36	0.36	0.36	0.79	0.79	0.79	1.02	1.02	1.02
Wind	10.51	26.41	26.14	177.28	45.77	68.09	313.51	54.29	104.27	314.43
Total	**308.87**	**407.81**	**412.92**	**585.42**	**453.42**	**485.03**	**1133.07**	**475.11**	**535.11**	**1245.02**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[7]										
Municipal Solid Waste	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Biomass	3.91	5.36	5.35	5.14	7.27	7.26	7.19	8.04	8.03	7.97
Total	**4.16**	**5.61**	**5.61**	**5.39**	**7.52**	**7.51**	**7.45**	**8.29**	**8.28**	**8.22**
Other End-Use Generators[8]										
Conventional Hydropower[9]	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.40	0.40	0.47	0.85	0.90	2.12	1.52	1.62	3.48
Total	**1.06**	**1.42**	**1.42**	**1.49**	**1.88**	**1.92**	**3.14**	**2.54**	**2.64**	**4.50**
Generation (billion kilowatthours)										
Combined Heat and Power[7]										
Municipal Solid Waste	1.84	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Biomass	28.16	36.65	36.61	35.38	47.79	47.75	47.36	52.31	52.25	51.90
Total	**30.00**	**38.75**	**38.71**	**37.48**	**49.89**	**49.85**	**49.46**	**54.41**	**54.35**	**54.00**
Other End-Use Generators[8]										
Conventional Hydropower[9]	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.09	0.86	0.86	1.00	1.84	1.94	4.39	3.25	3.46	7.19
Total	**4.20**	**4.97**	**4.97**	**5.11**	**5.95**	**6.05**	**8.49**	**7.35**	**7.57**	**11.29**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2002 Table 10.6 for estimates of 1989-2001 PV shipments, including exports, for both grid-connected and off-grid applications.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[8]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.
[9]Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2004. 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: 2002 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2002 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

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

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Residential										
Petroleum	104.0	110.6	110.6	110.6	107.4	107.5	107.8	104.7	104.8	105.1
Natural Gas	267.2	301.0	301.0	294.5	323.7	323.4	323.4	332.8	332.6	334.5
Coal	1.1	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Electricity	816.7	897.8	887.3	628.6	1010.7	985.6	600.8	1091.2	1056.6	585.9
Total	**1189.0**	**1310.6**	**1300.1**	**1034.9**	**1443.0**	**1417.6**	**1033.2**	**1529.8**	**1495.1**	**1026.6**
Commercial										
Petroleum	52.6	66.9	67.0	67.4	70.8	70.9	71.7	72.6	72.9	73.6
Natural Gas	169.4	187.6	187.6	183.0	207.9	207.6	219.5	218.7	218.8	238.5
Coal	9.2	9.3	9.3	9.3	9.2	9.2	9.2	9.2	9.2	9.1
Electricity	778.0	930.8	921.0	663.0	1131.2	1101.8	665.3	1259.6	1217.2	664.0
Total	**1009.1**	**1194.5**	**1184.8**	**922.7**	**1419.1**	**1389.6**	**965.6**	**1560.2**	**1518.0**	**985.3**
Industrial[1]										
Petroleum	412.8	366.4	366.0	361.4	409.8	409.9	398.6	428.7	428.7	413.8
Natural Gas[2]	432.7	519.2	519.7	511.6	591.7	595.5	626.8	629.8	636.1	683.0
Coal	185.1	194.6	194.2	190.6	185.8	185.0	178.7	183.4	182.5	175.1
Electricity	640.0	709.4	703.1	504.2	814.7	794.4	477.7	898.9	868.4	469.8
Total	**1670.6**	**1789.6**	**1782.9**	**1567.7**	**2002.0**	**1984.7**	**1681.8**	**2140.7**	**2115.7**	**1741.6**
Transportation										
Petroleum[3]	1811.2	2198.2	2199.0	2174.1	2611.3	2612.0	2599.7	2829.1	2829.5	2818.0
Natural Gas[4]	35.2	41.0	41.1	40.8	49.9	50.6	51.6	51.4	52.1	53.9
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	14.2	16.6	16.5	12.7	19.8	19.5	12.7	22.3	21.7	12.8
Total	**1860.6**	**2255.7**	**2256.5**	**2227.6**	**2681.0**	**2682.1**	**2664.0**	**2902.7**	**2903.4**	**2884.7**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	2380.5	2742.1	2742.5	2713.5	3199.3	3200.3	3177.9	3435.0	3435.9	3410.5
Natural Gas	904.4	1048.8	1049.4	1030.0	1173.2	1177.0	1221.3	1232.7	1239.7	1309.9
Coal	195.4	205.0	204.6	201.0	196.1	195.3	189.0	193.7	192.8	185.3
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	2249.0	2554.6	2527.9	1808.4	2976.5	2901.3	1756.4	3271.9	3163.9	1732.5
Total	**5729.3**	**6550.5**	**6524.3**	**5752.9**	**7545.1**	**7473.9**	**6344.5**	**8133.4**	**8032.2**	**6638.2**
Electric Power[6]										
Petroleum	72.2	50.6	42.1	27.8	61.2	50.0	22.9	60.8	45.8	20.8
Natural Gas	299.1	358.5	359.1	437.8	460.5	473.8	463.3	450.0	463.1	431.2
Coal	1877.8	2145.4	2126.7	1342.7	2454.7	2377.5	1270.2	2761.1	2655.1	1280.4
Total	**2249.0**	**2554.6**	**2527.9**	**1808.4**	**2976.5**	**2901.3**	**1756.4**	**3271.9**	**3163.9**	**1732.5**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	2452.7	2792.7	2784.6	2741.4	3260.5	3250.3	3200.7	3495.9	3481.6	3431.4
Natural Gas	1203.4	1407.4	1408.4	1467.8	1633.8	1650.8	1684.5	1682.7	1702.7	1741.1
Coal	2073.2	2350.4	2331.3	1543.8	2650.8	2572.8	1459.3	2954.8	2847.8	1465.7
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**5729.4**	**6550.5**	**6524.3**	**5752.9**	**7545.1**	**7473.9**	**6344.5**	**8133.4**	**8032.2**	**6638.2**
Carbon Dioxide Emissions (tons per person)	**19.8**	**21.2**	**21.1**	**18.6**	**22.5**	**22.3**	**19.0**	**23.4**	**23.1**	**19.1**

[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 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 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

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

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords	Reference	Inhofe	Jeffords
Emissions										
Nitrogen Oxides (million tons)	4.39	3.48	2.19	1.50	3.66	1.79	0.61	3.72	1.79	0.61
Sulfur Dioxide (million tons)	10.19	9.62	6.18	3.63	8.95	4.18	1.25	8.95	3.62	1.18
From Coal	9.95	9.41	6.03	3.60	8.72	4.05	1.20	8.73	3.52	1.14
From Oil/Other	0.24	0.21	0.16	0.03	0.23	0.13	0.06	0.21	0.11	0.04
Mercury (tons)	50.81	52.60	39.55	3.97	53.50	28.87	3.70	54.60	29.01	3.73
Carbon Dioxide (million metric tons)	2248.9	2554.56	2527.85	1808.41	2976.48	2901.26	1756.39	3271.93	3163.87	1732.50
Allowance Prices										
Nitrogen Oxides (2002 dollars per ton)										
Regional/Seasonal	0.00	4347.54	0.00	0.00	4929.66	0.00	0.00	5114.85	0.00	0.00
East/Annual	0.00	0.00	2039.54	1388.28	0.00	2492.62	0.00	0.00	2775.56	0.00
West/Annual	0.00	0.00	1123.82	1388.31	0.00	1572.96	0.00	0.00	1715.38	0.00
Sulfur Dioxide (2002 dollars per ton)	108.61	150.41	604.84	372.57	258.59	1392.61	0.00	173.48	1414.07	0.00
Mercury (thousand 2002 dollars per pound)	0.00	0.00	15.11	0.00	0.00	35.00	0.00	0.00	35.00	0.00
Carbon Dioxide (2002 dollars per million metric ton)	0.00	0.00	0.00	35.21	0.00	0.00	30.86	0.00	0.00	29.41
Retrofits (gigawatts)										
Scrubber[6]										
Planned	2.26	20.20	20.20	20.20	23.05	23.05	23.05	23.05	23.05	23.05
Unplanned	0.00	1.60	37.10	50.48	1.60	82.46	106.80	1.60	100.33	106.80
Total	2.26	21.80	57.29	70.68	24.65	105.50	129.85	24.65	123.38	129.85
Nitrogen Oxides Controls										
Combustion	0.00	14.85	29.13	19.44	15.41	32.41	20.01	15.76	32.76	20.56
SCR Post-combustion	6.32	82.04	116.70	143.51	90.14	154.52	206.22	92.89	160.09	206.22
SNCR Post-combustion	0.00	11.43	10.24	4.53	16.75	24.41	4.53	22.81	37.88	4.53
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs per million Btu)	527.04	607.94	665.78	449.08	747.05	765.31	366.00	870.88	878.70	398.69
Medium Sulfur	422.96	424.57	363.81	225.64	415.78	399.17	234.50	434.80	416.93	217.53
High Sulfur (> 1.67 lbs per million Btu)	155.38	192.53	184.50	132.06	210.16	159.08	149.06	226.54	171.70	144.37
Interregional Sulfur Dioxide Allowances										
Target (million tons)	9.48	8.95	4.50	2.25	8.95	3.00	2.25	8.95	3.00	2.25
Cumulative Banked Allowances	9.23	2.38	18.81	4.96	0.00	9.62	0.00	0.00	5.11	0.00
Coal Characteristics										
SO_2 Content (lbs per million Btu)	1.86	1.89	1.82	1.93	1.82	1.68	2.20	1.78	1.64	2.11
Mercury Content (lbs per trillion Btu)	7.55	7.23	7.01	6.57	7.00	6.72	6.98	6.91	6.68	6.95
ACI Controls (gigawatts)										
Spray Cooling	0.00	0.00	0.00	134.35	0.00	0.00	145.87	0.00	0.00	146.88
Supplemental Fabric Filter	0.00	0.00	0.00	46.58	0.00	0.00	58.14	0.00	0.00	59.73
ACI Mercury Removal (tons)	**0.00**	**0.00**	**2.49**	**9.73**	**0.00**	**9.35**	**6.04**	**0.00**	**9.57**	**6.57**
Allowance Revenues (billion 2002 dollars)										
Nitrogen Oxides	0.00	2.06	3.88	2.10	2.33	3.88	0.00	2.42	4.29	0.00
Sulfur Dioxide	1.42	1.61	3.65	2.08	2.67	6.47	0.00	1.90	5.94	0.00
Mercury	0.00	0.00	1.63	0.00	0.00	2.02	0.00	0.00	2.03	0.00
Carbon Dioxide	0.00	0.00	0.00	63.67	0.00	0.00	54.20	0.00	0.00	50.96
Total	**1.42**	**3.67**	**9.16**	**67.84**	**5.00**	**12.37**	**54.20**	**4.32**	**12.26**	**50.96**

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 2002 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCS3PWS.D040904A, and INJF4P.D041604A.

Appendix C

Comparison Tables for Reference, Carper International, and Carper Domestic Cases

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

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Production										
Crude Oil and Lease Condensate	11.91	12.61	12.60	12.60	10.52	10.53	10.54	9.81	9.86	9.85
Natural Gas Plant Liquids	2.56	3.19	3.19	3.20	3.44	3.48	3.49	3.44	3.53	3.54
Dry Natural Gas	19.56	21.76	21.78	21.87	24.20	24.52	24.60	24.38	25.17	25.29
Coal	22.70	25.11	24.74	24.60	27.88	25.39	24.54	30.88	26.36	25.24
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	8.61	8.61	8.61	8.61
Renewable Energy[1]	5.84	7.22	7.39	7.62	8.56	10.13	11.36	9.20	11.57	13.30
Other[2]	1.13	0.89	0.88	0.89	0.81	0.81	0.81	0.84	0.84	0.84
Total	**71.85**	**79.19**	**79.01**	**79.20**	**84.03**	**83.47**	**83.94**	**87.16**	**85.94**	**86.67**
Imports										
Crude Oil[3]	19.84	24.53	24.44	24.41	31.43	31.46	31.38	34.07	34.05	33.93
Petroleum Products[4]	4.76	5.69	5.53	5.51	8.25	7.93	7.87	10.10	9.77	9.72
Natural Gas	4.10	5.67	5.71	5.72	7.50	7.76	7.79	8.17	8.89	8.77
Other Imports[5]	0.52	0.95	0.97	0.62	1.12	1.13	0.57	1.18	1.18	0.51
Total	**29.22**	**36.84**	**36.65**	**36.26**	**48.30**	**48.28**	**47.61**	**53.52**	**53.89**	**52.94**
Exports										
Petroleum[6]	2.03	2.14	2.14	2.14	2.13	2.14	2.13	2.14	2.15	2.14
Natural Gas	0.52	0.81	0.81	0.81	0.80	0.77	0.77	0.72	0.66	0.67
Coal	1.03	0.89	0.89	0.89	0.69	0.69	0.63	0.58	0.58	0.58
Total	**3.58**	**3.85**	**3.84**	**3.84**	**3.61**	**3.60**	**3.54**	**3.44**	**3.39**	**3.39**
Discrepancy[7]	**-0.23**	**0.32**	**0.31**	**0.33**	**0.47**	**0.46**	**0.46**	**0.56**	**0.57**	**0.54**
Consumption										
Petroleum Products[8]	38.11	44.25	44.00	43.96	51.64	51.39	51.27	55.34	55.10	54.96
Natural Gas	23.37	26.78	26.84	26.95	31.09	31.68	31.80	32.02	33.59	33.58
Coal	22.18	25.08	24.73	24.20	28.27	25.79	24.42	31.49	26.98	25.19
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	8.61	8.61	8.61	8.61
Renewable Energy[1]	5.84	7.22	7.39	7.62	8.56	10.13	11.36	9.20	11.57	13.30
Other[9]	0.07	0.11	0.13	0.14	0.07	0.08	0.09	0.03	0.03	0.03
Total	**97.72**	**111.86**	**111.50**	**111.29**	**128.24**	**127.69**	**127.55**	**136.68**	**135.88**	**135.68**
Net Imports - Petroleum	**22.57**	**28.07**	**27.83**	**27.78**	**37.55**	**37.25**	**37.12**	**42.04**	**41.67**	**41.51**
Prices (2002 dollars per unit)										
World Oil Price (dollars per barrel)[10]	23.68	24.17	24.17	24.17	26.02	26.02	26.02	27.00	27.00	27.00
Natural Gas Wellhead Price (dollars per thousand cubic feet)[11]	2.95	3.40	3.43	3.44	4.15	4.27	4.31	4.43	4.48	4.49
Coal Minemouth Price (dollars per ton)	17.90	16.71	16.79	17.02	16.51	15.83	16.00	16.58	15.58	15.87
Average Electricity Price (cents per kilowatthour)	7.2	6.7	6.8	6.9	6.8	7.1	7.2	6.9	7.2	7.4

[1]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal solid waste; other biomass; wind; photovoltaic and solar thermal sources; non-electric energy from renewable sources, such as active and passive solar systems, and wood; and both the ethanol and gasoline components of E85, but not the ethanol components of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[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 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 petroleum supply values: EIA, *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). Other 2002 values: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002) and EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

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

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Energy Consumption										
Residential										
Distillate Fuel	0.89	0.93	0.93	0.93	0.85	0.85	0.85	0.80	0.81	0.81
Kerosene	0.07	0.11	0.11	0.11	0.10	0.10	0.10	0.09	0.09	0.09
Liquefied Petroleum Gas	0.53	0.56	0.56	0.56	0.62	0.62	0.62	0.64	0.64	0.64
Petroleum Subtotal	1.48	1.60	1.60	1.60	1.57	1.57	1.57	1.53	1.53	1.54
Natural Gas	5.06	5.70	5.70	5.70	6.13	6.11	6.11	6.30	6.28	6.29
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	0.40	0.40	0.40	0.41	0.41	0.41	0.40	0.40	0.40
Electricity	4.33	4.86	4.83	4.82	5.57	5.51	5.50	5.91	5.86	5.81
Delivered Energy	**11.28**	**12.58**	**12.55**	**12.54**	**13.68**	**13.61**	**13.60**	**14.16**	**14.09**	**14.05**
Electricity Related Losses	9.60	10.46	10.34	10.27	11.39	11.26	11.21	11.88	11.66	11.58
Total	**20.88**	**23.04**	**22.89**	**22.81**	**25.07**	**24.87**	**24.81**	**26.04**	**25.75**	**25.63**
Commercial										
Distillate Fuel	0.49	0.63	0.63	0.63	0.68	0.69	0.69	0.70	0.71	0.71
Residual Fuel	0.08	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Liquefied Petroleum Gas	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Petroleum Subtotal	0.72	0.93	0.93	0.93	0.98	0.99	0.99	1.01	1.01	1.02
Natural Gas	3.21	3.55	3.55	3.55	3.94	3.92	3.91	4.14	4.13	4.13
Coal	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Renewable Energy[3]	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Electricity	4.12	5.04	5.01	5.01	6.23	6.16	6.15	6.83	6.74	6.71
Delivered Energy	**8.25**	**9.72**	**9.69**	**9.69**	**11.34**	**11.26**	**11.25**	**12.17**	**12.08**	**12.05**
Electricity Related Losses	9.15	10.84	10.73	10.66	12.75	12.58	12.55	13.71	13.42	13.37
Total	**17.40**	**20.56**	**20.43**	**20.34**	**24.09**	**23.84**	**23.80**	**25.89**	**25.50**	**25.42**
Industrial[4]										
Distillate Fuel	1.16	1.18	1.18	1.18	1.34	1.34	1.33	1.43	1.43	1.42
Liquefied Petroleum Gas	2.22	2.36	2.36	2.36	2.74	2.74	2.74	2.95	2.95	2.95
Petrochemical Feedstock	1.22	1.35	1.35	1.35	1.54	1.54	1.54	1.63	1.62	1.62
Residual Fuel	0.20	0.21	0.21	0.21	0.22	0.22	0.22	0.23	0.23	0.23
Motor Gasoline[2]	0.16	0.16	0.16	0.16	0.18	0.18	0.18	0.19	0.19	0.19
Other Petroleum[5]	4.03	4.40	4.39	4.39	4.97	4.98	4.97	5.17	5.19	5.19
Petroleum Subtotal	9.00	9.65	9.64	9.64	10.99	11.00	10.99	11.60	11.61	11.60
Natural Gas	7.43	8.62	8.62	8.62	9.83	9.87	9.90	10.54	10.61	10.69
Lease and Plant Fuel[6]	1.35	1.34	1.34	1.34	1.52	1.53	1.54	1.54	1.58	1.59
Natural Gas Subtotal	8.78	9.96	9.96	9.97	11.35	11.41	11.44	12.08	12.19	12.28
Metallurgical Coal	0.62	0.65	0.65	0.65	0.53	0.52	0.52	0.47	0.47	0.47
Steam Coal	1.47	1.43	1.43	1.43	1.47	1.46	1.46	1.49	1.48	1.48
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.00
Coal Subtotal	2.12	2.09	2.09	2.09	2.00	1.99	1.99	1.97	1.96	1.95
Renewable Energy[7]	1.66	2.00	2.00	2.00	2.48	2.48	2.48	2.70	2.70	2.70
Electricity	3.39	3.84	3.83	3.83	4.49	4.44	4.43	4.87	4.82	4.79
Delivered Energy	**24.94**	**27.54**	**27.51**	**27.52**	**31.31**	**31.32**	**31.32**	**33.22**	**33.28**	**33.32**
Electricity Related Losses	7.53	8.26	8.19	8.14	9.18	9.07	9.04	9.79	9.60	9.54
Total	**32.47**	**35.80**	**35.71**	**35.66**	**40.49**	**40.39**	**40.36**	**43.01**	**42.87**	**42.87**

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

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Transportation										
Distillate Fuel[8]	5.12	6.43	6.43	6.42	8.03	8.01	8.00	8.94	8.90	8.88
Jet Fuel[9]	3.34	3.93	3.93	3.92	4.69	4.69	4.69	4.91	4.91	4.92
Motor Gasoline[2]	16.62	19.94	19.96	19.96	23.38	23.40	23.41	25.32	25.34	25.34
Residual Fuel	0.71	0.79	0.79	0.79	0.82	0.81	0.81	0.83	0.82	0.82
Liquefied Petroleum Gas	0.02	0.06	0.06	0.06	0.08	0.08	0.08	0.09	0.09	0.09
Other Petroleum[10]	0.24	0.26	0.25	0.25	0.30	0.30	0.30	0.32	0.32	0.32
Petroleum Subtotal	26.06	31.41	31.42	31.41	37.30	37.29	37.28	40.40	40.38	40.37
Pipeline Fuel Natural Gas	0.65	0.72	0.72	0.72	0.85	0.86	0.87	0.86	0.90	0.91
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	0.00	0.00	0.00
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.08	0.09	0.09	0.09	0.11	0.11	0.11	0.12	0.12	0.12
Delivered Energy	**26.79**	**32.27**	**32.28**	**32.28**	**38.36**	**38.36**	**38.36**	**41.50**	**41.51**	**41.52**
Electricity Related Losses	0.17	0.19	0.19	0.19	0.22	0.22	0.22	0.24	0.24	0.24
Total	**26.96**	**32.47**	**32.48**	**32.48**	**38.58**	**38.58**	**38.58**	**41.74**	**41.75**	**41.76**
Delivered Energy Consumption for All Sectors										
Distillate Fuel	7.66	9.17	9.17	9.16	10.90	10.88	10.87	11.88	11.84	11.82
Kerosene	0.09	0.16	0.16	0.16	0.14	0.14	0.15	0.13	0.13	0.13
Jet Fuel[9]	3.34	3.93	3.93	3.92	4.69	4.69	4.69	4.91	4.91	4.92
Liquefied Petroleum Gas	2.86	3.07	3.07	3.07	3.54	3.54	3.54	3.77	3.77	3.77
Motor Gasoline[2]	16.83	20.15	20.17	20.17	23.61	23.63	23.63	25.56	25.58	25.58
Petrochemical Feedstock	1.22	1.35	1.35	1.35	1.54	1.54	1.54	1.63	1.62	1.62
Residual Fuel	1.00	1.13	1.13	1.14	1.17	1.17	1.17	1.19	1.19	1.18
Other Petroleum[12]	4.26	4.63	4.62	4.62	5.24	5.25	5.24	5.47	5.49	5.49
Petroleum Subtotal	37.26	43.59	43.59	43.59	50.84	50.85	50.83	54.54	54.54	54.53
Natural Gas	15.71	17.94	17.93	17.93	20.00	20.00	20.02	21.10	21.12	21.21
Lease and Plant Fuel Plant[6]	1.35	1.34	1.34	1.34	1.52	1.53	1.54	1.54	1.58	1.59
Pipeline Natural Gas	0.65	0.72	0.72	0.72	0.85	0.86	0.87	0.86	0.90	0.91
Natural Gas Subtotal	17.72	19.99	19.99	20.00	22.36	22.39	22.42	23.49	23.60	23.71
Metallurgical Coal	0.62	0.65	0.65	0.65	0.53	0.52	0.52	0.47	0.47	0.47
Steam Coal	1.58	1.54	1.54	1.54	1.58	1.57	1.57	1.60	1.59	1.59
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.00
Coal Subtotal	2.23	2.20	2.20	2.20	2.11	2.10	2.09	2.08	2.07	2.06
Renewable Energy[13]	2.15	2.50	2.50	2.50	2.99	2.99	2.99	3.21	3.21	3.21
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	11.92	13.82	13.76	13.75	16.39	16.22	16.20	17.73	17.54	17.43
Delivered Energy	**71.27**	**82.11**	**82.04**	**82.03**	**94.69**	**94.55**	**94.53**	**101.06**	**100.96**	**100.93**
Electricity Related Losses	26.45	29.75	29.46	29.26	33.55	33.13	33.02	35.62	34.92	34.74
Total	**97.72**	**111.86**	**111.50**	**111.29**	**128.24**	**127.68**	**127.55**	**136.68**	**135.88**	**135.68**
Electric Power[14]										
Distillate Fuel	0.16	0.16	0.10	0.09	0.24	0.30	0.22	0.25	0.32	0.20
Residual Fuel	0.69	0.50	0.31	0.28	0.56	0.25	0.23	0.55	0.24	0.24
Petroleum Subtotal	0.85	0.66	0.41	0.38	0.80	0.54	0.45	0.80	0.56	0.44
Natural Gas	5.65	6.79	6.85	6.95	8.72	9.29	9.37	8.52	9.98	9.87
Steam Coal	19.96	22.88	22.53	22.00	26.16	23.69	22.32	29.41	24.91	23.13
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	8.61	8.61	8.61	8.61
Renewable Energy[15]	3.69	4.72	4.89	5.12	5.57	7.15	8.37	5.99	8.37	10.09
Electricity Imports	0.07	0.11	0.13	0.14	0.07	0.08	0.09	0.03	0.03	0.03
Total	**38.36**	**43.57**	**43.23**	**43.00**	**49.94**	**49.36**	**49.22**	**53.35**	**52.46**	**52.17**

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

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Total Energy Consumption										
Distillate Fuel	7.82	9.33	9.27	9.26	11.14	11.18	11.09	12.13	12.16	12.02
Kerosene	0.09	0.16	0.16	0.16	0.14	0.14	0.15	0.13	0.13	0.13
Jet Fuel[9]	3.34	3.93	3.93	3.92	4.69	4.69	4.69	4.91	4.91	4.92
Liquefied Petroleum Gas	2.86	3.07	3.07	3.07	3.54	3.54	3.54	3.77	3.77	3.77
Motor Gasoline[2]	16.83	20.15	20.17	20.17	23.61	23.63	23.63	25.56	25.58	25.58
Petrochemical Feedstock	1.22	1.35	1.35	1.35	1.54	1.54	1.54	1.63	1.62	1.62
Residual Fuel	1.69	1.64	1.45	1.42	1.73	1.42	1.40	1.73	1.42	1.42
Other Petroleum[12]	4.26	4.63	4.62	4.62	5.24	5.25	5.24	5.47	5.49	5.49
Petroleum Subtotal	38.11	44.25	44.00	43.96	51.64	51.39	51.27	55.34	55.10	54.96
Natural Gas	21.36	24.73	24.78	24.88	28.72	29.29	29.40	29.63	31.11	31.09
Lease and Plant Fuel[6]	1.35	1.34	1.34	1.34	1.52	1.53	1.54	1.54	1.58	1.59
Pipeline Natural Gas	0.65	0.72	0.72	0.72	0.85	0.86	0.87	0.86	0.90	0.91
Natural Gas Subtotal	23.37	26.78	26.84	26.95	31.09	31.68	31.80	32.02	33.59	33.58
Metallurgical Coal	0.62	0.65	0.65	0.65	0.53	0.52	0.52	0.47	0.47	0.47
Steam Coal	21.54	24.42	24.07	23.54	27.74	25.26	23.90	31.01	26.50	24.72
Net Coal Coke Imports	0.03	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.00
Coal Subtotal	22.18	25.08	24.73	24.20	28.27	25.79	24.42	31.49	26.98	25.19
Nuclear Power	8.15	8.42	8.42	8.42	8.61	8.61	8.61	8.61	8.61	8.61
Renewable Energy[16]	5.84	7.22	7.39	7.62	8.56	10.13	11.36	9.20	11.57	13.30
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.07	0.11	0.13	0.14	0.07	0.08	0.09	0.03	0.03	0.03
Total	**97.72**	**111.86**	**111.50**	**111.29**	**128.24**	**127.69**	**127.55**	**136.68**	**135.88**	**135.68**
Energy Use and Related Statistics										
Delivered Energy Use	71.27	82.11	82.04	82.03	94.69	94.55	94.53	101.06	100.96	100.93
Total Energy Use	97.72	111.86	111.50	111.29	128.24	127.68	127.55	136.68	135.88	135.68
Population (millions)	288.93	309.28	309.28	309.28	334.61	334.61	334.61	347.53	347.53	347.53
Gross Domestic Product (billion 1996 dollars)	9440	12198	12190	12190	16194	16189	16189	18523	18518	18516
Carbon Dioxide Emissions (million metric tons)	5729.4	6550.5	6499.4	6452.4	7545.1	7321.5	7189.5	8133.4	7770.6	7590.3

[1]Includes wood used for residential heating.
[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.
[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 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, aviation gasoline, lubricants, still gas, asphalt, road oil, petroleum coke, and miscellaneous petroleum products.
[13]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, photovoltaic and solar thermal sources. Includes ethanol components of E85; excludes ethanol blends (10 percent or less) in motor gasoline. Excludes net electricity imports and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 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: 2002 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 population and gross domestic product: Global Insight macroeconomic model T250803. 2002 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

Table C3. Energy Prices by Sector and Source
(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Residential	**14.73**	**14.18**	**14.42**	**14.47**	**14.94**	**15.33**	**15.44**	**15.27**	**15.66**	**16.01**
Primary Energy[1]	8.14	8.14	8.15	8.16	8.64	8.73	8.76	8.90	8.95	8.97
Petroleum Products[2]	9.87	9.89	9.89	9.89	10.86	10.85	10.85	11.27	11.27	11.27
Distillate Fuel	8.23	7.82	7.81	7.81	8.37	8.36	8.37	8.54	8.54	8.53
Liquefied Petroleum Gas	12.92	13.86	13.84	13.84	14.82	14.81	14.81	15.20	15.18	15.19
Natural Gas	7.64	7.66	7.68	7.68	8.09	8.19	8.24	8.33	8.39	8.42
Electricity	24.73	23.28	23.92	24.04	23.66	24.55	24.78	23.72	24.63	25.49
Commercial	**14.70**	**13.79**	**14.10**	**14.15**	**14.87**	**15.35**	**15.45**	**15.21**	**15.69**	**16.07**
Primary Energy[1]	6.38	6.46	6.47	6.48	6.99	7.07	7.10	7.23	7.28	7.29
Petroleum Products[2]	6.88	6.33	6.32	6.32	6.81	6.80	6.80	6.98	6.96	6.96
Distillate Fuel	6.07	5.45	5.45	5.45	5.99	5.99	5.99	6.15	6.15	6.15
Residual Fuel	4.21	4.13	4.09	4.08	4.41	4.35	4.35	4.55	4.49	4.49
Natural Gas	6.40	6.63	6.65	6.66	7.17	7.27	7.31	7.42	7.49	7.51
Electricity	22.83	20.46	21.06	21.17	21.22	22.08	22.24	21.35	22.24	22.92
Industrial[3]	**6.31**	**6.45**	**6.53**	**6.55**	**7.18**	**7.32**	**7.36**	**7.42**	**7.55**	**7.62**
Primary Energy	4.77	5.13	5.14	5.15	5.83	5.88	5.89	6.08	6.10	6.10
Petroleum Products[2]	6.35	6.83	6.82	6.82	7.56	7.55	7.55	7.79	7.78	7.78
Distillate Fuel	6.21	5.68	5.67	5.67	6.24	6.23	6.23	6.40	6.40	6.39
Liquefied Petroleum Gas	8.28	9.68	9.66	9.66	10.67	10.66	10.66	11.10	11.03	11.03
Residual Fuel	3.89	3.74	3.73	3.72	4.03	4.00	3.99	4.17	4.14	4.14
Natural Gas[4]	3.75	4.06	4.09	4.11	4.76	4.88	4.92	5.03	5.11	5.11
Metallurgical Coal	1.87	1.96	1.97	1.97	1.84	1.85	1.85	1.77	1.77	1.77
Steam Coal	1.48	1.57	1.57	1.58	1.54	1.49	1.49	1.52	1.45	1.45
Electricity	14.74	13.42	13.91	14.03	14.01	14.74	14.91	14.04	14.83	15.34
Transportation	**9.91**	**10.52**	**10.51**	**10.51**	**10.58**	**10.59**	**10.59**	**10.74**	**10.75**	**10.75**
Primary Energy	9.88	10.49	10.48	10.48	10.55	10.56	10.55	10.72	10.72	10.71
Petroleum Products[2]	9.88	10.49	10.48	10.48	10.56	10.56	10.56	10.72	10.72	10.72
Distillate Fuel[5]	9.41	10.16	10.13	10.13	10.09	10.11	10.11	10.12	10.14	10.14
Jet Fuel[6]	5.97	5.76	5.76	5.76	6.09	6.08	6.08	6.31	6.31	6.31
Motor Gasoline[7]	11.15	11.88	11.87	11.87	11.90	11.90	11.90	12.06	12.06	12.05
Residual Fuel	3.77	3.60	3.58	3.58	3.87	3.86	3.86	4.02	4.00	4.00
Liquefied Petroleum Gas[8]	15.00	14.94	14.93	14.92	15.55	15.54	15.53	15.84	15.82	15.83
Natural Gas[9]	7.38	8.24	8.26	8.27	8.91	9.03	9.07	9.11	9.18	9.20
Ethanol (E85)[10]	15.19	17.21	17.24	17.31	18.24	18.33	18.42	18.66	18.75	18.83
Electricity	20.89	19.62	20.17	20.26	20.05	20.80	20.97	19.88	20.74	21.26
Average End-Use Energy	**10.10**	**10.23**	**10.32**	**10.35**	**10.73**	**10.88**	**10.92**	**10.95**	**11.10**	**11.22**
Primary Energy	7.70	8.22	8.22	8.22	8.63	8.66	8.67	8.86	8.87	8.87
Electricity	21.21	19.49	20.07	20.18	20.07	20.90	21.09	20.12	20.99	21.68
Electric Power[11]										
Fossil Fuel Average	1.89	1.92	2.06	2.48	2.15	2.78	3.56	2.13	2.99	3.79
Petroleum Products	4.33	4.21	4.34	4.73	4.66	5.50	6.15	4.85	5.85	6.47
Distillate Fuel	5.58	4.91	5.03	5.36	5.46	5.90	6.55	5.63	6.20	6.92
Residual Fuel	4.04	3.99	4.11	4.52	4.32	5.02	5.76	4.50	5.38	6.10
Natural Gas	3.77	4.08	4.21	4.47	4.75	5.28	5.79	4.99	5.62	6.13
Steam Coal	1.25	1.22	1.37	1.82	1.21	1.74	2.57	1.22	1.88	2.74

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

(2002 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Average Price to All Users[12]										
Petroleum Products[2]	8.94	9.58	9.60	9.60	9.84	9.88	9.89	10.04	10.07	10.09
Distillate Fuel	8.52	8.95	8.96	8.96	9.15	9.15	9.18	9.26	9.25	9.30
Jet Fuel	5.97	5.76	5.76	5.76	6.09	6.08	6.08	6.31	6.31	6.31
Liquefied Petroleum Gas	9.27	10.61	10.59	10.59	11.56	11.56	11.56	11.96	11.91	11.91
Motor Gasoline[7]	11.15	11.88	11.87	11.87	11.90	11.90	11.90	12.06	12.06	12.05
Residual Fuel	3.92	3.78	3.76	3.84	4.08	4.13	4.23	4.23	4.30	4.43
Natural Gas	5.08	5.27	5.32	5.40	5.81	6.03	6.22	6.07	6.27	6.44
Coal	1.27	1.24	1.38	1.80	1.23	1.73	2.50	1.24	1.85	2.66
Ethanol (E85)[10]	15.19	17.21	17.24	17.31	18.24	18.33	18.42	18.66	18.75	18.83
Electricity	21.21	19.49	20.07	20.18	20.07	20.90	21.09	20.12	20.99	21.68
Non-Renewable Energy Expenditures by Sector (billion 2002 dollars)										
Residential	160.36	172.65	175.22	175.64	198.31	202.47	203.70	210.08	214.30	218.37
Commercial	119.80	132.62	135.24	135.69	167.25	171.33	172.32	183.65	188.03	191.98
Industrial	120.90	133.42	135.15	135.72	168.58	172.25	173.22	185.98	189.71	192.05
Transportation	259.09	331.86	331.67	331.66	396.83	396.91	396.79	436.57	436.46	436.30
Total Non-Renewable Expenditures	660.15	770.54	777.27	778.71	930.96	942.97	946.04	1016.28	1028.49	1038.70
Transportation Renewable Expenditures	0.01	0.03	0.03	0.03	0.06	0.06	0.06	0.07	0.07	0.07
Total Expenditures	**660.16**	**770.58**	**777.31**	**778.75**	**931.02**	**943.02**	**946.09**	**1016.35**	**1028.56**	**1038.78**

[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 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol actually varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[12]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
Note: Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 prices for motor gasoline, distillate, and jet fuel are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2002*, http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/petroleum_marketing_annual/current/pdf/pmaall.pdf (August 2003). 2002 residential, commercial, and transportation natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 electric power sector natural gas prices: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2002 industrial natural gas delivered prices based on: EIA, *Manufacturing Energy Consumption Survey 1998.* 2002 coal prices based on EIA, *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003) and EIA, AEO2004 National Energy Modeling System run INBASE.D040904A. 2002 electricity prices: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). 2002 ethanol prices derived from weekly spot prices in the Oxy Fuel News. **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

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

Supply, Disposition, and Prices	2002	Projections 2010 Reference	2010 Carper Intl	2010 Carper Domestic	2020 Reference	2020 Carper Intl	2020 Carper Domestic	2025 Reference	2025 Carper Intl	2025 Carper Domestic
Generation by Fuel Type										
Electric Power Sector[1]										
Power Only[2]										
Coal	1875	2181	2127	2086	2556	2242	2114	2954	2410	2225
Petroleum	77	62	39	36	76	58	46	76	60	44
Natural Gas[3]	450	643	670	686	957	1087	1114	966	1227	1225
Nuclear Power	780	806	806	806	824	824	824	824	824	824
Pumped Storage/Other	-9	-9	-9	-9	-9	-9	-9	-9	-9	-9
Renewable Sources[4]	304	404	417	439	449	588	694	471	691	864
Distributed Generation (Natural Gas)	0	0	0	0	4	4	4	6	7	6
Non-Utility Generation for Own Use	-34	-37	-42	-42	-37	-41	-42	-37	-42	-42
Total	**3443**	**4050**	**4008**	**4003**	**4820**	**4751**	**4745**	**5250**	**5169**	**5137**
Combined Heat and Power[5]										
Coal	32	34	36	35	34	36	35	33	36	34
Petroleum	6	1	1	1	2	2	2	2	2	2
Natural Gas	148	176	188	189	163	168	163	148	155	150
Renewable Sources	5	4	4	4	4	4	4	4	4	4
Non-Utility Generation for Own Use	-11	-24	-24	-24	-24	-24	-24	-24	-24	-24
Total	**183**	**190**	**205**	**205**	**179**	**186**	**180**	**164**	**173**	**165**
Net Available to the Grid	**3626**	**4240**	**4213**	**4208**	**4999**	**4937**	**4924**	**5414**	**5342**	**5302**
End-Use Sector Generation										
Combined Heat and Power[6]										
Coal	21	21	21	21	21	21	21	21	21	21
Petroleum	5	12	12	12	18	19	19	19	19	19
Natural Gas	84	105	106	107	146	160	163	174	194	204
Other Gaseous Fuels[7]	5	9	9	9	12	12	13	13	13	14
Renewable Sources[4]	30	39	39	39	50	50	50	54	54	54
Other[8]	11	11	11	11	11	11	11	11	11	11
Total	**157**	**197**	**199**	**199**	**259**	**273**	**277**	**292**	**313**	**324**
Other End-Use Generators[9]	4	5	5	5	6	6	6	7	8	8
Generation for Own Use	-134	-156	-157	-157	-187	-194	-196	-207	-218	-224
Total Sales to the Grid	**27**	**46**	**47**	**47**	**77**	**85**	**86**	**91**	**102**	**108**
Total Electricity Generation	**3831**	**4504**	**4483**	**4478**	**5325**	**5282**	**5273**	**5774**	**5729**	**5700**
Net Imports	**22**	**32**	**38**	**40**	**21**	**25**	**27**	**7**	**9**	**10**
Electricity Sales by Sector										
Residential	1268	1424	1416	1414	1631	1616	1612	1733	1716	1703
Commercial	1208	1476	1469	1468	1825	1805	1804	2000	1976	1966
Industrial	994	1125	1122	1121	1315	1302	1299	1428	1412	1403
Transportation	22	26	26	26	32	32	32	35	35	35
Total	**3492**	**4051**	**4033**	**4030**	**4803**	**4755**	**4747**	**5196**	**5140**	**5107**
End-Use Prices[10] (2002 cents per kilowatthour)										
Residential	8.4	7.9	8.2	8.2	8.1	8.4	8.5	8.1	8.4	8.7
Commercial	7.8	7.0	7.2	7.2	7.2	7.5	7.6	7.3	7.6	7.8
Industrial	5.0	4.6	4.7	4.8	4.8	5.0	5.1	4.8	5.1	5.2
Transportation	7.1	6.7	6.9	6.9	6.8	7.1	7.2	6.8	7.1	7.3
All Sectors Average	**7.2**	**6.7**	**6.8**	**6.9**	**6.8**	**7.1**	**7.2**	**6.9**	**7.2**	**7.4**
Prices by Service Category[10] (2002 cents per kilowatthour)										
Generation	4.6	4.1	4.3	4.4	4.5	4.7	4.8	4.5	4.8	5.0
Transmission	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
Distribution	2.0	1.9	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.7

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

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Electric Power Sector Emissions[1]										
Sulfur Dioxide (million tons)	10.19	9.62	5.33	5.32	8.95	3.31	3.28	8.95	2.84	2.86
Nitrogen Oxide (million tons)	4.39	3.48	1.81	1.80	3.66	1.70	1.70	3.72	1.70	1.70
Mercury (tons)	50.81	52.60	24.00	24.00	53.50	10.00	10.00	54.60	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 2002 are model results and may differ slightly from official EIA data reports.
Source: 2002 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, October 2002), and supporting databases. 2002 commercial and transportation electricity sales: EIA estimates based on Oak Ridge National Laboratory, *Transportation Energy Data Book 21* (Oak Ridge, TN, September 2001). 2002 prices: EIA, National Energy Modeling System run INBASE.D040904A. **Projections**: EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

Table C5. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Electric PowerSector[2]										
Power Only[3]										
Coal Steam	305.7	302.4	299.5	297.6	348.0	306.4	297.0	403.6	328.8	311.8
Other Fossil Steam[4]	132.5	102.2	101.5	100.7	97.5	93.9	92.1	95.5	92.7	91.4
Combined Cycle	81.0	126.6	130.3	130.8	180.0	201.4	206.7	200.7	235.8	237.1
Combustion Turbine/Diesel	122.7	130.4	128.6	128.2	162.2	162.5	158.7	176.1	181.6	169.1
Nuclear Power[5]	98.7	100.6	100.6	100.6	102.6	102.6	102.6	102.6	102.6	102.6
Pumped Storage	20.2	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	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	91.4	98.1	100.4	107.2	107.1	143.5	167.1	112.3	163.5	192.9
Distributed Generation[7]	0.0	0.5	0.7	0.6	8.4	9.7	8.9	13.8	15.4	14.0
Total	**852.3**	**881.2**	**882.0**	**886.2**	**1026.3**	**1040.4**	**1053.6**	**1124.9**	**1140.9**	**1139.2**
Combined Heat and Power[8]										
Coal Steam	5.2	5.2	4.6	4.6	5.2	4.6	4.6	5.2	4.6	4.6
Other Fossil Steam[4]	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Combined Cycle	29.4	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9
Combustion Turbine/Diesel	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
Renewable Sources[6]	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**41.4**	**44.9**	**44.3**	**44.3**	**44.9**	**44.3**	**44.3**	**44.9**	**44.3**	**44.3**
Total Electric Power Industry	**893.7**	**926.1**	**926.3**	**930.5**	**1071.1**	**1084.7**	**1097.8**	**1169.8**	**1185.2**	**1183.5**
Cumulative Planned Additions[9]										
Coal Steam	0.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
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	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5	43.5
Combustion Turbine/Diesel	0.0	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Renewable Sources[6]	0.0	4.3	4.3	4.3	4.7	4.7	4.7	4.8	4.8	4.8
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**	**57.1**	**57.1**	**57.1**	**57.5**	**57.5**	**57.5**	**57.6**	**57.6**	**57.6**
Cumulative Unplanned Additions[9]										
Coal Steam	0.0	2.9	0.7	0.0	50.4	10.6	3.7	107.1	34.1	19.8
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	6.7	10.4	10.9	60.0	81.5	86.8	80.8	115.9	117.1
Combustion Turbine/Diesel	0.0	10.7	8.8	8.1	43.8	44.9	39.7	61.6	64.0	52.2
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	2.1	4.4	11.2	10.7	47.1	70.7	15.7	67.0	96.3
Distributed Generation[7]	0.0	0.5	0.7	0.6	8.4	9.7	8.9	13.8	15.4	14.0
Total	**0.0**	**22.9**	**25.0**	**30.8**	**173.4**	**193.7**	**209.8**	**279.0**	**296.4**	**299.5**
Cumulative Total Additions	**0.0**	**80.0**	**82.0**	**87.9**	**230.9**	**251.2**	**267.3**	**336.6**	**354.0**	**357.1**
Cumulative Retirements[10]										
Coal Steam	0.0	7.4	8.7	9.8	9.2	11.6	14.2	10.4	12.7	15.5
Other Fossil Steam[4]	0.0	28.4	29.1	29.9	33.1	36.7	38.5	35.1	37.9	39.2
Combined Cycle	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Combustion Turbine/Diesel	0.0	10.3	10.2	10.0	11.6	12.4	11.0	15.6	12.5	13.2
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.0**	**47.9**	**49.8**	**51.5**	**55.8**	**62.6**	**65.6**	**62.9**	**64.9**	**69.7**

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

Net Summer Capacity[1]	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
End-Use Sector										
Combined Heat and Power[11]										
Coal	4.2	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Petroleum	1.0	1.6	1.6	1.6	2.3	2.4	2.4	2.4	2.4	2.4
Natural Gas	14.1	17.1	17.4	17.4	22.7	24.5	25.0	26.4	29.2	30.6
Other Gaseous Fuels	1.8	2.2	2.2	2.2	2.5	2.6	2.6	2.7	2.7	2.8
Renewable Sources[6]	4.2	5.6	5.6	5.6	7.5	7.5	7.5	8.3	8.3	8.3
Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Total	**25.5**	**31.0**	**31.2**	**31.3**	**39.6**	**41.5**	**42.0**	**44.2**	**47.1**	**48.6**
Other End-Use Generators[12]										
Renewable Sources[13]	1.1	1.4	1.4	1.4	1.9	2.0	1.9	2.5	2.7	2.8
Cumulative Additions[9]										
Combined Heat and Power[11]	0.0	5.5	5.8	5.8	14.1	16.0	16.5	18.7	21.6	23.1
Other End-Use Generators[12]	0.0	0.4	0.4	0.4	0.8	0.9	0.9	1.5	1.7	1.7

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capability.
[5]Nuclear capacity reflects operating capacity of existing units, including 3.9 gigawatts of uprates through 2025.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak-load capacity fueled by natural gas
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public(i.e., those that report NAICS code 22).
[9]Cumulative additions after December 31, 2002.
[10]Cumulative total retirements after December 31, 2002.
[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 C10 for more detail.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model estimates and may differ slightly from official EIA data reports.
Source: 2002 electric generating capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). **Projections**: EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

Table C6. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year)

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Production										
Dry Gas Production[1]	19.05	21.19	21.21	21.30	23.56	23.87	23.96	23.74	24.51	24.62
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	**3.49**	**4.74**	**4.77**	**4.79**	**6.55**	**6.82**	**6.86**	**7.28**	**8.05**	**7.92**
Canada	3.59	2.86	2.88	2.88	2.68	2.75	2.78	2.80	2.88	2.91
Mexico	-0.26	-0.30	-0.29	-0.29	-0.09	-0.07	-0.07	-0.02	0.04	0.04
Liquefied Natural Gas	0.17	2.17	2.19	2.21	3.96	4.14	4.15	4.50	5.12	4.98
Total Supply	**22.62**	**26.02**	**26.08**	**26.18**	**30.21**	**30.79**	**30.91**	**31.11**	**32.65**	**32.64**
Consumption by Sector										
Residential	4.92	5.55	5.55	5.54	5.96	5.95	5.94	6.13	6.11	6.11
Commercial	3.12	3.46	3.45	3.45	3.83	3.81	3.81	4.03	4.01	4.01
Industrial[3]	7.23	8.39	8.39	8.39	9.56	9.60	9.63	10.26	10.32	10.40
Electric Power[4]	5.55	6.66	6.72	6.82	8.56	9.12	9.20	8.36	9.80	9.68
Transportation[5]	0.01	0.06	0.06	0.06	0.10	0.10	0.10	0.11	0.11	0.11
Pipeline Fuel	0.63	0.70	0.70	0.70	0.82	0.84	0.84	0.84	0.87	0.88
Lease and Plant Fuel[6]	1.32	1.30	1.30	1.31	1.48	1.49	1.50	1.50	1.54	1.55
Total	**22.78**	**26.11**	**26.17**	**26.28**	**30.32**	**30.90**	**31.02**	**31.23**	**32.76**	**32.75**
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]	**-0.16**	**-0.09**	**-0.09**	**-0.09**	**-0.11**	**-0.11**	**-0.11**	**-0.11**	**-0.11**	**-0.11**

[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, 2002 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). 2002 consumption based on: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

Table C7. Oil and Gas Supply

Production and Supply	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Crude Oil										
Lower 48 Average Wellhead Price[1] (2002 dollars per barrel)	**24.54**	**23.64**	**23.64**	**23.64**	**25.61**	**25.87**	**25.60**	**26.86**	**26.85**	**26.84**
Production (million barrels per day)[2]										
U.S. Total	**5.62**	**5.96**	**5.95**	**5.95**	**4.97**	**4.98**	**4.98**	**4.63**	**4.66**	**4.65**
Lower 48 Onshore	3.11	2.61	2.61	2.61	2.20	2.20	2.20	2.04	2.04	2.04
Lower 48 Offshore	1.53	2.43	2.42	2.42	2.03	2.04	2.04	2.08	2.10	2.10
Alaska	0.98	0.92	0.92	0.92	0.74	0.74	0.74	0.51	0.51	0.51
Lower 48 End of Year Reserves (billion barrels)[2]	**19.05**	**18.42**	**18.41**	**18.41**	**16.17**	**16.21**	**16.19**	**15.04**	**15.11**	**15.09**
Natural Gas										
Lower 48 Average Wellhead Price[1] (2002 dollars per thousand cubic feet)	**2.95**	**3.40**	**3.43**	**3.44**	**4.15**	**4.27**	**4.31**	**4.43**	**4.48**	**4.49**
Dry Production (trillion cubic feet)[3]										
U.S. Total	**19.05**	**21.19**	**21.21**	**21.30**	**23.57**	**23.88**	**23.96**	**23.74**	**24.51**	**24.63**
Lower 48 Onshore	13.76	15.13	15.16	15.24	16.33	16.61	16.68	16.47	16.84	16.97
Associated-Dissolved[4]	1.60	1.41	1.41	1.41	1.23	1.23	1.23	1.17	1.17	1.17
Non-Associated	12.16	13.72	13.75	13.83	15.10	15.38	15.44	15.31	15.68	15.81
Conventional	6.14	5.94	5.97	5.99	6.07	6.17	6.20	5.92	6.01	6.02
Unconventional	6.02	7.78	7.78	7.84	9.02	9.21	9.24	9.38	9.67	9.78
Lower 48 Offshore	4.86	5.62	5.61	5.61	5.14	5.17	5.18	5.15	5.19	5.18
Associated-Dissolved[4]	1.05	1.64	1.64	1.64	1.34	1.34	1.34	1.43	1.43	1.43
Non-Associated	3.81	3.98	3.97	3.97	3.80	3.83	3.84	3.72	3.76	3.75
Alaska	0.43	0.45	0.45	0.45	2.10	2.10	2.10	2.12	2.47	2.47
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**180.03**	**201.99**	**202.01**	**202.07**	**198.74**	**198.26**	**198.39**	**191.26**	**189.91**	**189.99**
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)	**24.47**	**25.36**	**25.43**	**25.66**	**26.64**	**26.89**	**26.86**	**26.09**	**26.19**	**26.21**

[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 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: Energy Information Administration (EIA), *Petroleum Supply Annual 2002,* DOE/EIA-0340(2002)/1 (Washington, DC, June 2003). 2002 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2003/06) (Washington, DC, June 2003). Other 2002 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

Table C8. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Production[1]										
Appalachia	408	404	394	398	406	379	375	418	369	366
Interior	147	166	140	141	171	120	112	177	124	128
West	550	655	667	651	796	741	705	937	800	736
East of the Mississippi	504	517	492	496	528	470	460	546	467	467
West of the Mississippi	601	708	709	694	845	770	732	987	827	763
Total	**1105**	**1225**	**1201**	**1190**	**1373**	**1239**	**1193**	**1532**	**1294**	**1230**
Net Imports										
Imports	17	33	33	19	42	42	19	46	46	19
Exports	40	35	35	35	27	28	25	24	24	23
Total	**-23**	**-2**	**-2**	**-16**	**14**	**14**	**-6**	**22**	**22**	**-4**
Total Supply[2]	**1083**	**1223**	**1199**	**1174**	**1387**	**1253**	**1187**	**1554**	**1316**	**1226**
Consumption by Sector										
Residential and Commercial	4	5	5	5	5	5	5	5	5	5
Industrial[3]	63	66	66	66	68	67	67	69	68	68
of which: Coal to Liquids	0	0	0	0	0	0	0	0	0	0
Coke Plants	23	24	24	24	19	19	19	17	17	17
Electric Power[4]	976	1129	1105	1079	1296	1163	1096	1464	1227	1138
Total	**1066**	**1223**	**1199**	**1174**	**1388**	**1255**	**1188**	**1555**	**1317**	**1228**
Discrepancy and Stock Change[5]	**17**	**-0**	**-1**	**0**	**-1**	**-1**	**-1**	**-1**	**-1**	**-2**
Average Minemouth Price										
(2002 dollars per short ton)	17.90	16.71	16.79	17.02	16.51	15.83	16.00	16.58	15.58	15.87
(2002 dollars per million Btu)	0.87	0.82	0.81	0.82	0.81	0.77	0.78	0.82	0.76	0.77
Delivered Prices (2002 dollars per short ton)[6]										
Industrial	32.39	34.11	34.15	34.36	33.45	32.34	32.39	33.09	31.51	31.53
Coke Plants	51.27	53.70	53.92	53.95	50.45	50.62	50.71	48.44	48.65	48.67
Electric Power										
(2002 dollars per short ton)	25.88	24.55	27.68	36.86	24.16	35.17	52.03	24.33	37.75	55.49
(2002 dollars per million Btu)	1.25	1.22	1.37	1.82	1.21	1.74	2.57	1.22	1.88	2.74
Average	**26.80**	**25.63**	**28.56**	**37.07**	**24.98**	**35.25**	**50.89**	**24.98**	**37.57**	**54.06**
Exports[7]	40.44	36.44	36.36	36.42	34.13	33.82	34.82	32.23	31.93	33.60

[1]Includes anthracite, bituminous coal, lignite, and waste coal delivered to independent power producers. Waste coal deliveries totaled 11.1 million tons in 2002.
[2]Production plus net imports plus net storage withdrawals.
[3]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes all electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Balancing item: the sum of production, net imports, and net storage withdrawals minus total consumption.
[6]Sectoral prices weighted by consumption tonnage; weighted average excludes residential/ commercial prices and export free-alongside-ship (f.a.s.) prices.
[7]F.a.s. price at U.S. port of exit.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 data based on Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2002*, DOE/EIA-0121(2002/4Q) (Washington, DC, March 2003); EIA, *Annual Coal Report 2002*, DOE/EIA-0584(2002) (Washington, DC, November 2003); and EIA, AEO2004 National Energy Modeling System run INBASE.D040904A. **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

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

Supply Regions and Coal Types	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Northern Appalachia	**139.9**	**173.6**	**166.4**	**166.5**	**186.2**	**162.2**	**159.2**	**202.1**	**163.8**	**169.8**
Medium Sulfur (Premium)[1]	2.8	3.1	3.1	3.1	2.8	2.8	2.8	2.8	2.8	2.8
Low Sulfur (Bituminous)[2]	0.0	0.0	0.7	0.7	0.0	0.8	0.8	0.0	0.5	0.7
Medium Sulfur (Bituminous)[2]	66.6	86.4	75.8	75.6	86.9	78.3	77.2	92.1	81.3	79.9
High Sulfur (Bituminous)	59.4	75.7	81.1	81.5	88.1	74.7	72.9	98.4	73.7	80.8
High Sulfur (Gob)[3]	11.1	8.5	5.6	5.6	8.5	5.6	5.6	8.8	5.6	5.5
Central Appalachia	**249.1**	**218.8**	**214.1**	**218.5**	**208.8**	**205.7**	**204.9**	**206.1**	**194.6**	**185.5**
Medium Sulfur (Premium)[1]	34.0	34.5	34.5	34.5	29.1	29.1	29.1	23.6	23.3	25.6
Low Sulfur (Bituminous)	63.9	51.4	57.6	59.1	53.7	51.2	51.2	52.3	51.2	41.4
Medium Sulfur (Bituminous)	151.2	132.8	121.9	124.9	126.0	125.4	124.6	130.2	120.0	118.4
Southern Appalachia	**19.1**	**11.9**	**13.5**	**13.4**	**11.0**	**10.8**	**11.2**	**9.8**	**11.0**	**10.4**
Low Sulfur (Premium)[1]	4.6	4.8	4.8	4.8	1.1	1.1	1.1	1.0	0.9	0.9
Low Sulfur (Bituminous)	3.1	0.7	2.0	1.9	2.0	1.9	2.0	1.8	2.1	1.7
Medium Sulfur (Bituminous)	11.4	6.5	6.7	6.7	7.9	7.8	8.1	7.1	8.0	7.8
Eastern Interior	**96.0**	**113.1**	**98.0**	**98.0**	**121.9**	**91.2**	**84.9**	**127.7**	**97.5**	**101.6**
Medium Sulfur (Bituminous)	33.0	35.1	34.1	34.3	37.3	37.3	37.9	39.7	37.5	38.2
High Sulfur (Bituminous)	60.7	74.3	63.9	63.8	80.7	53.9	47.1	88.1	59.9	63.4
Medium Sulfur (Lignite)	2.3	3.8	0.0	0.0	3.9	0.0	0.0	0.0	0.0	0.0
Western Interior High Sulfur (Bituminous)	**1.9**	**1.7**	**1.6**	**1.7**	**1.5**	**1.8**	**1.8**	**1.9**	**0.3**	**1.5**
Gulf	**49.0**	**50.7**	**40.5**	**41.3**	**47.9**	**26.8**	**25.6**	**47.3**	**26.5**	**25.0**
Medium Sulfur (Lignite)	26.7	18.3	14.6	14.6	16.5	19.0	17.8	17.9	16.1	16.1
High Sulfur (Lignite)	22.3	32.4	25.9	26.7	31.4	7.8	7.8	29.5	10.4	8.9
Dakota Medium Sulfur (Lignite)	**31.1**	**32.9**	**29.4**	**29.5**	**30.3**	**24.1**	**21.5**	**32.9**	**20.5**	**20.7**
Powder/Green River	**410.2**	**512.7**	**513.0**	**496.3**	**628.1**	**580.3**	**544.7**	**751.5**	**630.7**	**571.8**
Low Sulfur (Bituminous)	0.0	1.0	1.0	0.8	1.1	1.1	0.6	0.0	0.0	0.8
Low Sulfur (Sub-Bituminous)	372.1	464.9	483.1	467.5	581.1	538.6	504.8	691.7	579.6	526.2
Medium Sulfur (Sub-Bituminous)	38.2	46.7	29.0	28.1	46.0	40.5	39.3	59.8	51.1	44.8
Rocky Mountain	**60.4**	**62.4**	**77.0**	**79.0**	**90.3**	**89.2**	**91.3**	**102.6**	**102.2**	**96.8**
Low Sulfur (Bituminous)	50.4	54.2	69.8	71.9	78.8	82.0	84.1	91.1	94.1	92.3
Low Sulfur (Sub-Bituminous)	10.0	8.2	7.1	7.0	11.6	7.2	7.2	11.5	8.1	4.5
Arizona/New Mexico	**41.7**	**41.8**	**41.6**	**40.2**	**41.6**	**41.9**	**41.8**	**44.9**	**41.0**	**41.5**
Low Sulfur (Bituminous)	23.0	22.7	24.4	24.9	17.8	18.3	19.0	21.5	18.6	18.7
Medium Sulfur (Bituminous)	1.8	8.3	8.3	4.6	9.8	9.8	9.8	9.4	9.8	9.8
Medium Sulfur (Sub-bituminous)	17.0	10.9	8.9	10.7	13.9	13.7	12.9	13.9	12.6	12.9
Washington/Alaska Medium Sulfur (Sub-Bituminous)	**7.0**	**5.3**	**5.6**	**5.6**	**5.4**	**5.6**	**5.6**	**5.4**	**5.6**	**5.6**

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

Supply Regions and Coal Types	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Subtotals: All Regions										
Premium Metallurgical[1]	41.4	42.4	42.4	42.4	33.0	33.0	32.9	27.3	27.1	29.4
Bituminous	526.2	550.7	549.0	552.2	591.5	544.2	537.1	633.6	557.0	555.4
Sub-Bituminous	444.2	536.1	533.6	518.9	657.9	605.7	569.8	782.3	657.1	594.1
Lignite	93.6	95.8	75.6	76.5	90.6	56.5	52.7	89.0	52.7	51.2
Low Sulfur	527.0	607.9	650.5	638.6	747.1	702.2	670.7	870.9	755.1	687.2
Medium Sulfur	423.0	424.6	372.0	372.2	415.8	393.4	386.7	434.8	388.7	382.7
High Sulfur	155.4	192.5	178.1	179.3	210.2	143.7	135.2	226.5	150.0	160.2
Underground	356.9	382.4	386.5	385.5	419.6	387.3	383.1	452.1	397.4	394.4
Surface	748.5	842.6	814.1	804.5	953.4	852.1	809.5	1080.1	896.4	835.6
U.S. Total	**1105.4**	**1225.0**	**1200.6**	**1190.1**	**1373.0**	**1239.3**	**1192.5**	**1532.2**	**1293.8**	**1230.1**

[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, Northern Tennessee.
Southern Appalachia: Alabama, Southern 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, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

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

Capacity and Generation	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Electric Power Sector[1]										
Net Summer Capacity										
Conventional Hydropower	78.29	78.69	78.69	78.69	78.68	78.68	78.68	78.68	78.68	78.68
Geothermal[2]	2.89	4.05	4.21	4.23	6.28	7.11	8.09	7.36	8.38	9.10
Municipal Solid Waste[3]	3.49	3.91	3.96	4.01	3.95	4.05	4.10	3.95	4.10	4.10
Wood and Other Biomass[4,5]	1.83	2.46	2.36	3.16	3.47	6.79	15.01	5.07	17.13	38.86
Solar Thermal	0.33	0.43	0.43	0.43	0.49	0.49	0.49	0.52	0.52	0.52
Solar Photovoltaic[5]	0.02	0.15	0.15	0.15	0.32	0.32	0.32	0.41	0.41	0.41
Wind	4.83	8.72	10.87	16.78	14.19	46.29	60.69	16.54	54.58	61.46
Total	**91.69**	**98.41**	**100.68**	**107.45**	**107.39**	**143.75**	**167.39**	**112.53**	**163.80**	**193.12**
Generation (billion kilowatthours)										
Conventional Hydropower	255.78	304.37	304.37	304.38	304.63	304.63	304.64	304.80	304.79	304.80
Geothermal[2]	13.36	23.54	24.83	24.93	41.95	48.67	56.23	50.84	58.90	64.30
Municipal Solid Waste[3]	20.02	28.09	28.45	28.82	28.44	29.24	29.63	28.50	29.70	29.70
Wood and Other Biomass[5]	8.67	24.21	28.78	30.03	30.79	43.22	92.59	34.56	106.87	251.14
Dedicated Plants	6.33	14.26	13.53	16.57	21.50	39.69	88.56	31.22	105.44	250.97
Cofiring	2.34	9.95	15.25	13.46	9.30	3.53	4.03	3.34	1.43	0.17
Solar Thermal	0.54	0.84	0.84	0.84	1.04	1.04	1.04	1.11	1.11	1.11
Solar Photovoltaic[6]	0.00	0.36	0.36	0.36	0.79	0.79	0.79	1.02	1.02	1.02
Wind	10.51	26.41	33.69	54.06	45.77	164.02	213.15	54.29	193.05	215.79
Total	**308.87**	**407.81**	**421.32**	**443.41**	**453.42**	**591.62**	**698.07**	**475.11**	**695.44**	**867.85**
End- Use Sector										
Net Summer Capacity										
Combined Heat and Power[7]										
Municipal Solid Waste	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Biomass	3.91	5.36	5.35	5.35	7.27	7.25	7.25	8.04	8.03	8.03
Total	**4.16**	**5.61**	**5.60**	**5.60**	**7.52**	**7.51**	**7.50**	**8.29**	**8.28**	**8.28**
Other End-Use Generators[8]										
Conventional Hydropower[9]	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.04	0.40	0.40	0.40	0.85	0.93	0.90	1.52	1.69	1.73
Total	**1.06**	**1.42**	**1.42**	**1.42**	**1.88**	**1.95**	**1.93**	**2.54**	**2.72**	**2.75**
Generation (billion kilowatthours)										
Combined Heat and Power[7]										
Municipal Solid Waste	1.84	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Biomass	28.16	36.65	36.60	36.59	47.79	47.71	47.69	52.31	52.25	52.22
Total	**30.00**	**38.75**	**38.70**	**38.69**	**49.89**	**49.81**	**49.79**	**54.41**	**54.35**	**54.32**
Other End-Use Generators[8]										
Conventional Hydropower[9]	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar Photovoltaic	0.09	0.86	0.86	0.86	1.84	2.00	1.94	3.25	3.60	3.67
Total	**4.20**	**4.97**	**4.97**	**4.96**	**5.95**	**6.11**	**6.05**	**7.35**	**7.71**	**7.78**

[1]Includes electricity-only and combined heat and power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes landfill gas.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2010.
[6]Does not include off-grid photovoltaics (PV). See Annual Energy Review 2002 Table 10.6 for estimates of 1989-2001 PV shipments, including exports, for both grid-connected and off-grid applications.
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors.
[8]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.
[9]Represents own-use industrial hydroelectric power.

Note: Totals may not equal sum of components due to independent rounding. Data for 2002 are model results and may differ slightly from official EIA data reports. Net summer capacity has been estimated for nonutility generators for AEO2004. 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: 2002 capacity: Energy Information Administration (EIA), Form EIA-860: "Annual Electric Generator Report" (preliminary). 2002 generation: EIA, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, October 2002). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

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

Sector and Source	2002	2010 Reference	2010 Carper Intl	2010 Carper Domestic	2020 Reference	2020 Carper Intl	2020 Carper Domestic	2025 Reference	2025 Carper Intl	2025 Carper Domestic
Residential										
Petroleum	104.0	110.6	110.6	110.6	107.4	107.5	107.5	104.7	104.8	104.9
Natural Gas	267.2	301.0	301.0	300.9	323.7	322.8	322.6	332.8	331.7	331.9
Coal	1.1	1.2	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Electricity	816.7	897.8	878.9	862.0	1010.7	935.1	889.7	1091.2	970.1	907.0
Total	**1189.0**	**1310.6**	**1291.6**	**1274.7**	**1443.0**	**1366.5**	**1320.9**	**1529.8**	**1407.7**	**1344.8**
Commercial										
Petroleum	52.6	66.9	67.0	67.0	70.8	71.1	71.2	72.6	73.1	73.2
Natural Gas	169.4	187.6	187.5	187.4	207.9	207.0	206.6	218.7	217.9	217.9
Coal	9.2	9.3	9.3	9.3	9.2	9.2	9.2	9.2	9.2	9.2
Electricity	778.0	930.8	912.1	894.9	1131.2	1044.6	995.3	1259.6	1116.7	1047.2
Total	**1009.1**	**1194.5**	**1175.9**	**1158.6**	**1419.1**	**1331.9**	**1282.4**	**1560.2**	**1416.9**	**1347.5**
Industrial[1]										
Petroleum	412.8	366.4	366.0	366.0	409.8	410.8	410.0	428.7	429.7	429.4
Natural Gas[2]	432.7	519.2	519.3	519.5	591.7	594.5	596.2	629.8	635.5	640.3
Coal	185.1	194.6	194.2	194.2	185.8	184.7	184.4	183.4	182.1	181.7
Electricity	640.0	709.4	696.3	683.5	814.7	753.6	717.0	898.9	798.2	747.3
Total	**1670.6**	**1789.6**	**1775.8**	**1763.3**	**2002.0**	**1943.6**	**1907.7**	**2140.7**	**2045.5**	**1998.7**
Transportation										
Petroleum[3]	1811.2	2198.2	2198.9	2198.6	2611.3	2610.5	2609.9	2829.1	2827.0	2826.6
Natural Gas[4]	35.2	41.0	40.9	41.2	49.9	50.5	51.0	51.4	53.4	53.9
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	14.2	16.6	16.3	16.0	19.8	18.5	17.7	22.3	20.0	18.8
Total	**1860.6**	**2255.7**	**2256.1**	**2255.8**	**2681.0**	**2679.5**	**2678.5**	**2902.7**	**2900.4**	**2899.3**
Total Carbon Dioxide Emissions by Delivered Fuel										
Petroleum[3]	2380.5	2742.1	2742.5	2742.2	3199.3	3199.9	3198.6	3435.0	3434.7	3434.1
Natural Gas	904.4	1048.8	1048.7	1049.0	1173.2	1174.8	1176.4	1232.7	1238.5	1243.9
Coal	195.4	205.0	204.6	204.6	196.1	195.0	194.8	193.7	192.4	191.9
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	2249.0	2554.6	2503.6	2456.6	2976.5	2751.8	2619.7	3271.9	2905.1	2720.2
Total	**5729.3**	**6550.5**	**6499.4**	**6452.4**	**7545.1**	**7321.5**	**7189.5**	**8133.4**	**7770.6**	**7590.3**
Electric Power[6]										
Petroleum	72.2	50.6	31.4	29.0	61.2	40.8	33.7	60.8	42.0	33.1
Natural Gas	299.1	358.5	361.4	366.9	460.5	490.4	495.0	450.0	527.0	521.1
Coal	1877.8	2145.4	2110.8	2060.7	2454.7	2220.7	2091.0	2761.1	2336.1	2166.0
Total	**2249.0**	**2554.6**	**2503.6**	**2456.6**	**2976.5**	**2751.8**	**2619.7**	**3271.9**	**2905.1**	**2720.2**
Total Carbon Dioxide Emissions by Primary Fuel[7]										
Petroleum[3]	2452.7	2792.7	2773.9	2771.2	3260.5	3240.7	3232.4	3495.9	3476.7	3467.2
Natural Gas	1203.4	1407.4	1410.1	1416.0	1633.8	1665.1	1671.4	1682.7	1765.5	1765.0
Coal	2073.2	2350.4	2315.4	2265.2	2650.8	2415.7	2285.8	2954.8	2528.5	2358.0
Other[5]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**5729.4**	**6550.5**	**6499.4**	**6452.4**	**7545.1**	**7321.5**	**7189.5**	**8133.4**	**7770.6**	**7590.3**
Carbon Dioxide Emissions (tons per person)	**19.8**	**21.2**	**21.0**	**20.9**	**22.5**	**21.9**	**21.5**	**23.4**	**22.4**	**21.8**

[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 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 2002 are model results and may differ slightly from official EIA data reports.
Sources: 2002 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2002,* DOE/EIA-0573(2002) (Washington, DC, October 2003). **Projections:** EIA, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.

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

Supply and Disposition	2002	Projections								
		2010			2020			2025		
		Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic	Reference	Carper Intl	Carper Domestic
Emissions										
Nitrogen Oxides (million tons)	4.39	3.48	1.81	1.80	3.66	1.70	1.70	3.72	1.70	1.70
Sulfur Dioxide (million tons)	10.19	9.62	5.33	5.32	8.95	3.31	3.28	8.95	2.84	2.86
From Coal	9.95	9.41	5.22	5.23	8.72	3.25	3.22	8.73	2.78	2.80
From Oil/Other	0.24	0.21	0.11	0.10	0.23	0.07	0.05	0.21	0.05	0.05
Mercury (tons)	50.81	52.60	24.00	24.00	53.50	10.00	10.00	54.60	10.00	10.00
Carbon Dioxide (million metric tons)	2248.9	2554.56	2503.62	2456.57	2976.48	2751.83	2619.74	3271.93	2905.06	2720.25
Allowance Prices										
Nitrogen Oxides (2002 dollars per ton)										
Regional/Seasonal	0.00	4347.54	0.00	0.00	4929.66	0.00	0.00	5114.85	0.00	0.00
East/Annual	0.00	0.00	1987.48	1992.57	0.00	1718.99	1665.24	0.00	1856.76	1791.73
West/Annual	0.00	0.00	1987.51	1992.60	0.00	1719.01	1665.26	0.00	1856.77	1791.75
Sulfur Dioxide (2002 dollars per ton)	108.61	150.41	905.76	898.22	258.59	1715.76	1867.84	173.48	2064.34	1792.45
Mercury (thousand 2002 dollars per pound)	0.00	0.00	16.56	16.55	0.00	63.52	55.52	0.00	68.60	55.35
Carbon Dioxide (2002 dollars per million metric ton)	0.00	0.00	1.27	6.04	0.00	5.78	14.60	0.00	7.31	16.67
Retrofits (gigawatts)										
Scrubber[6]										
Planned	2.26	20.20	20.20	20.20	23.05	23.05	23.05	23.05	23.05	23.05
Unplanned	0.00	1.60	53.46	51.50	1.60	114.17	106.49	1.60	126.74	122.72
Total	2.26	21.80	73.66	71.69	24.65	137.22	129.54	24.65	149.79	145.77
Nitrogen Oxides Controls										
Combustion	0.00	14.85	24.38	26.01	15.41	28.30	29.62	15.76	28.30	29.62
SCR Post-combustion	6.32	82.04	157.15	153.95	90.14	164.27	157.57	92.89	164.58	158.96
SNCR Post-combustion	0.00	11.43	8.87	9.34	16.75	11.97	10.84	22.81	14.10	13.27
Coal Production by Sulfur Category (million tons)										
Low Sulfur (< .61 lbs per million Btu)	527.04	607.94	650.50	638.60	747.05	702.19	670.68	870.88	755.06	687.17
Medium Sulfur	422.96	424.57	371.97	372.20	415.78	393.41	386.66	434.80	388.75	382.69
High Sulfur (> 1.67 lbs per million Btu)	155.38	192.53	178.11	179.27	210.16	143.73	135.18	226.54	150.00	160.19
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	2.38	18.37	18.14	0.00	9.01	8.95	0.00	4.86	4.73
Coal Characteristics										
SO_2 Content (lbs per million Btu)	1.86	1.89	1.81	1.85	1.82	1.68	1.71	1.78	1.66	1.79
Mercury Content (lbs per trillion Btu)	7.55	7.23	6.99	7.12	7.00	6.78	6.95	6.91	6.66	6.96
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	39.91	41.98	0.00	139.89	137.52	0.00	141.66	138.50
ACI Mercury Removal (tons)	**0.00**	**0.00**	**15.86**	**15.44**	**0.00**	**25.53**	**24.35**	**0.00**	**25.46**	**23.95**
Allowance Revenues (billion 2002 dollars)										
Nitrogen Oxides	0.00	2.06	3.72	3.73	2.33	2.92	2.83	2.42	3.16	3.05
Sulfur Dioxide	1.42	1.61	4.69	4.83	2.67	5.48	5.63	1.90	5.22	3.98
Mercury	0.00	0.00	1.00	0.89	0.00	1.23	1.10	0.00	1.15	1.10
Carbon Dioxide	0.00	0.00	3.19	14.84	0.00	15.92	38.24	0.00	21.25	45.34
Total	**1.42**	**3.67**	**12.59**	**24.28**	**5.00**	**25.55**	**47.80**	**4.32**	**30.77**	**53.46**

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 2002 are model results and may differ slightly from official EIA data reports.
Sources: Energy Information Administration, AEO2004 National Energy Modeling System runs INBASE.D040904A, INCA4P.D040904A, and INCA4PLO.D040904A.