4. Fuel Market and Macroeconomic Impacts

Coal Markets

Consumption, Production, and Prices

The imposition of new, more stringent emission caps on electricity power plants would affect coal consumption, total and regional production, prices, and industry employment. In general, the revised caps and the consequent need for introducing scrubbers, NO_x reduction equipment, and other measures necessary to achieve compliance with the caps would raise the cost of electricity from coal-fired power plants relative to those using other fuels, encourage fuel switching, and cause the level of coal-fired generation to be reduced. In all the analysis cases, impacts on national coal industry employment levels are projected to be negative relative to the reference case. The overall impacts depend on both the extent of the projected decline in coal demand and the types of coal expected to be used in the future mix of coal-burning capacity.

In the NO_x cap cases, the additional cost of adding and operating emission control equipment is projected to increase electricity prices slightly and reduce electricity sales by a small amount. The projected coal share of electricity generation by fuel and total projected coal-fired generation in the NO_x cap cases are essentially unchanged from the reference case projections for 2020. Minemouth coal prices in the NO_x 2005 and NO_x 2008 cases track each other closely and range from 5 to 30 cents per ton higher than in the reference case for most of the 2005-2020 period.

In the two primary SO_2 cap cases, slight reductions in coal-fired generation are projected through 2020, as other fuels replace coal. Coal mines that supply medium- or high-sulfur coal are projected to have production declines, leading to lower projected minemouth prices for coal from those sources relative to the prices projected in the reference case (Table 13). To meet the SO_2 emission caps, coal consumption is projected to shift dramatically to favor coal originating from the Powder River Basin (PRB) in Wyoming and Montana, where surface mines working thick coal seams currently achieve levels of labor productivity that are on the order of 6 to 10 times greater than those in many other regions. The resultant low minemouth price of PRB coal and its low sulfur content are projected to lead to additional consumption of PRB coal in the SO_2 cap cases relative to the reference case.

Table 13. Projected Minemouth Coal Prices, 2005-2020
(1999 Dollars per Short Ton)

Analysis Case	2005	2008	2010	2015	2020
Reference	14.76	14.00	13.69	13.37	12.84
NO_x Cap Cases					
NO_x 2005	14.88	14.21	13.99	13.38	12.94
NO_x 2008	14.82	14.11	13.94	13.44	12.95
SO_2 Cap Cases					
SO_2 2005	12.97	12.67	12.41	12.29	11.94
SO_2 2008	13.62	12.52	12.71	12.42	11.87
SO_2 Sensitivity	13.53	12.67	12.59	12.40	12.25
CO_2 Cap Cases					
CO_2 1990-7% 2005	14.78	14.19	13.77	12.94	12.55
CO_2 1990-7% 2008	14.82	14.27	13.72	12.89	12.54
CO_2 Sensitivity	14.88	14.39	13.96	13.03	12.60
Integrated Cases					
Integrated 2005	12.92	12.24	11.93	11.07	10.93
Integrated 1990-7% 2005	13.07	12.53	11.82	11.32	11.18
Integrated 2008	13.70	12.07	11.86	11.25	10.87
Integrated 1990-7% 2008	13.70	12.44	12.03	11.56	11.16
Integrated Sensitivity	14.11	13.50	12.97	12.16	11.99

Source: National Energy Modeling System, runs MCBASE.D121300A (reference), MCNOX05.D121300A (NO_x 2005), MCNOX08.D121300A (NO_x 2008), MCSO205.D121300A (SO_2 2005), MCSO208.D121300A (SO_2 2008), MCSO205H.D121300A (SO_2 sensitivity), FDC7B05.D121300A (CO_2 1990-7% 2005), FDC7B08.D121300A (CO_2 1990-7% 2008), FDC7B05H.D121300A (CO_2 sensitivity), FDPOL05.D121300A (integrated 2005), FDP7B05. D121300B (integrated 1990-7% 2005), FDPOL08.D121500A (integrated 2008), FDP7B08.D121500A (integrated 1990-7% 2008), and FDP7B05H. D121300A (integrated sensitivity).

Because PRB coal has a lower energy content per ton than the average coal now burned, more of it is needed to produce comparable amounts of electricity, and its minemouth price per ton reflects its lower energy value. As a result, the quantity of PRB coal consumed for electricity generation and its minemouth price are projected to increase over time in the SO_2 cap cases, rising above the projected levels in the reference case. The low projected minemouth price for PRB coal and the expected increase in its market share combine to reduce both the projected national average minemouth price and the delivered price of coal to electricity generators relative to the reference case projections.

Sustained growth in electricity demand over the forecast period is projected in the SO_2 cap cases, coupled with projected higher natural gas prices and steady declines in nuclear generation. As a result, continued small annual increases in coal-fired generation are expected in most years through 2020. Although some older coal plants are expected to be retired, plants with scrubbers and highly efficient, low-emitting advanced coal technology units are projected to be placed into service. Following sharp declines in the initial years of the forecast in the SO_2 cap cases, coal production east of the Mississippi River is projected to recover gradually, for consumption in plants that have been retrofitted with scrubbers or in advanced coal plants. Eastern coal has a relatively high energy content, which permits greater generation of electricity per ton of coal burned. In the SO_2 sensitivity case, lower projected allowance prices are expected to lead to approximately 52 gigawatts of scrubber retrofits, as compared with 127 gigawatts projected in the SO_2 2005 case.

In the CO_2 cap cases, substantial reductions in coal consumption are projected, with corresponding drops in the projections for coal production (Table 14). To continue using coal in the CO_2 cap cases, a power plant operator would have to pay for the coal and for the CO_2 allowances needed to cover the emissions that would result from burning it. In the CO_2 1990-7% 2005 case, the delivered price of coal in 2010 is projected to average $0.92 per million Btu, and CO_2 allowances are projected to cost $3.65 on a per million Btu basis. Thus, the effective cost of using coal is projected to be $4.57 per million Btu in 2010 and $4.41 per million Btu in 2020 in the CO_2 1990-7% 2005 case. The corresponding costs in the reference case are projected to be $1.05 and $0.98 per million Btu in 2010 and 2020, respectively.

In all the cases with CO_2 caps, continued use of coal is projected to be reduced sharply at many plants. When the allowance price is accounted for, the effective delivered price of coal is quadrupled relative to the reference case (Table 15). Although the average delivered price for coal on a Btu basis still is projected to be below that for natural gas (which has a lower carbon allowance fee), the higher efficiency of natural gas generation is expected to tip the balance away from coal generation in many regional markets.

As existing coal-fired power plants become uneconomical in the CO_2 cap cases, large blocks of capacity are projected to be retired and replaced by natural gas capacity. The combined effects of lower coal capacity and lower utilization of the remaining coal capacity is projected to reduce coal consumption for electricity generation to levels that are approximately one-third of those in the

Table 14. Projected Coal Production, 2005-2020
(Million Short Tons)

Analysis Case	2005	2008	2010	2015	2020
Reference	1,235	1,283	1,297	1,310	1,342
NO_x Cap Cases					
NO_x 2005	1,226	1,263	1,265	1,288	1,324
NO_x 2008	1,224	1,263	1,268	1,283	1,320
SO_2 Cap Cases					
SO_2 2005	1,268	1,296	1,283	1,317	1,346
SO_2 2008	1,262	1,304	1,310	1,324	1,359
SO_2 Sensitivity	1,249	1,286	1,295	1,311	1,336
CO_2 Cap Cases					
CO_2 1990-7% 2005	805	701	681	617	574
CO_2 1990-7% 2008	986	795	651	620	570
CO_2 Sensitivity	932	885	859	793	731
Integrated Cases					
Integrated 2005	821	827	793	725	663
Integrated 1990-7% 2005	816	727	721	655	574
Integrated 2008	988	824	799	720	660
Integrated 1990-7% 2008	998	828	655	635	565
Integrated Sensitivity	940	900	869	797	726

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

Table 15. Projected Delivered Coal Prices to Electricity Generators, 2005-2020
(1999 Dollars per Million Btu)

Analysis Case	2005	2008	2010	2015	2020
Reference	1.13	1.07	1.05	1.01	0.98
NO_x Cap Cases					
NO_x 2005	1.13	1.08	1.06	1.03	0.99
NO_x 2008	1.13	1.08	1.06	1.02	0.99
SO_2 Cap Cases					
SO_2 2005	1.05	1.01	0.99	0.96	0.93
SO_2 2008	1.05	1.01	1.00	0.97	0.93
SO_2 Sensitivity	1.10	1.05	1.02	0.99	0.96
CO_2 Cap Cases					
CO_2 1990-7% 2005	0.99	0.94	0.92	0.86	0.82
CO_2 1990-7% 2008	1.02	0.96	0.91	0.85	0.81
CO_2 Sensitivity	1.04	1.01	0.97	0.91	0.85
Integrated Cases					
Integrated 2005	0.97	0.95	0.92	0.85	0.80
Integrated 1990-7% 2005	0.96	0.92	0.90	0.84	0.78
Integrated 2008	1.00	0.93	0.91	0.84	0.80
Integrated 1990-7% 2008	1.00	0.92	0.87	0.84	0.77
Integrated Sensitivity	1.04	0.99	0.96	0.90	0.85
CO_2 Cap Cases (Adjusted)[a]					
CO_2 1990-7% 2005	4.06	4.73	4.57	4.26	4.41
CO_2 1990-7% 2008	3.04	3.73	4.46	4.31	4.37
CO_2 Sensitivity	3.47	3.44	3.58	3.52	3.71
Integrated Cases (Adjusted)[a]					
Integrated 2005	3.91	3.83	3.85	3.39	3.71
Integrated 1990-7% 2005	3.87	4.45	4.35	4.10	4.13
Integrated 2008	2.83	3.55	3.68	3.48	3.79
Integrated 1990-7% 2008	2.83	3.15	4.11	4.13	4.07
Integrated Sensitivity	3.46	3.48	3.56	3.42	3.80

[a]Adjusted prices reflect the addition of carbon allowance fees to the delivered coal prices shown in the upper section of the table.

Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, MCSO205H.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDC7B05H.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, FDP7B08.D121500A, and FDP7B05H.D121300A.

reference case projections. Total coal production is projected to decline at a slower rate than demand from the electricity generation sector, however, because consumption in other sectors (including industrial and coking coal and coal exports, which are not subject to carbon allowance fees) remains essentially unchanged from reference case values. With large reductions in coal-fired generation projected as a result of the carbon allowance fees, SO_2 emissions are projected to be well below the reference case caps, and no additional scrubber retrofits are expected. In the CO_2 sensitivity case, which assumes less stringent CO_2 emission caps, the lower projected carbon allowance fees are expected to lead to higher coal production than projected in the other carbon cap cases. However, minemouth coal prices are projected to be lower than in the reference case, reflecting overall production declines.

In the integrated cases, coal markets are affected primarily by the CO_2 and SO_2 caps. In these cases, carbon allowance fees are projected to result in greatly reduced demand for coal in the electricity generation sector, reducing the expected coal share of total generation by electricity generators and cogenerators in 2020 from 45 percent in the reference case to between 17 and 20 percent in the integrated cases. Total coal production in 2020 ranges from 42 percent to 49 percent of that projected in the reference case.

Natural Gas Markets

Introduction

Natural gas is an important fuel in all sectors of the U.S. economy other than transportation. In 1999, natural gas accounted for 23.7 percent of U.S. energy consumption, making it second only to petroleum in terms of total consumption. U.S. natural gas consumption totaled 21.4 trillion cubic feet in 1999, 0.1 trillion cubic feet less than the 1998 total. The largest user of natural gas is the industrial sector (including cogenerators), which consumed 44 percent of all gas delivered to consumers in 1999. Electricity generation (excluding cogenerators) accounted

Impacts on the Rail Industry

In addition to the substantial contraction of the U.S. coal industry projected in the CO_2 cases for this analysis, the U.S. rail industry, which has about 200,000 employees and derives considerable revenues from coal shipments, also would be greatly affected. In 1999, 751 million tons of the 1,099 million tons of coal produced in the United States (68 percent) was transported to consumers partly or entirely by rail. Coal freight provided Class I railroads with $7.7 billion in revenues (1999 dollars), or 22 percent of all freight revenue earned. Coal freight car loadings and ton-miles tend to be dominated by a handful of railroads. For the major coal-hauling railroads, coal represented 38 percent of all carloadings during 1999. The average revenue received by Class I railroads for hauling coal was $10.31 per ton (1999 dollars).[a]

The National Energy Modeling System does not project financial data for the rail industry in either the reference or analysis cases. On a qualitative basis, however, certain impacts are likely. Particularly in the cases that incorporate CO_2 caps, railroads and other shipping modes would be required to respond to reduced coal traffic and excess transportation capacity by making major, costly adjustments to routes, schedules, equipment, and employment levels. Decreases in coal traffic and increased competitive pressures would lead to lower freight rates and revenues. At the same time, the inefficiencies associated with the reduced scale of operation would increase unit costs of operation. Lower revenues, special charges, and increased unit costs would sharply reduce rail earnings until new sources of freight revenues were developed.

In this report, coal transportation rates, expressed in 1999 dollars per ton, are assumed to decline over time in response to productivity gains. They are also assumed to vary with fuel prices but otherwise to be invariant across cases despite reductions or increases in traffic along any given route. All modes of coal transportation have achieved significant efficiencies over the past 20 years and have been able to pass along a portion of the savings to shippers in the form of lower rates. New equipment, improved scheduling, maintenance, and operating procedures, and more efficient use of labor have reduced average revenues for coal shipments to 1.72 cents per ton-mile in 1998, nearly a 60-percent decline in real terms from 1981. In contrast, average rail revenues for shipments of transportation equipment and chemicals were 10.55 cents and 3.68 cents per ton-mile, respectively.[b] Already intense interregional competition among coal producers seeking to offer the lowest possible delivered cost is another key factor that has helped to push coal transportation prices to lower levels. As a result, it would appear that reducing coal transportation rates at a faster rate to preserve markets would represent a major challenge to railroad managers.

Data published by the American Association of Railroads indicate that labor costs (wages, plus wage supplements) represent nearly 40 percent of total freight operating expenses plus fixed charges for all Class I railroads. Fuel costs, materials and supplies, and equipment rentals are assigned weights of 7 percent, 5 percent, and 11 percent respectively.[c] Reductions in coal traffic that are not offset by increases in traffic for other commodities would be likely to lead to layoffs, reducing wage costs, and to the adoption of other measures to reduce operating costs. However, fixed charges such as depreciation, interest, and taxes would then be distributed over a smaller traffic base, placing upward pressure on rates. Replacing coal traffic with other commodities would be difficult. For example, in 1998 coal accounted for four times more carloads than either the second-place commodity, transportation equipment, or the third-place commodity, chemicals.[b] Both commodities use shipping routes and equipment that are quite different from those for coal.

Progressively deregulated since the Staggers Rail Act of 1980, railroads have made substantial progress in improving productivity and reducing real costs by investing in new and more powerful locomotives, improved maintenance of main-line rights of way, and more efficient use of labor. A major contribution to achieving the joint goals of lower costs and maintenance of service has been made through a number of mergers over the past decade. Mergers have resulted in the emergence of four major railroad companies—two in the East (CSX and Norfolk-Southern) and two in the West (Burlington Northern-Santa Fe and Union Pacific-Southern Pacific). In 1999, Burlington Northern-Santa Fe received 23.2 percent of all commodity revenues from coal, and Union Pacific-Southern Pacific received 20.7 percent.[a]

The adoption of CO_2 emission restrictions is projected to result in a reduction in domestic coal traffic handled by the railroads. As suggested by the results of the CO_2 cap and integrated cases in this analysis, reductions in coal traffic could range from moderate to severe. In all

(continued on page 39)

[a]Source: Association of American Railroads, Freight Commodity Statistics.
[b]Source: Association of American Railroads, “The Rail Transportation of Coal” (January 2000).
[c]Source: Association of American Railroads, AAR Railroad Coal Indexes (September 2000).

Impacts on the Rail Industry (Continued)

the cases with CO_2 caps assumed, western coal, particularly subbituminous coal from the Powder River Basin, is projected to be most severely restricted, because of its dependence on long-distance rail transportation to reach its markets in locations up to 2,000 miles away.

Because the CO_2 reduction cases analyzed in this study project heavier losses in coal production for western than for eastern coalfields, and because much of the production from western coalfields is shipped over long distances to midwestern and eastern markets to satisfy demand for low-sulfur fuel, it is likely that the burden of reduced coal transportation revenues would fall most heavily on railroads in the West—particularly on the Burlington-Northern and Union Pacific systems, which now include the St. Louis Southwestern, the Chicago & Northwestern, the Denver & Rio Grande Western, the Southern Pacific, and the Atchison, Topeka & Santa Fe railroads.

Lignite production in Texas, Louisiana, and North Dakota is also expected to be severely reduced by CO_2 emission restrictions, but the effect on rail revenues is expected to be minor. Because of its inherently low heat content, lignite is predominantly consumed at or close to the place of mining. Although the projected losses of coal production in the individual CO_2 reduction cases are proportionately and absolutely less for Appalachian coal fields than for the Powder River Basin, the two eastern rail systems (CSX and Norfolk Southern) are also highly dependent on coal revenue. In the more severe CO_2 reduction cases, Appalachian coal production could be reduced by one-third to one-half, with potentially serious financial consequences for the eastern rail carriers.

for 16 percent of total consumption in 1999, and the residential and commercial sectors accounted for 24 percent and 16 percent, respectively.

The vast majority of the natural gas consumed in the United States is produced domestically. In 1999, the U.S. natural gas industry produced 18.7 trillion cubic feet, providing 87 percent of total gas consumption. Relative to other fuels, natural gas is second only to coal in domestic production. In 1999 it accounted for 35 percent of the fossil fuels produced in the United States, as measured by energy content. Production of natural gas is concentrated in the central regions of the country, and an expanding system of pipelines allows gas produced along the Gulf Coast to be consumed in the Midwest and in the Northeast. The other element of gas supply is imports. While the United States exported natural gas to Mexico in 1999, it was a net importer from Canada, importing 3.4 trillion cubic feet in 1999. A small amount of liquefied natural gas (LNG) is also imported from overseas, primarily from Algeria. In 1999, gross imports of LNG accounted for less than 5 percent of all U.S. natural gas imports and less than 1 percent of total consumption. By 2020 LNG imports are expected to reach 0.77 trillion cubic feet, or about 13 percent of total gas imports.

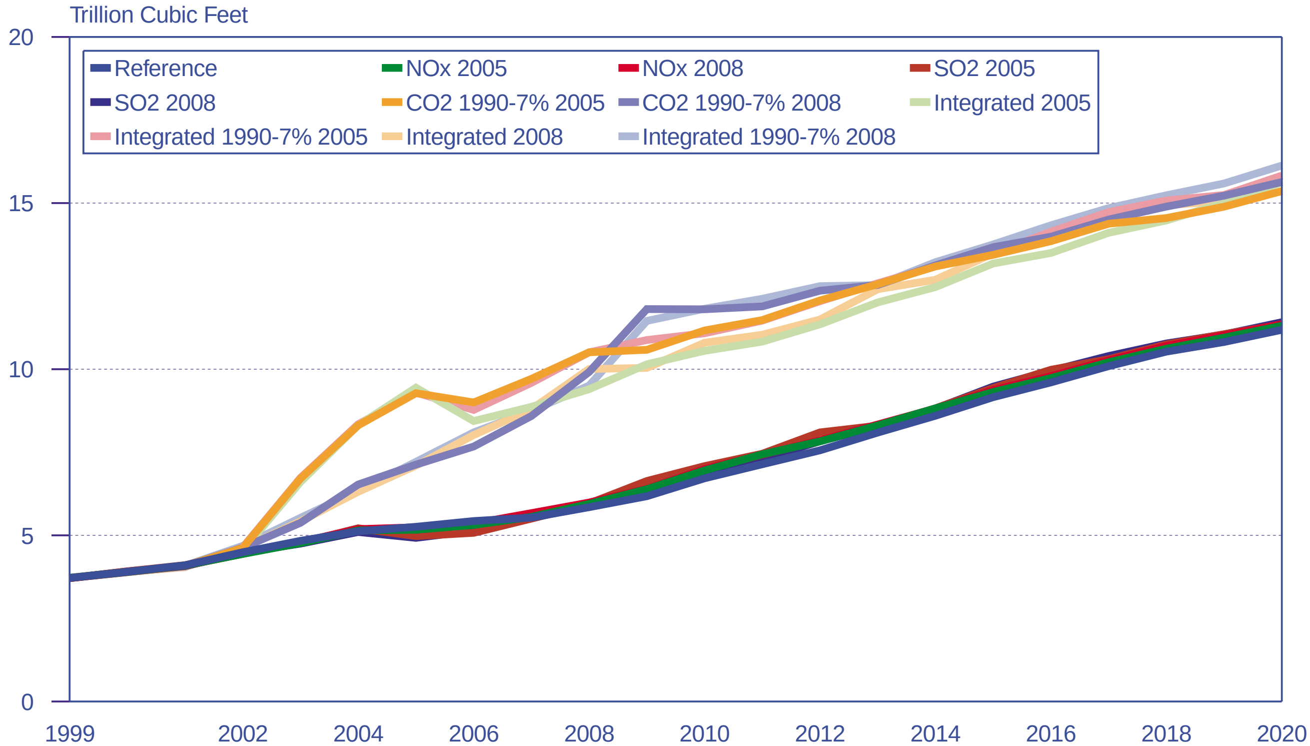
Over the next 20 years, the role of natural gas in U.S. energy markets is expected to increase as its use in the electricity generation sector grows. In the reference case for this analysis, total natural gas consumption is projected to grow to 34.6 trillion cubic feet in 2020, a 57-percent increase over projected consumption in 2000. With total energy use projected to grow by only 30 percent over the same interval, the share provided by natural gas is expected to increase. The largest component of the projected increase in gas consumption in the reference case is the electricity generation sector, which is expected to grow by 5.4 percent per year over the next two decades, as compared with roughly 1-percent annual growth in gas consumption projected for the residential, commercial, and industrial sectors.

The integrated, multi-emission strategies proposed to reduce emissions of NO_x, SO_2, and especially CO_2 are expected to have significant impacts on domestic natural gas consumption, production, and prices. Although the proposed caps are limited to the electricity generation sector, changes in fuel use for power generation would be expected to have significant impacts on the natural gas market as a whole. In the SO_2 and NO_x cap cases, the natural gas market is projected to change only slightly from the reference case, with slightly higher projections for domestic production and consumption in the SO_2 cap cases. Although there are some differences from the reference case projections in these cases, they are minor by comparison with the results of the CO_2 cap cases and the integrated cases, which also include CO_2 caps. Therefore, the discussion that follows concentrates on the CO_2 and integrated cases. The projections for natural gas in the CO_2 cap cases essentially mirror the results of the integrated cases, as the electricity sector switches from coal to natural gas to reduce CO_2 emissions.

Consumption

When CO_2 emission caps are assumed, natural gas consumption is projected to be higher than reference case levels because of higher demand in the electricity generation sector (Figure 17). In the integrated 2005 case, the volume of gas expected to be used for electricity generation increases by more than 5.5 trillion cubic feet (142 percent) from 2000 to 2005, as compared with a corresponding increase of 1.4 trillion cubic feet (35 percent) in the reference case. By 2005, the projection for power

Figure 17. Projected Natural Gas Consumption for Electricity Generation, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05. D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

plant use of natural gas in the integrated 2005 case is about 4.2 trillion cubic feet higher than in the reference case. The projected difference between the reference case and the integrated 2005 case narrows to 3.8 trillion cubic feet in 2010, then expands to 4.4 trillion cubic feet in 2020.

The projection for natural gas use by power generators in 2005 in the integrated 2008 case is 2.3 trillion cubic feet (25 percent) lower than in the integrated 2005 case. By 2010, however, the projection is higher in the integrated 2008 case than in the integrated 2005 case, and it continues to be higher for the rest of the forecast period. In the integrated 2008 case, natural gas consumption for electricity generation is projected to grow by only 3.2 trillion cubic feet between 2000 and 2005, but by 2020 the projections for gas use in the power generation sector are nearly the same in these two integrated cases. The projected increases in natural gas consumption in the cases that include CO_2 caps, relative to the reference case, are sensitive to the assumed levels of the emission caps. For example, in the integrated sensitivity case, natural gas consumption for electricity generation is projected to reach 7.8 trillion cubic feet in 2005, 2.6 trillion cubic feet higher than projected in the reference case but 1.5 trillion cubic feet lower than projected in the integrated 1990-7% 2005 case.

Total natural gas consumption is not expected to increase as rapidly as its use for electricity generation in the integrated cases. Because the projected increase in demand for natural gas in the power generation sector is expected to result in higher gas prices, consumption in other sectors of the economy is projected to be lower than projected in the reference case. In general, facing higher prices for natural gas, commercial and industrial users are expected to consume less natural gas than projected in the reference case, either increasing conservation or switching to other fuels. The projected second-order effects of demand from other sectors vary from case to case, based on the level of price increase. In general, however, demand for natural gas in the non-electricity sectors is quite inelastic, and the projected change in natural gas prices between the cases leads to only a limited change in the volumes expected to be used. In the integrated 2005 case, combined commercial, residential, and industrial consumption is projected to be 19.9 trillion cubic feet in 2020, compared with 15.6 trillion cubic feet projected to be consumed for electricity generation. In contrast, commercial, residential, and industrial use in the reference case is estimated to be nearly 0.4 trillion cubic feet higher, at 20.3 trillion cubic feet in 2020. In the integrated cases, higher gas prices and reduced use are projected for the commercial, residential, and industrial sectors, which are not included in the emission caps. The size of the reductions in demand from the non-electricity sectors is dwarfed, however, by the projected increases in gas use for electricity generation, and therefore total natural gas demand is higher when carbon emissions are reduced.

Supply

To meet the expected growth in demand for natural gas, both domestic production and imports are projected to increase above the reference case levels in the integrated cases. In the reference case, both imports and domestic production of natural gas are projected to grow over time, driven by a comparative price advantage for natural gas compared with petroleum and by continued economic growth. By 2020, domestic production is expected to increase by 54 percent, or 10.2 trillion cubic feet, from current levels. Over the same interval, net imports are expected to grow by 66 percent, or 2.3 trillion cubic feet, with most of the growth coming from an increase in imports from Canada. Mexico is expected to remain a net importer of natural gas from the United States in the reference case, and net U.S. LNG imports are projected to increase from 0.1 trillion cubic feet in 2000 to 0.8 trillion cubic feet in 2020.

Figure 18 shows the projected growth in natural gas supply by case between 1999 and 2020. Natural gas supply is projected to increase more rapidly in the integrated cases than in the reference case, as domestic producers are expected to respond to the higher prices associated with increased demand in the power generation sector. The most rapid projected growth in supply is seen in the integrated 2005 cases, but by 2020 natural gas supply is projected to be between 38.5 and 39.0 trillion cubic feet in the cases that include CO_2 emission caps.

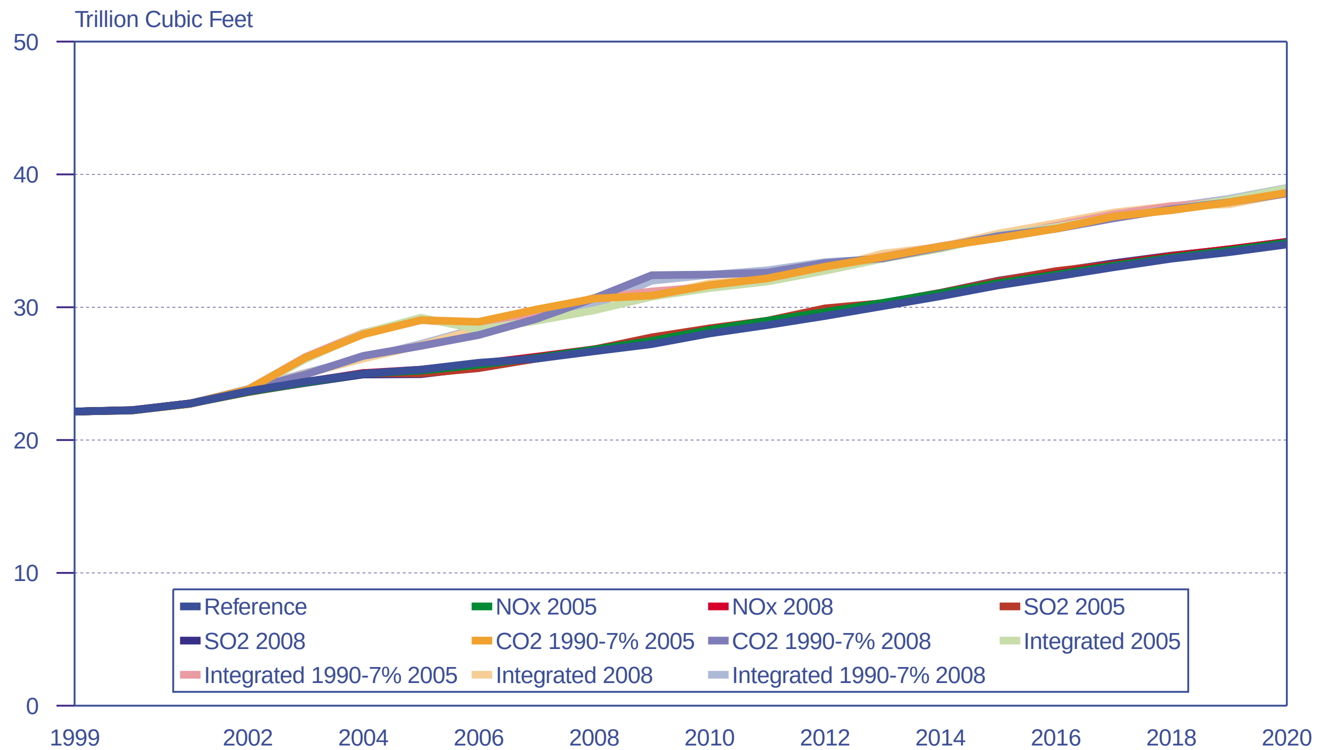
Domestic Production

The projected growth in natural gas production in the reference case is much more rapid than has been seen in recent years. Since 1988, the volume of gas produced domestically has fluctuated between 18 and 20 trillion cubic feet per year. In the reference case, domestic production is expected to expand from 18.6 trillion cubic feet in 2000 to 28.8 trillion cubic feet in 2020. Growth is expected to be fastest in the interval between 2010 and 2015, when annual domestic production is projected to grow by 3.1 trillion cubic feet.

In the cases that include CO_2 emission caps, the projected growth in domestic gas production is even stronger than in the reference case. For example, in the integrated 2005 case, domestic production is projected to grow by 5.1 trillion cubic feet between 2000 and 2005, as compared with 2.1 trillion cubic feet in the reference case. By 2020, however, the projected level of domestic production is only 2.4 trillion cubic feet higher in the integrated 2005 case than in the reference case, because natural gas production after 2005 is projected to increase more rapidly in the reference case than in the integrated 2005 case.

In the integrated 2008 case, gas production is not expected to grow as rapidly as in the integrated 2005 case. Between 2000 and 2005, production in the integrated 2008 case grows by only 3.2 trillion cubic feet, 1.8

Figure 18. Projected Total U.S. Natural Gas Supply, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

trillion cubic feet less than projected in the integrated 2005 case. By 2010, however, annual production in the integrated 2008 case is projected to be 25.5 trillion cubic feet, 0.4 trillion cubic feet higher than projected in the integrated 2005 case. By 2020, projected production in the integrated 2008 case is 0.3 trillion cubic feet higher than in the 2005 case. Earlier, sharper production increases in the 2005 case are expected to lead to a poorer reserve position in the first decade of the projection. Earlier and stronger shifts to renewable technologies in the integrated 2005 case cause projected natural gas consumption, and therefore production, in the later years of the forecast to be higher in the integrated 2008 case than in the integrated 2005 case.

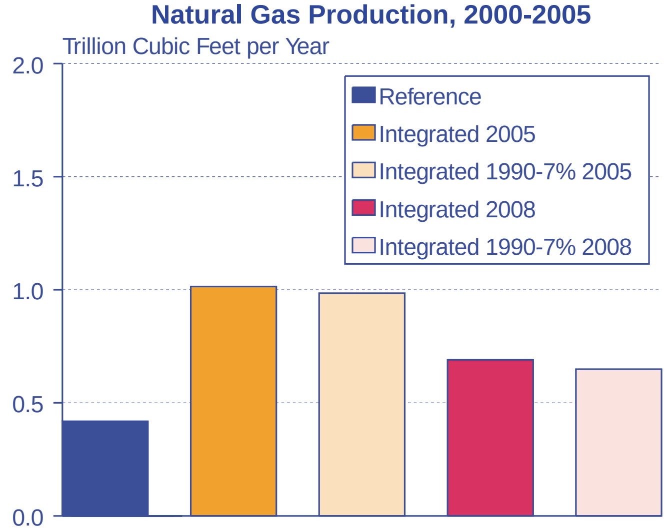
Over time, a much larger volume of gas is expected to be withdrawn from the domestic resource base in the cases with CO_2 emission caps than in the reference case. For example, by 2005, cumulative domestic production (from 2000) in the integrated 2005 case is projected to be 6.4 trillion cubic feet higher than projected in the reference case—an amount equivalent to approximately 4 months of production at current levels. By 2020, the difference in cumulative dry gas production between the integrated 2005 case and the reference case is projected to increase to 36.6 trillion cubic feet, about twice the volume of current production in a typical year. In 2005, cumulative production in the integrated 2005 case is projected to be 4.6 trillion cubic feet higher than in the integrated 2008 case. Although production is generally higher in the integrated 2008 case each year after 2005, cumulative production in 2020 is projected to be lower than in the integrated 2005 case.

Meeting the gas production requirements projected in the cases with stringent CO_2 caps in 2005 would be a challenge for the industry. Production increases of the magnitude projected here have not been seen for many years. The increase in production projected in the integrated 2005 case from 2000 to 2005, at 5.1 trillion cubic feet, is considerably stronger than the recent trend in gas production, which has been essentially flat through most of the 1990s. The most recent period of comparable growth was from 1965 to 1970, when domestic gas production increased by 5.7 trillion cubic feet. Although higher prices would give producers additional revenue, increasing natural gas production by the levels required in the cases with CO_2 emission caps would require considerable investment and effort on the part of the domestic natural gas industry.

On an annual basis, the projected increases in production are far greater than those seen in recent years. Figure 19 shows projected average annual growth in domestic natural gas production between 2000 and 2005 in the reference case and in the integrated cases. The growth rates projected in the two cases with 2005 reduction targets average 1.0 trillion cubic feet per year. The strongest annual growth in natural gas production estimated in the integrated 2005 case is in 2003, when production is projected to grow by 1.9 trillion cubic feet. The projected growth in 2003 is slightly higher in the integrated 1990-7% 2005 case, at 2.0 trillion cubic feet. (Smaller annual increases in production are projected in the integrated cases after 2003, when increases in demand are also expected to slow.) Historically, the largest annual increase in domestic natural gas production was 1.38 trillion cubic feet in 1984, but that increase followed extremely low production in 1983 and therefore can be seen in part as a return to an existing growth trend rather than a shift to a higher production level. During the sustained period of rapid growth between 1965 and 1970, the peak annual increase in natural gas production was 1.34 trillion cubic feet in 1969. The rate of growth projected in the integrated 2005 case during the first 5 years of the projection is unprecedented.

Several issues would need to be addressed for the domestic natural gas industry to meet the high production levels projected in this analysis. One is investment. Lower energy prices in recent years have led to decreases in investment and drilling activity, which have only recently begun to rebound as a result of higher prices for oil and gas. Stimulating additional drilling in the future will require significant additional investment, which is unlikely to be made unless the industry foresees a prolonged period of higher revenues. Given the projections of future domestic production in the integrated cases, however, it is likely that investors would recognize that limits on CO_2 emissions would lead to higher demand for natural gas—and higher prices—for an extended period. In response to those expectations, additional funds are expected to be made available to the industry, providing the necessary capital for

Figure 19. Projected Annual Change in Domestic Natural Gas Production, 2000-2005



Source: National Energy Modeling System, runs MCBASE.D121300A, FDPOL05.D121300A, FDP7B05.D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

additional investment in drilling rigs and field development. In contrast, short-term price increases in the early and mid-1990s were not seen as sustainable in the longer term and, therefore, have not led to more drilling.

Under any circumstances, bringing on the number of drilling rigs needed to meet the levels of demand projected in this analysis would be a challenge. Historically, the number of available rigs declined from more than 5,000 in 1982 to fewer than 1,500 in the late 1990s. In the reference case projections, the number of rigs needed is expected to increase by 304 (17 percent) between 2000 and 2005, and in the integrated 2005 case the projected increase is 541 rigs (31 percent) over the same period. However, the industry has shown that it can react quickly to sustained higher prices. Between 1979 and the peak in 1982, the number of oil and gas drilling rigs grew by more than 2,300, an increase of more than 80 percent in a 3-year period.

New oil and gas development technologies are expected to play a role in increasing gas supplies in the reference case. However, because the integrated cases (and especially the integrated 2005 cases) are expected to require rapid production increases in the early years of the projections, they would have to depend more heavily on existing technology and resources, and production costs are projected to be higher in those cases. For example, in the cases that assume CO_2 emission caps in 2005, more natural gas production is expected from offshore fields and unconventional resources than in the reference case. Production from these sources is relatively expensive based on current technology. Thus, the increased production is projected to be more costly than that in the reference case, with corresponding increases in the prices paid by natural gas users. When the CO_2 caps are assumed to go into effect in 2008 rather than 2005, the projected increases in production are delayed accordingly, allowing the time needed for new technologies and resources to come into play and slowing the projected price increases.

Although increasing production capacity is a challenge for the industry, in the long term there are adequate resources to allow production to expand as projected in the most stringent cases in this analysis. The forecasts assume that domestic resources of economically recoverable gas are roughly 1.2 quadrillion cubic feet. In the reference case, cumulative dry gas production from 2000 through 2020 is estimated to be 491 trillion cubic feet, compared with 528 trillion cubic feet in the integrated 2005 case. The additional 37 trillion cubic feet of production over the forecast period represents about 3 percent of the current estimated resource base. Therefore, the difference in the absolute levels of depletion of natural gas resources does not seem to preclude the expansion of gas production projected in the integrated 2005 case.

Imports

Canadian imports make up nearly all the projected increase in imports in the reference case, growing by a projected 2 trillion cubic feet over the next 20 years to a total of 5.5 trillion cubic feet in 2020. (The projections include growth in Canadian imports as a result of increased gas production in Alaska. New Alaskan gas that is not shipped directly to the lower 48 States is used in Canada, freeing up additional Canadian gas for export to the United States.) In the integrated 2005 case, Canadian imports are projected to grow by 2.6 trillion cubic feet—to 6.0 trillion cubic feet in 2020—in response to higher natural gas prices in the United States, and one-half of that increase is expected to occur by 2005.

Higher U.S. gas prices in the integrated 2005 case are also expected to stimulate net LNG imports, which are projected to increase to 1.3 trillion cubic feet by 2020—540 billion cubic feet higher than projected in the reference case. Although projected LNG imports are higher in the integrated cases, LNG remains a relatively small source of gas supply. The projected increase in LNG imports is limited even in the integrated 2005 case, because even with higher prices, additional expansion of LNG capacity is not likely to be economically viable, based on estimates of world supplies and existing technology. Stronger demand in the integrated case also is expected to reverse the flow of gas between the United States and Mexico. In the reference case, 176 billion cubic feet of natural gas is projected to be exported from the United States to Mexico in 2005. In the integrated 2005 case, however, net imports of natural gas from Mexico are expected to total 300 billion cubic feet in 2005, increasing to 360 billion cubic feet in 2020.

In order for imports to the lower 48 States to reach their projected levels in the cases with CO_2 emission caps, the import transportation infrastructure would have to be expanded more rapidly than projected in the reference case. For LNG, the higher import levels projected in the cases with CO_2 emission caps would only require more intensive use of existing regasification plants. In contrast, increasing imports from Canada and Mexico above the levels projected in the reference case would require additional pipeline and other infrastructure development by 2005 and continuing infrastructure development in Canada through 2020. Constructing the infrastructure necessary to meet the demand for natural gas imports projected in the integrated cases would require investment in pipelines and other infrastructure technology. Building the additional pipeline capacity that would be needed to allow an additional 430 billion cubic feet of gas across the Canada-U.S. border (beyond the 730 billion cubic feet of new capacity projected to be needed in the reference case after 1999) to be imported to the lower 48 States by 2005 in the integrated 2005 case would present a challenge to the industry that would require careful planning.

Using the past as a guide, the changes in production and imports that would be needed to meet the projected supply requirements in the CO_2 cap cases are large; however, the required growth is expected to be accompanied by higher projected prices. Thus, although meeting the projected requirements in the analysis cases that include CO_2 emission caps would require significant effort on the part of domestic producers and importers, primarily in the cases with 2005 CO_2 caps, the higher prices projected in those cases are expected to provide the necessary incentives for the industry to add capacity.

Pipeline Capacity

To meet the increased demand projected in the CO_2 cap cases, interstate pipeline capacity is also projected to increase. Additions to existing pipeline capacity are projected in all the cases, but more rapid expansion is expected in the cases with CO_2 emission caps. Between 2000 and 2005, interstate pipeline capacity (defined as the sum of the pipeline volumes crossing State borders) is projected to grow by 4.7 trillion cubic feet (5.1 percent) in the reference case and by 5.4 trillion cubic feet (4.5 percent) in the integrated 2005 case. More rapid growth in pipeline capacity is projected to continue in the integrated case, with the expected addition of 23.3 trillion cubic feet (21 percent) to interstate capacity between 2005 and 2020, as compared with 14.5 trillion cubic feet (13 percent) projected in the reference case over the same interval.

The strongest annual growth in pipeline capacity in the reference case is projected for 2001, at 2.9 trillion cubic feet. The projected increase is based on recently completed projects and the expected completion of projects currently under way, including the Alliance Pipeline running from Canada to the Midwest and the Maritimes / Northeast and Portland Natural Gas Transmission System pipelines running from Canada to the northeastern United States.

Except for the early increase projected for 2001, interstate capacity is projected to grow by 1.84 trillion cubic feet or less each year in the reference case. Greater annual increases are projected in the integrated 2005 case between 2010 and 2020, with the highest annual growth expected in 2014 at 2.1 trillion cubic feet.

The greatest single-year increase in interstate natural gas pipeline capacity in recent years was in 1992, when 1.6 trillion cubic feet of capacity was added. The strong short-term growth in capacity projected in the reference case, including the projected increase of 2.9 trillion cubic feet in 2001, is based on existing projects that are already completed or underway. These projects show how the industry is able to respond to the increased need for pipeline capacity. None of the projected annual increases after 2005 exceed the growth rate resulting from the projects that are currently underway; however, pipeline capacity expansion can require several years of lead time.

Prices

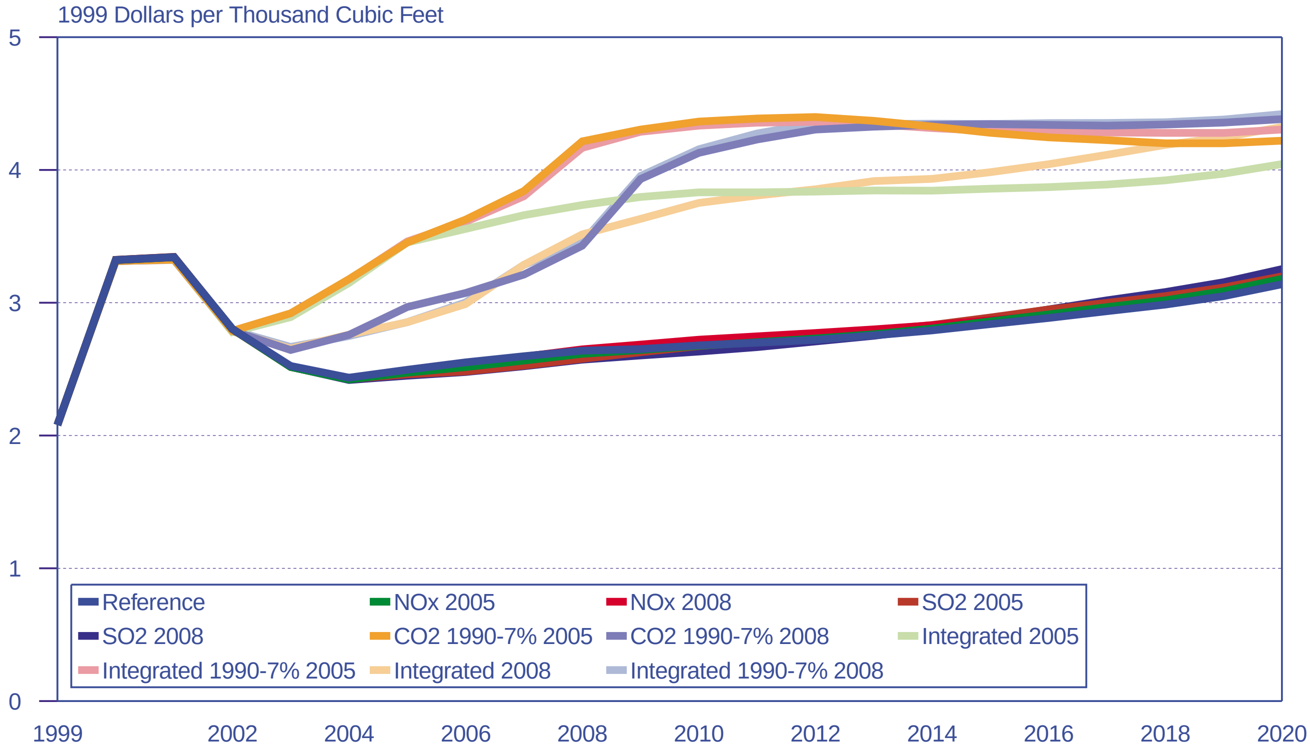
The increased demand for natural gas projected in the cases that include CO_2 emission caps is expected to result in higher prices. In the reference case, the average lower 48 wellhead price of natural gas is projected to be $2.49 per thousand cubic feet in 2005 (1999 dollars), rising to $3.14 per thousand cubic feet in 2020. In the reference case, natural gas wellhead prices of $3.32 and $3.34 per thousand cubic feet are projected for 2000 and 2001, respectively. Although current prices are high, the forecast is based on yearly averages and is designed to capture long-term trends in prices rather than higher prices that might stem from short-term market conditions. However, higher prices in the short term could lead to lower prices in later years of the projections, due to the effects of increased drilling and the resulting higher levels of reserves.

Only minor changes from the gas prices projected in the reference case are expected in the NO_x and SO_2 cap cases. In the CO_2 cap and integrated cases, however, prices are projected to be much higher than in the reference case as a result of the projected rapid increases in natural gas demand. In general, prices are expected to be higher in the 2005 cap cases than in the 2008 cap cases in the years immediately after the caps are assumed to be imposed.

The projected changes in prices from 2000 to 2020 vary by case (Figure 20). Projected wellhead gas prices in the cases with CO_2 caps rise more rapidly than projected in the reference case and end up considerably higher. In the integrated 2005 case, the wellhead price of natural gas in 2005 is projected to be $3.45 per thousand cubic feet, or $0.96 per thousand cubic feet higher than projected in the reference case. The projected prices in the integrated 2005 case are also higher than those in the reference case in 2020, by $0.91 per thousand cubic feet.

By the end of the forecast period, the natural gas prices projected in the integrated 2008 case are higher than those in the integrated 2005 case. In 2010, prices in the integrated 2008 case are expected to average $3.75 per thousand cubic feet (compared with $3.83 in the integrated 2005 case), rising to $4.32 per thousand cubic feet in 2020 (compared with $4.04 in the integrated 2005 case). The differences are due in part to the continued stronger demand from power generators expected in the integrated 2008 case. Higher prices earlier in the integrated 2005 case are also expected to improve the reserve position and reduce the cost of production in the later years of the forecast. The projected prices in the reference case remain within the historical range, but those in the cases that assume CO_2 caps are higher than they have been in the past, exceeding the 1983 average

Figure 20. Projected Domestic Wellhead Natural Gas Prices, 1999-2020



Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCNOX08.D121300A, MCSO205.D121300A, MCSO208.D121300A, FDC7B05.D121300A, FDC7B08.D121300A, FDPOL05.D121300A, FDP7B05. D121300B, FDPOL08.D121500A, and FDP7B08.D121500A.

wellhead price of $3.94 per thousand cubic feet (1999 dollars), as a result of the projected increases in demand for natural gas by electricity generators.

In the short term (through 2003), the projected increases in natural gas prices in the analysis cases that include CO_2 caps (relative to the reference case projections) result from projected rapid increases in demand for gas in the electricity generation sector, as power plant operators are expected to dispatch gas-fired generators in lieu of coal-fired generators. In the long term, the cumulative market effects of the projected annual increases in demand over the forecast period keep projected prices higher in the cases that include CO_2 emission caps. Thus, although the total projected demand for natural gas in 2020 is only 8 percent higher in the integrated 2005 case than in the reference case, the cumulative increase of 37 trillion cubic feet results in a projected wellhead gas price that is $0.91 per thousand cubic feet, or 29 percent, higher than projected in the reference case.

The projected high prices are expected to have three major effects on the market:

- First, higher wellhead prices are expected to be passed along to consumers as higher end-use prices, reducing the demand for natural gas in other sectors and moderating the expected increase in total demand. For example, in 2005, residential consumers are projected to pay as much as 12 percent more for natural gas in the cases with CO_2 caps than in the reference case. In the integrated 2005 case, electricity generators are projected to pay about $3.91 per million Btu for natural gas, compared with $2.89 in the reference case. Stronger demand and higher wellhead prices are projected to account for the price increase. In addition, electricity generators are projected to pay a CO_2 allowance fee of $1.65 per million Btu. In 2020, the projected price of natural gas for electricity generators in the integrated 2005 case is $4.58 per million Btu plus an allowance fee of $1.63, as compared with $3.68 and no allowance fee in the reference case.

- Second, higher price projections also are expected to result in higher projected revenues for the natural gas industry. Total revenues for gas producers can be estimated by multiplying the average projected wellhead price by projected production. By this measure, estimated industry revenues from gas production are expected to be $52 billion in 2005 in the reference case and $82 billion in the integrated 2005 case. While expanding production increases costs, the increase in revenues should also lead to increased profits for the industry.

- Third, the impact of increased natural gas use in the electricity generation sector would also be felt by consumers in other sectors, because gas prices would increase. Homeowners and the owners of commercial buildings and industrial establishments are projected to see increases in their gas bills in the CO_2 cap and integrated cases. For example, in the integrated 1990-7% 2005 case, total expenditures for natural gas in the non-electricity sectors nationwide are projected to be nearly $25 billion higher in 2010 than projected in the reference case (Table 16). By sector, increases in total expenditures for natural gas relative to the reference case are projected to be $6 billion for the residential sector, $4 billion for the commercial sector, and $15 billion for the industrial sector.

Renewable Fuels Markets

Introduction

Renewable energy technologies, which are virtually emission free, can be attractive alternatives to fossil fuels, especially if emissions need to be reduced. This section discusses the projected impacts of the emission cap cases described in Chapter 2 on renewable capacity additions and generation. The central station renewables analyzed here include biomass, conventional hydroelectricity, geothermal, municipal solid waste, solar energy, and wind.

Biomass fuels include agricultural residues, forestry residues, energy crops, and urban wood waste and mill residues. About 8,000 megawatts of dedicated biomass-fired generating capacity is in use today.[16] Of the total, 6,000 megawatts is used by industrial facilities to produce cogenerated electricity and heat for their own use, primarily in the pulp and paper industry. A new advanced technology, integrated gasification combined-cycle technology, is now entering the market and is assumed to be commercially available beginning in 2005. In addition, energy crops grown specifically to serve as energy fuels are now being tested, and they are assumed to become commercially available in 2010. Among renewables, biomass-fired plants are especially attractive because they can be run nearly continuously, unlike wind and solar facilities that are dependent on intermittent fuel sources. In addition, because biomass growth sequesters CO_2, the use of biomass for electricity generation is considered a net zero CO_2-emitting technology.

In addition to its use in dedicated facilities, it is also assumed that biomass can be used in place of or along with coal in coal-fired plants where it is economically attractive. A small number of coal-fired plants are now using some biomass as part of the fuel mix, and studies have suggested that coal plants could burn between 3 and 5 percent biomass fuel without expensive plant changes. As a result, where biomass fuels are available, it is assumed that up to 5 percent of the fuel used in a coal plant can be biomass based. This level of biomass

Table 16. Projected Total Expenditures for Natural Gas in the Residential, Commercial, and Industrial Sectors, 2005-2020
(Billion 1999 Dollars)

Sector	2005	2008	2010	2015	2020
Reference Case					
Residential	36.21	36.94	37.12	38.56	41.36
Commercial	19.72	20.77	21.35	22.29	23.58
Industrial	33.04	35.50	36.66	40.60	46.50
Total	**88.97**	**93.20**	**95.13**	**101.45**	**111.44**
Integrated 1990-7% 2005 Case					
Residential	39.33	42.31	42.96	43.96	46.16
Commercial	21.76	24.08	24.94	25.92	27.10
Industrial	41.91	49.56	51.84	55.46	59.44
Total	103.01	115.95	119.74	125.34	132.71
Difference Between Cases					
Residential	3.12	5.37	5.83	5.41	4.80
Commercial	2.04	3.31	3.60	3.63	3.52
Industrial	8.87	14.06	15.18	14.86	12.94
Total	14.04	22.74	24.61	23.89	21.27
Percentage Difference Between Cases					
Residential	8.6	14.5	15.7	14.0	11.6
Commercial	10.4	15.9	16.9	16.3	14.9
Industrial	26.8	39.6	41.4	36.6	27.8
Total	15.8	24.4	25.9	23.6	19.1

Source: National Energy Modeling System, runs MCBASE.D121300A and FDP7B05.D121300B.

[16] Dedicated biomass plants are facilities designed specifically to burn biomass as their primary fuel.

co-firing in coal plants is an economically attractive CO_2 emission reduction strategy, because it can be done at relatively low cost and it displaces a high-carbon fuel. However, because CO_2 reduction scenarios typically reduce expected coal use, opportunities for biomass co-firing with coal are projected to be diminished in such cases.

Geothermal power uses heat from the earth for electric power generation. Accessible geothermal resources can be found in the West and Northwest, although some are near National parks and other environmentally sensitive areas. Nearly 3,000 megawatts of geothermal power capacity is in service today. Like biomass facilities, geothermal plants can be run almost continuously, and they are available whenever power is needed. Some geothermal plants emit small amounts of CO_2.

Municipal solid waste (MSW) includes organic and other combustible urban waste. About 3,000 megawatts of MSW capacity is currently in operation in the United States, most for direct electricity generation and some for cogeneration. MSW conversion to electricity can occur through either solid waste combustion or combustion of landfill gas. Although most of the MSW facilities that exist today use solid waste, this analysis projects that all new MSW capacity will use landfill gas.

Solar power includes solar photovoltaic (PV) and solar thermal facilities. PV, which uses solar cells to convert sunlight directly to electricity, provides grid-serving power in central station plants, distributed units, and modules installed on residences and commercial buildings. PV offers zero emissions, can be installed close to customer loads, and is generally available during high demand periods associated with hot, sunny conditions. PV units are relatively expensive, however, and they are unavailable when the sun is down or blocked. PV is most competitive where solar conditions are best or where peak electricity costs are very high.

Solar thermal concentrates sunlight to produce steam for peaking electricity generation. Currently more than 330 megawatts of solar thermal capacity is in operation in Southern California. When combined with energy storage (such as molten salt), solar thermal can provide reliable power when it is needed. Solar thermal offers zero emissions and, like PV, is generally available during high demand periods associated with hot weather. However, the technology is still in the early stages of development, with relatively high costs and uncertain performance, and inadequate solar conditions east of the Mississippi River limit its potential market.

More than 78,000 megawatts of conventional hydroelectric capacity provides more than 75 percent of all U.S. renewable electricity generation today. Hydroelectric power is a proven, reliable technology with low operating costs. Although there are potential opportunities for additional dams and for capacity additions or efficiency improvements at existing facilities, building new hydroelectric is costly, and environmental objections are significant. The reference case for this analysis projects a slight decline in electricity generation from existing hydroelectric capacity through 2020. Public willingness to accept the construction of new hydroelectric dams currently appears to be low in light of environmental tradeoffs.

Among the renewable generation technologies, central station wind power has shown the most significant growth in recent years, and it is expected to continue to grow in the near future. Spurred by declining capital costs, improving performance, and both Federal and State incentives, total U.S. wind generating capacity is estimated to have increased by nearly 70 percent from 1997 through 2000, to more than 2,700 megawatts. Further near-term additions are also projected.

Like other renewables, wind power produces no emissions, but there are factors that may limit its development. For example, wind resources are often far from electricity customers, and if the wind is not blowing the resources may not be available during peak daily or seasonal loads. Wind power also still costs more than fossil-fueled alternatives. The technology is fairly new and untested on a large scale, and it faces environmental objections, primarily for visual intrusion. In addition, unpredictable variations in output from intermittent generators like wind and solar affect other generators and the overall stability of large interconnected electricity networks, leading to higher costs. The point at which such problems might occur is unknown. For this analysis it is assumed that PV and wind power together can provide no more than 12 percent of any region's annual electricity generation.

Despite some uncertainty about State programs, where sufficient information is available, EIA projections include estimates of new generating capacity using renewable energy resources resulting from current State renewable portfolio standards (RPS), other mandates, green power, and other voluntary programs encouraging renewable energy technologies. State RPS and other mandates are projected to add 5,065 megawatts of new renewable energy capacity by 2020, including 4,377 megawatts from RPS alone. Total RPS and mandated additions include 2,900 megawatts of new wind capacity, 1,145 megawatts of new landfill gas capacity, 840 megawatts of biomass, 117 megawatts of geothermal, and 64 megawatts of new solar (photovoltaic and thermal). Voluntary programs contribute an additional 291 megawatts, 230 megawatts of which is from wind plants, 41 megawatts from landfill gas, 16 megawatts from biomass, and 4 megawatts from solar photovoltaics. The estimates are included in projections for all the cases in this analysis.

Projections of large increases in renewable energy use should be viewed with caution. The availability of renewable energy resources to support major growth is often uncertain, particularly in the case of biomass, geothermal, and wind resources, and the costs and performance of new technologies also are uncertain. Consumer tastes, environmental accommodation, and market acceptance may be problematic, and the ability of different suppliers and regions to integrate large proportions of renewables, especially intermittent sources like solar and wind, into overall supply is not known.

Reference Case Projections

Because they cost more than fossil alternatives, renewable energy technologies are projected to account for very little new generating capacity through 2020 in the reference case, other than near-term builds in response to State RPS or other requirements. In 2000, nonhydroelectric renewables, including both direct generation and industrial cogeneration, are estimated to provide 79 billion kilowatthours (2.1 percent) of all U.S. grid-connected electricity generation and 2.4 percent of retail sales.[17] When the 290 billion kilowatthours of expected conventional hydroelectric generation is included, the total renewable share of U.S. electricity supply in 2000 generation is estimated to be 9.8 percent of generation and 11.0 percent of retail sales. In the reference case, generation from nonhydroelectric renewables is projected to increase to 141 billion kilowatthours in 2020, and its share of total U.S. electricity supply is projected to be 2.7 percent of generation (Figure 21) and 2.9 percent of sales. Generation from conventional hydroelectric capacity is expected to remain essentially unchanged.

Emission Reduction Cases

As the cost of generating power from fossil fuels increases in the emission reduction cases, renewable generation technologies are expected to become more attractive. The projected changes are small in the NO_x and SO_2 cap cases, where the costs of complying with the emission caps are expected to fall mainly on existing fossil plants. New fossil plants, against which new renewable plants would compete when capacity is needed, are assumed to be built to meet current emission standards. Because NO_x and SO_2 emissions from new fossil technologies, especially natural gas facilities, are low, the projected costs of NO_x and SO_2 allowances have little impact on their economics. As a result, as in the reference case, fossil generating technologies (particularly natural gas) continue to be more economical than new renewable capacity in the NO_x and SO_2 cap cases.

The relative economics of new fossil versus new renewable generation technologies change in the CO_2 cap and integrated cases. Carbon allowance fees are expected to raise the costs of all fossil technologies, both existing and new. Natural gas generating technologies are expected to play the key role in reducing CO_2 emissions, but new renewable technologies also are projected to contribute.

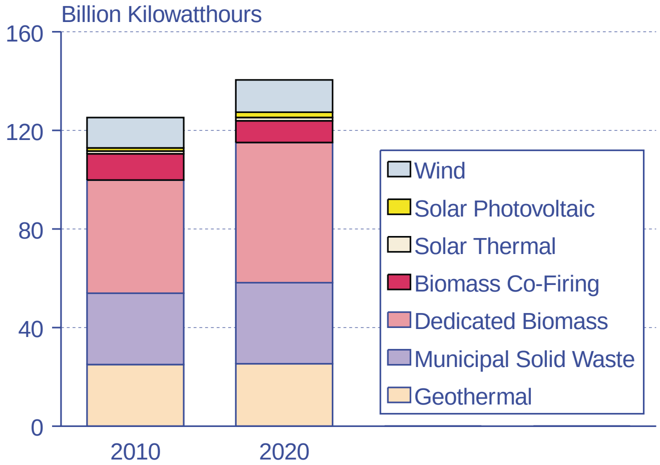
Renewables are expected to make their most significant contributions in the most stringent cases, which assume reductions in power sector CO_2 emissions to their 1990 level by 2005 and further to 7 percent below the 1990 level on average over the 2008 to 2012 time period. The CO_2 1990-7% 2005 case projects the greatest increase in renewable energy capacity. In this case, the share of total power generation from nonhydroelectric renewables is projected to increase to 8.0 percent of total generation and 9.2 percent of sales in 2020, much higher than projected in the reference case (404 billion kilowatthours in 2020, as compared with 141 billion kilowatthours in the reference case). Conventional hydroelectric generation is also projected to increase slightly, by 6 billion kilowatthours over the reference case projection for 2020. Nonhydroelectric renewable generating capacity is also projected to make up a larger share of total capacity in 2020 in the CO_2 1990-7% 2005 case than in the reference case (6.3 percent and 2.3 percent, respectively).

The largest increases in renewable electricity generation in the CO_2 1990-7% 2005 case relative to the reference case are projected for biomass, geothermal, and wind (Figure 22). Biomass generation (excluding cogeneration) in 2020 is projected to increase from 22 billion kilowatthours in the reference case to 119 billion kilowatthours in the CO_2 1990-7% 2005 case, with 65 percent of the increase coming from biomass use in dedicated plants and the rest from increased biomass co-firing in coal plants. Geothermal generation in 2020 is projected to increase from 25 billion kilowatthours in the reference case to 113 billion kilowatthours in the CO_2 1990-7% 2005 case. Wind generation in 2020 is projected to increase from 13 billion kilowatthours in the reference case to 86 billion kilowatthours in the CO_2 1990-7% 2005 case, reaching the assumed limit of 12 percent (due to system stability requirements) of total generation in two regions by 2020. Smaller relative increases between the reference case and the CO_2 1990-7% 2005 case in 2020 are projected for landfill gas generation (7 billion kilowatthours) and conventional hydropower (6 billion kilowatthours). Because large-scale central station solar generating technologies are expected to remain more costly than other alternatives in all the analysis cases, they are not projected to provide additional generation relative to the reference case levels.

Although biomass, geothermal, and wind all are projected to provide more electricity generation in the cases with CO_2 caps than in the reference case, their contributions are expected to occur during different parts of

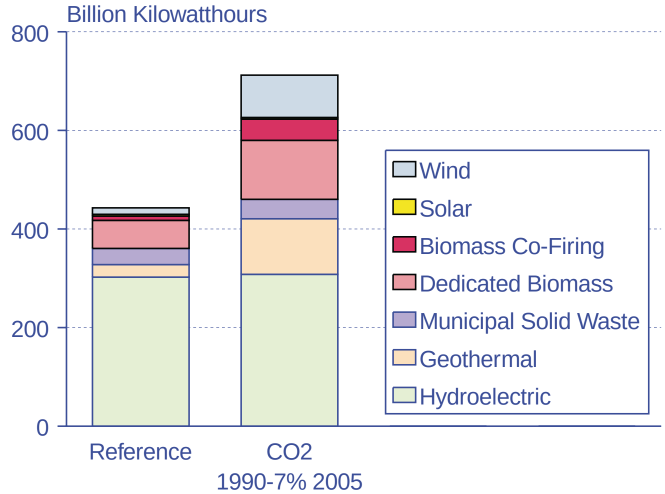
[17]State renewable portfolio standards are variously defined relative to electricity generation or to sales.

Figure 21. Projected Nonhydroelectric Renewable Generation by Fuel in the Reference Case, 2010 and 2020



Source: National Energy Modeling System, run MCBASE. D121300A.

Figure 22. Projected Renewable Electricity Generation by Fuel in the Reference and CO_2 1990-7% 2005 Cases, 2020



Source: National Energy Modeling System, runs MCBASE. D121300A and FDC7B05.D121300A.

the 2000-2020 time period. The vast majority of new dedicated biomass and wind-powered plants are projected to enter service well after 2010, in response to both higher natural gas prices and decreased costs for renewable energy technologies. In contrast, geothermal power and biomass co-firing in coal plants are projected to be economical when the emission caps are first introduced, increasing rapidly in the early years of the forecast. In the later years of the forecast, as less coal-fired capacity remains available, the potential for co-firing declines, and the most cost-effective geothermal opportunities are already taken.

In the CO_2 1990-7% 2005 case, electricity generation from biomass co-firing is projected to increase from 3 billion kilowatthours in 2000 to 38 billion kilowatthours in 2005, peaking at 54 billion kilowatthours in 2010. By comparison biomass co-firing is projected to provide only 11 billion kilowatthours of electricity generation in 2010 in the reference case. After 2010, declining coal-fired capacity is projected to result in reduced biomass co-firing, and its contribution in the CO_2 1990-7% 2005 case slips to 43 billion kilowatthours in 2020. Landfill gas capacity and generation are projected to have accessed almost all available cost-effective sites by 2010, with the result that few additional cost-effective landfill opportunities are expected to be available later in the forecast period.

Most of the increase in renewable fuel use projected in the in the CO_2 1990-7% 2005 case is expected to occur in the western States. The total projected increase in renewable capacity in the CO_2 1990-7% 2005 case relative to the reference case projection for 2020 is 46 gigawatts, of which only 3 gigawatts (6.8 percent) is expected to be located in the five regions along the Atlantic seaboard.

Sensitivity Cases

Because less expensive alternatives can meet most or all of the remaining requirements, reduced mitigation requirements in the sensitivity cases disproportionately reduce—and in one case eliminate altogether—the expansions of renewable energy capacity and generation projected in the integrated cases. In the SO_2 sensitivity case, no additional renewable generating capacity is projected beyond the reference case level. In the integrated sensitivity case, renewable capacity in 2020 is projected to be 16 gigawatts greater than projected in the reference case and 30 gigawatts lower than projected in the CO_2 1990-7% 2005 case.

In the CO_2 1990-7% 2005 case, which assumes the most stringent emission reduction targets in this analysis, renewables enter the projections particularly heavily after 2015, after other less costly alternatives are projected to be exhausted. When less stringent emission caps are assumed, these late-period demands are eliminated, and with them most of the projected additions of new renewable generating capacity in the forecasts. In the electricity generating sector (excluding cogeneration), wind capacity, which is projected to reach 30 gigawatts in the CO_2 1990-7% 2005 case, is projected to reach only 13 gigawatts by 2020 in the integrated sensitivity case—8 gigawatts more than projected in the reference case. Similarly, biomass capacity, which is projected to reach 12 gigawatts by 2020 in the CO_2 1990-7% 2005 case, is projected to reach only 4 gigawatts in the integrated sensitivity case—2 gigawatts more than projected in the reference case.

In contrast to other renewable energy options, biomass co-firing is projected to increase in the integrated sensitivity case compared with the other cases, as most coal-fired capacity is projected to remain in operation through 2020. Whereas in the reference case biomass co-firing with coal produces a maximum of 12 billion kilowatthours of electricity generation in 2011 and provides 9 billion kilowatthours in 2020, in the CO_2 1990-7% 2005 case it is projected to increase to 54 billion kilowatthours in 2010 before declining to 43 billion kilowatthours in 2020. In the integrated sensitivity case, generation from biomass co-fired with coal reaches a projected maximum of 71 billion kilowatthours in 2010 before declining to 56 billion by 2020.

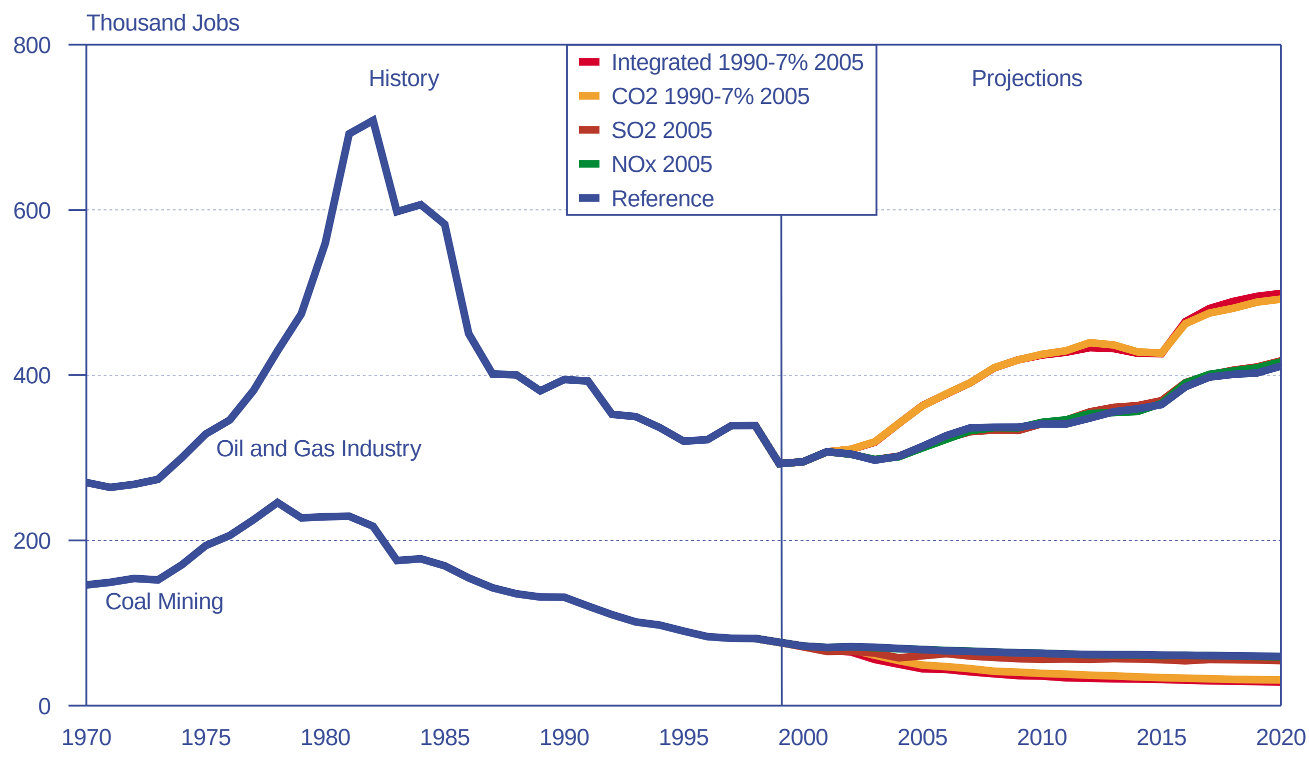
Industry Employment Impacts

The analysis cases in this report can be expected to produce both broad macroeconomic and specific fuel sector impacts on employment. Macroeconomic impacts result from increased energy prices that will in turn affect industrial sectoral output, gross domestic product, overall productivity in the economy, and employment. In the primary fuel sectors, emission limits and higher prices are expected to alter the levels of overall and regional production of the fuels used for electricity generation and to change the levels of both direct employment and employment in associated industries and the surrounding infrastructure. In particular, the coal industry is expected to experience employment declines because of reduced coal production, and the natural gas and renewables industries are projected to show employment gains as electricity generators switch fuels. Relative to the reference case, projected employment gains in the oil and gas sectors in 2020 generally match projected employment losses in the coal sector in the NO_x and SO_2 cap cases but substantially exceed them in the CO_2 cap cases.

Coal Industry Employment

Between 1978 and 1999, the number of miners employed in the U.S. coal industry fell by 5.4 percent per year, declining from 246,000 to an estimated 77,000. The decrease primarily reflected strong growth in labor productivity, which increased at an annual rate of 6.4 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, which require much less labor per ton of output than mines located in the Interior and Appalachian regions. With improvements in productivity continuing over the forecast period, further declines in employment of 1.8 and 0.5 percent per year are projected from 1999 through 2010 and from 2010 through 2020, respectively (Figure 23). In absolute terms, coal mine employment is projected to decline in the reference case from 77,000 in 1999 to 63,000 in 2010 and 60,000 in 2020.

Figure 23. Coal Mining and Oil and Gas Industry Employment, 1970-2020



Sources: **History:** Coal—Energy Information Administration (EIA), *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 1992); and EIA, *Coal Industry Annual 1998*, DOE/EIA-0584(98) (Washington, DC, June 2000), and previous issues. Oil and Gas—Bureau of Labor Statistics. **Projections:** National Energy Modeling System, runs MCBASE.D121300A, MCNOX05. D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

In the NO_x and SO_2 cases, overall U.S. coal consumption and production are not significantly different from the reference case. In the NO_x cases the minor changes in coal production, relative to the reference case, lead to only slight changes in coal employment levels, as reductions in NO_x emissions do not significantly affect regional coal production patterns (Table 17). In the SO_2 cases, however, differences in sulfur content by supply region lead to some shifts in the regional distribution of coal production, with output in the relatively high-sulfur, labor-intensive coal fields in the Appalachian and Interior coal supply regions projected to be lower than in the reference case forecast and output from the low-sulfur, less labor-intensive coal mines in the Powder River Basin projected to be higher. In the SO_2 2005 case, U.S. coal mine employment is projected to decline by 1.6 percent per year, from 77,000 miners in 1999 to 55,000 in 2020, compared with a projected decline of 1.2 percent per year in the reference case.

In the CO_2 and integrated cases, lower levels of coal production in all supply regions relative to the reference case result in lower coal industry employment in all regions. In the integrated 1990-7% 2005 case, coal mine employment is projected to decline by 4.7 percent a year, to 28,000 by 2020.

It should also be noted that coal mines typically are located away from cities and are a significant source of income and employment in rural areas. In addition, with substantial contraction of the U.S. coal industry projected in the CO_2 cap cases, employment in the U.S. rail industry, which derives considerable revenues from coal shipments, also would be greatly affected (see box on page 38).

Oil and Gas Employment

Employment in the oil and gas industries is expected to grow in future decades, accompanying the projected increases in drilling and production for natural gas. Employment has fallen since reaching its peak of more than 700,000 employees in 1982. In 1999, average annual employment was 293,000 employees nationally, its lowest level since 1974. In 2000, employment at the end of the third quarter is estimated to have been 20,000 workers higher than it was at the end of the third quarter of 1999, responding to higher prices and increased drilling for oil and natural gas.

In the reference case, total annual average employment in the oil and gas production industry is projected to increase by 1.4 percent and 1.9 percent per year from 1999 to 2010 and from 2010 through 2020, respectively, reaching 411,000 jobs by 2020.[18] The increase is expected to be concentrated in the oil and gas services industry (which includes oil and gas exploration), rather than production. Most of the expected increase is due to the increased level of drilling required to meet the projected strong demand for gas, and to a projected increase in the number of offshore wells.

Projected increases in natural gas use as a result of CO_2 emission caps would require increases in natural gas production, with a significant impact on employment levels in the gas industry. In the integrated 1990-7% 2005 case, average annual employment in 2005 in the oil and gas industry is estimated to be 363,000, roughly 70,000 jobs higher than it was in 1999 and 49,000 higher than projected in the reference case. The difference between the integrated 1990-7% 2005 case and the reference case

Table 17. Projected Impacts on Energy Industry Employment, 2005-2020
(Thousand Jobs)

Industry	Analysis Case	1999[a]	2005	2010	2020	Average Annual Percent Change
Coal	Reference	77	68	63	60	-1.2
	NO_x 2005	77	68	63	59	-1.2
	SO_2 2005	77	60	56	55	-1.6
	CO_2 1990-7% 2005	77	49	39	31	-4.2
	Integrated 1990-7% 2005	77	45	36	28	-4.7
Oil and Gas Extraction	Reference	293	314	341	411	1.6
	NO_x 2005	293	312	343	416	1.7
	SO_2 2005	293	313	341	417	1.7
	CO_2 1990-7% 2005	293	363	425	492	2.5
	Integrated 1990-7% 2005	293	363	424	499	2.6

[a]Preliminary estimates.
Source: National Energy Modeling System, runs MCBASE.D121300A, MCNOX05.D121300A, MCSO205.D121300A, FDC7B05.D121300A, and FDP7B05.D121300B.

[18]This analysis uses the econometric forecasting model described in J. Kendell, "Employment Trends in Oil and Gas Extraction," in Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1999*, DOE/EIA-0607(99) (Washington, DC, August 1999).

grows between 2005 and 2010. By 2010, employment in the integrated case is 424,000—more than 83,000 higher than projected in the reference case. Although this projection is more than 130,000 higher than the 1999 employment level, it still is lower than the levels of employment in the oil and gas industry in the late 1970s and early 1980s. By 2020, total employment in the oil and gas industry is projected to reach 499,000 jobs in the integrated 1990-7% 2005 case.

In 2005, projected natural gas production in the integrated 1990-7% 2005 case is roughly 13 percent higher than projected in the reference case, and total employment in the oil and gas industry is nearly 16 percent higher. The difference in employment projections between the scenarios results from an 8-percent increase in the expected number of production workers and a 20-percent increase in the number of service workers relative to the reference case. Thus, the projected increase in employment results primarily from the effort required to bring the new natural gas production on line, including infrastructure development and identification of new resources. Although technology advances tend to reduce the number of workers required to bring new resources into play, the increasing scarcity of new resources makes it harder to bring them on line. Therefore, in the CO_2 cap cases, the increasing difficulty of finding new resources and bringing them to market is expected to cause total oil and gas employment to grow more quickly than total natural gas production.

Renewables Employment

Multi-emission strategies are likely to result in increased U.S. employment in renewable energy industries, in equipment manufacturing, in new facility construction, and in ongoing operation and maintenance of generating facilities using renewable energy. These increases are expected to be small, however, because most renewables—geothermal, solar, and wind, for example—involve little ongoing extraction, preparation, or transportation. Only biomass involves notable labor in energy production, such as for energy crops or for waste preparation. Biomass transportation, while significant, remains local.

Much of the projected new employment in renewable energy industries is expected to be in the manufacturing and construction of new energy generating facilities. To the extent that the United States gains comparative advantage in exporting renewable energy technologies, and to the (relatively small) extent that domestic manufacturing and construction replace imported fuels, U.S. employment is also expected to increase. In addition, some increase in employment is expected for the ongoing operation and maintenance of new renewable energy generating facilities; however, the increase is expected to be small relative to the projected employment increase in the oil and gas industry.

Macroeconomic Impacts

The imposition of new, more stringent emission caps is expected to affect the U.S. economy fundamentally through an increase in delivered energy prices. Higher energy costs would reduce the use of energy by shifting production toward less energy-intensive sectors, by replacing energy with labor and capital in specific production processes, and by encouraging energy conservation. Although reflecting a more efficient use of higher cost energy, the change would also tend to lower the productivity of other factors in the production process because of a shift in the relative prices of capital and labor relative to energy. Moreover, a rise in energy prices would raise non-energy intermediate and final product prices and introduce cyclical behavior in the economy, resulting in output and employment losses in the short run. In the long run, however, the economy can be expected to recover and move back to a more stable growth path. Table 18 summarizes the projected macroeconomic impacts in the reference and two integrated cases.

In the most stringent case—the integrated 1990-7% 2005 case—inflation in the economy is projected to rise rapidly above the rate projected in the reference case. Higher projected electricity and natural gas prices initially affect only the energy portion of the consumer price index (CPI). The higher projected energy prices are expected to be accompanied by general price effects as they are incorporated in the prices of other goods and services. In this case, the level of the CPI is projected to be about 1.0 percent above the reference case by 2005 and in 2010 is projected to be 1.2 percent above the reference case projection. After 2010, however, price inflation is projected to abate, and the CPI is expected to begin returning to reference case levels. By 2020, the projected level of the CPI is 0.2 percent above the reference case projection.

How would the projected changes in energy prices affect the general economy? In both of the integrated cases, energy prices are projected to continue increasing relative to the reference case projections through the target year of the emission reduction. The most rapid increases in energy prices are projected during the first 4 years of the forecast period, because the power sector is expected to turn quickly from coal to natural gas to comply with the CO_2 emission caps. Energy prices are projected to continue rising after 2004, but the rate of increase is expected to be more gradual. Capital, labor, and production processes in the economy would need to be adjusted to accommodate the new, higher set of energy and non-energy prices.

Higher energy prices would affect both consumers and businesses. Households would face higher prices for energy and the need to adjust spending patterns. Rising

Table 18. Projected Macroeconomic Impacts in the Reference Case and Two Integrated Emission Reduction Cases, 2005-2020

Projection	2005	2010	2015	2020
Real Gross Domestic Product (Billion 1992 Dollars)				
Reference	9,869	11,461	13,107	14,842
Integrated 1990-7% 2005	9,754	11,401	13,104	14,813
Integrated 1990-7% 2008	9,809	11,377	13,084	14,821
Real Gross Domestic Product (Percent Change from Reference Case)				
Integrated 1990-7% 2005	-1.2	-0.5	0.0	-0.2
Integrated 1990-7% 2008	-0.6	-0.7	-0.2	-0.1
Consumer Price Index (Index, 1982-1984 = 100))				
Reference	193.2	219.7	250.9	295.8
Integrated 1990-7% 2005	195.0	222.3	252.8	296.5
Integrated 1990-7% 2008	194.1	222.0	253.0	297.0
Consumer Price Index (Percent Change from Reference Case)				
Integrated 1990-7% 2005	1.0	1.2	0.8	0.2
Integrated 1990-7% 2008	0.5	1.0	0.8	0.4
Unemployment Rate (Percent)				
Reference	4.2	4.7	4.5	4.1
Integrated 1990-7% 2005	4.8	4.8	4.4	4.1
Integrated 1990-7% 2008	4.5	5.0	4.5	4.1
Unemployment Rate (Change in Rate from Reference Case)				
Integrated 1990-7% 2005	0.6	0.2	-0.1	0.0
Integrated 1990-7% 2008	0.3	0.3	0.0	0.0
Disposable Income (Billion 1992 Dollars)				
Reference	7,053	8,242	9,494	10,858
Integrated 1990-7% 2005	6,956	8,160	9,458	10,808
Integrated 1990-7% 2008	7,000	8,150	9,445	10,813
Disposable Income (Percent Change from Reference Case)				
Integrated 1990-7% 2005	-1.4	-1.0	-0.4	-0.5
Integrated 1990-7% 2008	-0.8	-1.1	-0.5	-0.4
Non-agricultural Employment (Million Employed)				
Reference	140.3	148.6	154.8	161.3
Integrated 1990-7% 2005	138.9	147.9	154.9	161.1
Integrated 1990-7% 2008	139.5	147.6	154.6	161.2
Non-agricultural Employment (Change from Reference Case, Million Employed)				
Integrated 1990-7% 2005	-1.5	-0.7	0.1	-0.2
Integrated 1990-7% 2008	-0.8	-1.0	-0.2	-0.1

Note: All percent changes and changes from the reference case are rounded to one decimal point.
Source: Simulations of the Standard & Poor's DRI Macroeconomic Model of the U.S. Economy.

expenditures for energy would take a larger share of the family budget for goods and service consumption, leaving less for savings. Energy services also represent a key input in the production of goods and services. As energy prices increase, the costs of production rise, placing upward pressure on the prices of all intermediate goods and final goods and services in the economy. These transition effects tend to dominate in the short run, but dissipate over time.

Expectations on the part of power suppliers and consumers of energy play a key role. On the part of the power suppliers, current investment decisions depend on expectations about future markets. They will make decisions by reviewing each technology's current and future capital, operations and maintenance, and fuel costs. Both current and expected future costs are considered because generating assets require considerable

Macroeconomic Effects of Alternative Implementation Instruments

All the cases considered above assume a marketable emission permit system, with a no-cost allocation of the permits based on historical emissions. In meeting the targets, power suppliers are free to buy and sell allowances at a market-determined price for the permits, which represents the marginal cost of abatement of any given pollutant. An alternative form of permit system would auction the permits to power suppliers. The price paid for the auctioned permits would equal the price paid for traded permits under the no-cost allocation system used for this study. However, the two systems imply a different distribution of income.

In the no-cost allocation system, there would be a redistribution of income flows between power suppliers in the form of purchases of emission permits. There would be no net burden on the power suppliers as a whole, only a transfer of funds between firms. While all firms are expected to benefit from trading, the burden would vary among firms. With a Federal auction system, in contrast, there would be a net transfer of income from power suppliers to the Federal Government. In the integrated 1990-7% 2005 case, the magnitude of the transfer would be approximately $30 billion (1992 dollars) in 2010 and almost $40 billion in 2020. The key question at this juncture turns on the use of the funds by the Federal Government. If the funds were returned to the power suppliers, the effect would be the same as in the no-cost allocation scheme, but with the Federal Government establishing the permit market mechanism. Another use of the funds might be to return them to consumers either in the form of a lump-sum transfer or in the form of a personal income tax cut, compensating consumers for the higher prices paid for energy and non-energy goods and services.[a]

Relative to the no-cost allocation of permits, an auction that transfers funds to consumers in a lump sum would help to maintain their level of overall consumption. With the transfer, however, total investment would decline relative to the allocation system. The two effects would tend to counterbalance each other, but not completely. Returning collected auction funds to the consumer would tend to have a slightly more positive effect than the negative effect on investment for the first few years, but after 2005 investment would tend to rebound faster and contribute increasingly to the recovery. As a result, real GDP would be expected to recover to reference case levels faster under the no-cost allocation system. Over the entire period, however, the net impacts on real GDP are expected to be similar in both magnitude and pattern under the two potential allocation schemes.

Another approach is to recycle the auctioned revenues back to either consumers or business through a reduction in marginal tax rates on capital or labor. Unlike the no-cost allocation or the lump-sum payment to consumers, this approach may lower the aggregate cost to the economy by shifting the tax burden away from distortionary taxes on labor and capital toward the taxation of an environmental pollutant. Most often this research is based on a general equilibrium approach, where all factors are assumed to be utilized fully, as in the work by Goulder, Parry, and Burtraw.[b] Revenue recycling benefits may also apply in a setting where transition effects on the economy, such as considered in the current EIA study, are the focus.[c]

[a]For a discussion of the relative merits of alternative policy instruments, see Perman, Ma, and McGilvray, "Pollution Control Policy," in *Natural Resource and Environmental Economics* (Addison Wesley Longman, 1996).

[b]L.H. Goulder, I.W.H. Parry, and D. Burtraw, "Revenue-Raising Versus Other Approaches to Environmental Protection: The Critical Significance of Pre-existing Tax Distortions," *RAND Journal of Economics*, Vol. 28. No. 4 (Winter 1997), pp. 708-731.

[c]See also Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998), Chapter 6 "Assessment of Economic Impacts."

investment and last many years. These forward-looking decisions help to moderate the ultimate price effects passed on to the rest of the economy. The views of consumers and businesses are also influenced by expectations of future price changes. Inflationary expectations on the part of consumers and businesses are characterized as a function of recent rates of increase in prices and spending.[19] Thus, although expectations are important, they are based in general on recent changes, not on forward-looking expectations in the absence of change. A more forward-looking view would suggest that the announcement of a policy would shape expectations and decisions that could lead to reduced impacts on the aggregate economy.

In the integrated 1990-7% 2005 case, the unemployment rate is projected to rise by 0.6 percentage points, reaching 4.8 percent in 2005. Along with the rise in inflation and unemployment, real output of the economy is projected to decline. Real gross domestic product (GDP) is projected to fall by 1.2 percent relative to the reference case in 2005, and employment in non-agricultural

[19]R.E. Brinner and M.J. Lasky, "Model Overview: Theory and Properties of the DRI Model of the U.S. Economy," in *U.S. Quarterly Model Documentation*, Version US97A.

establishments is projected to decline by 1.5 million jobs. Similarly, real disposable income is expected to fall by 1.4 percent. As the economy adjusts to higher energy prices, inflation begins to subside in the forecasts after 2005. At the same time, the economy begins to return to its long-run growth path. By 2010, the projected unemployment rate is only 0.2 percentage points above the reference case, and real GDP is projected to be only 0.5 percent below the reference case projection. The impact on non-agricultural employment is projected to diminish to about 200,000 jobs relative to reference case in 2020. The adjustment process is expected to be nearly complete in 2020, approaching the reference case path, with the unemployment rate at the reference case level and real GDP only 0.2 percent below the reference case level.

In the integrated 1990-7% 2008 case, the energy price impacts are projected to be both smoother and smaller in magnitude. The effect on inflation is projected to be smaller, and the CPI is projected to peak at about 1.0 percent above the reference case level in 2010. As a result the impact on the measures of economic performance is moderated throughout the forecast period relative to that in the integrated 1990-7% 2005 case. The unemployment rate is projected to be 0.3 percentage points above the reference case in the 2005 through 2010 period. The impact on real GDP is projected to reach 0.7 percent below the reference case in 2010, and real disposable income is projected to reach its lowest point at 1.1 percent below the reference case in 2010. As with the integrated 1990-7% 2005 case, the integrated 1990-7% 2008 case projects a strong recovery after 2010, and most of the cyclical impacts are expected to dissipate by 2020, with the unemployment rate returning to the reference case level and real GDP only 0.1 percent below the reference case.

Three key observations follow from these cases:

- The faster the rise in the underlying energy prices, the stronger the cycle introduced in the macroeconomy.
- Given that the emissions caps are assumed to reach a plateau, the economy tends to revert back toward the reference case values in the long run after adjusting to the caps.
- With smaller emission reductions, the projected impacts on the economy are significantly smaller.