5. Fossil Fuel Supply

The impacts on fossil fuel suppliers of policies to limit carbon emissions will depend on how much carbon is in each type of fuel: the more carbon in the fuel, the more severe the impact. If the Kyoto Protocol carbon emissions reduction targets were imposed, the U.S. coal and oil industries would see lower consumption and production than in the reference case, which does not incorporate the Protocol, whereas the natural gas industry would expand. Natural gas wins out over coal and oil in the carbon reduction cases used for this analysis, because its carbon content per British thermal unit (Btu) is only 55 percent of that for coal and 70 percent of that for oil. As a result of higher natural gas consumption and lower oil and coal consumption, carbon emissions from natural gas are projected to be higher in the carbon reduction cases, while emissions from oil and coal are lower.

Natural Gas Industry

Natural gas is a clean, economical, widely-available fuel used in more than 58 million homes and more than 60 percent of the manufacturing plants in the United States. Almost one-quarter of the energy consumed in the United States comes from natural gas. Most of the natural gas consumed in the United States is produced domestically from wells in the central part of the Nation. Gas is transported from the Central United States by pipelines throughout the country and becomes more expensive the farther it must be shipped. Yet natural gas is generally cheaper than oil products, though more expensive than coal on the basis of heating values.

In 1996 the combustion of natural gas produced 318 million metric tons of carbon emissions in the United States, about one-fifth of the U.S. total. The industrial sector was responsible for the biggest share of those emissions, about 45 percent, followed by residential, commercial, and electricity generation in order of magnitude. Twelve years from now, if no carbon reduction measures are put in place, emissions from natural gas combustion are expected to be about 100 million metric tons higher than they were in 1996. Even though the projected emissions are higher in 2010, the natural gas share of total emissions increases only slightly from 1996.

Natural gas consumption, production, imports, and prices are all expected to rise in the reference case. Natural gas consumption increases more rapidly than consumption of any other major fuel in the reference case from 1996 to 2010. Natural gas use increases in all sectors, but consumption by electricity generators more than doubles to take advantage of the high efficiencies of combined-cycle units and the low capital costs of combustion turbines. By 2010 the generating capability of combined-cycle plants increases more than sixfold, and the generating capability of combustion turbines more than doubles. More than four-fifths of the new consumption is supplied by increased domestic production. The remainder comes from increased imports, primarily from Canada.

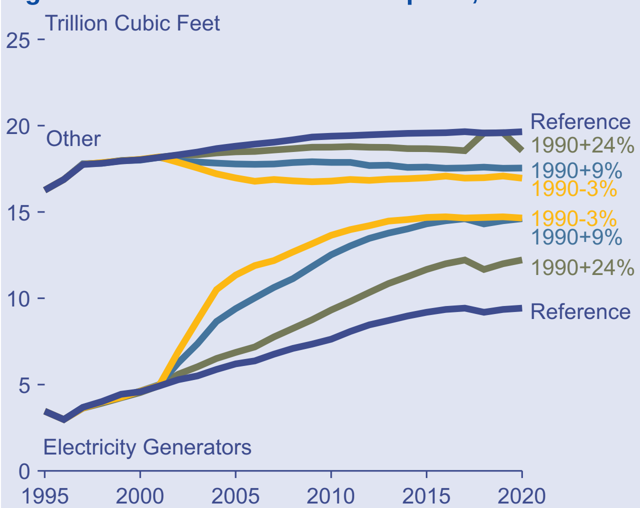
Two-thirds of the production increase between 1996 and 2010 is expected to come from onshore resources in the lower 48 States; the rest is expected to come from Alaska and lower 48 offshore resources. More production comes from onshore lower 48 resources, because roughly 75 percent of current proved reserves are located onshore, and continued technology improvements make development of the vast onshore unconventional resources more economical. Wellhead prices rise moderately in the reference case through 2010, reflecting increased consumption and its impact on resources, as each type of production progresses from larger, more profitable fields to smaller, less economical ones.

Policies designed to reduce carbon emissions would boost natural gas consumption, production, imports, and prices, principally because natural gas consumption would displace coal consumption in the electricity supply sector. In response, gas production and imports would increase, pushing up prices. In the 3-percent-below-1990 (1990-3%) case, for example, the natural gas share of the U.S. energy market is projected to increase from 24 percent in 1996 to 35 percent in 2010, compared with an increase of only 2 percentage points in the reference case. Following the imposition of a carbon price, higher prices for natural gas eventually would bring gas into competition with conservation (i.e., demand reduction) and renewable fuels, slowing the growth of gas consumption and prices.

Natural Gas Consumption

Natural gas plays a key role in the transition to lower carbon emissions, because it allows fuel users to consume the same number of Btu, while emitting less carbon. Thus, one strategy for fuel users seeking to quickly reduce coal use is to increase gas use. Natural gas consumption is expected to rise more rapidly in all the carbon reduction cases than in the reference case, driven by rising consumption in the electricity supply sector (Figure 93). Although electricity generators would produce less electricity in the carbon reduction cases than in the reference case, they would consume more natural gas, because relatively high-carbon coal would be replaced with relatively low-carbon natural gas. In the 9-percent-above-1990 (1990+9%) case, where the projected carbon price is relatively low, natural gas steadily replaces coal; but in the 1990-3% case, with a higher carbon price, renewable sources of generation begin to compete successfully with natural gas after 2010.

Figure 93. Natural Gas Consumption, 1996-2020



Note: Other uses are for residential, commercial, industrial, and transportation consumption.

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

The projections for natural gas use in the residential, commercial, industrial, and transportation sectors are almost always lower in the carbon reduction cases than in the reference case, because those sectors have significantly less opportunity to switch from higher-carbon fuels to lower-carbon natural gas. In the residential and commercial sectors there is very little coal use, and most oil consumption occurs in areas where natural gas pipelines are limited. In the industrial sector, under the best circumstances, gas consumption can only hold its own in the carbon reduction cases, as some boilers switch from coal to gas. In the transportation sector gas has difficulty competing because of the limited range of compressed natural gas vehicles. As a result, consumption of natural gas in these sectors is reduced from the reference case levels because of higher natural gas prices, which lead to conservation and the penetration of more efficient technologies.

The pattern of total gas consumption differs in the carbon reduction cases, depending on the carbon price (Figure 93). Higher carbon prices, as in the 1990-3% case, lead to a quick surge in natural gas consumption when the carbon price takes effect in 2005 and gas gains an advantage over coal for electricity generation. Later in the forecast the increase in gas consumption in the 1990-3% case is moderated, as renewables on the supply side and energy efficiency gains on the demand side begin to cut into the natural gas market. Moderate carbon prices in the 1990+9% case result in a steadier rise in natural gas consumption, ultimately to higher levels in 2020 than those expected in the 1990-3% case, because natural gas prices are not high enough to induce significant levels of conservation or competition from renewables. Low carbon prices in the 24-percent-above-1990 (1990+24%) case lead to an even slower, 1.8 percent annual rise in consumption, from 1996 to 2020.

From 1950 to the late 1980s, electricity generators were third among the major users of natural gas, after industrial and residential users. In the late 1980s, they began to slip into fourth position, after commercial users, where they are today. When oil and coal prices were declining in the late 1980s, gas prices were fairly constant. As a result, oil and coal took a larger share of the growing electricity generation market while gas use remained flat. Gas consumption continued to grow in the commercial sector, however, eventually surpassing electricity sector consumption.

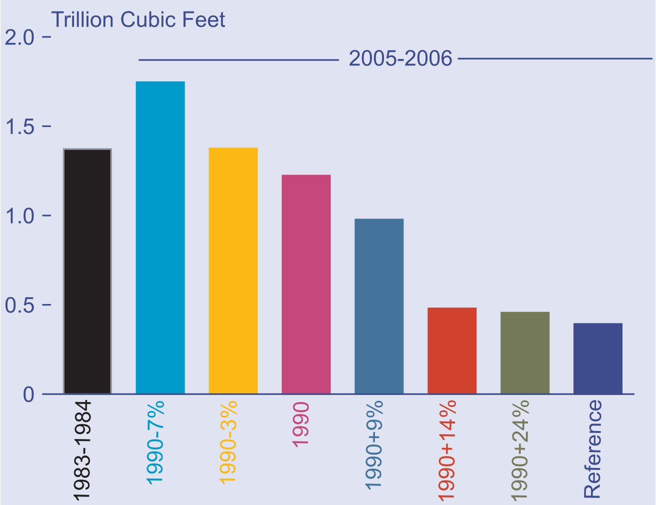
In the future, supply to electric generators is expected to become more important to the gas industry. In the reference, 1990+24%, and 14-percent-above-1990 (1990+14%) cases, electricity generators become the second largest consumers of natural gas, behind the industrial sector, by 2010. In the higher priced carbon reduction cases, they become the largest consumers of natural gas by 2010. Consumption of natural gas for electricity generation is projected to reach 12.2 trillion cubic feet in 2010 in the 1990-3% case, more than 5 trillion cubic feet higher than in the reference case and more than four times the 1996 level (Figure 93). Electricity generators can be expected to take a greater interest in natural gas pipeline capacity expansion by investing in some projects or by making long-term contracts. Pressure to merge gas and electricity companies could mount as the advantage of arbitraging the two markets becomes apparent. Electricity generators might also increase their direct ownership of natural gas resources or make long-term contracts with producers in efforts to reduce price volatility.

Natural Gas Production

In most of the carbon reduction cases examined here, natural gas production, in response to higher consumption and prices, is higher than it is in the reference case projections throughout the forecast period. Production patterns across the cases are similar to the consumption pattern: the 1990-3% case shows a sharper rise immediately after 2005, whereas the 1990+9% case shows a steadier but ultimately higher rise after 2011, and the 1990+24% case is slightly above the reference case. In 2010, production is projected to be 26.2 trillion cubic feet in the 1990-3% case, 25.9 trillion cubic feet in the 1990+9% case, and 24.1 trillion cubic feet in the 1990+24% case.

The imposition of carbon reduction targets in 2005 causes a sharp increase in natural gas production, due largely to increased consumption by electricity generators. The largest production increase is projected in the 7-percent-below-1990 (1990-7%) case (Figure 94), because competing coal prices rise faster than in any other case. The projected increase in natural gas production between 2005 and 2006 is 1.75 trillion cubic feet in the 1990-7% case, compared with only 0.39 trillion cubic feet in the reference case.

Figure 94. Increases in Natural Gas Production, 1983-1984 and 2005-2006



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Historically, the largest 1-year increase in gas production was 1.37 trillion cubic feet between 1983 and 1984 (Figure 94). However, in 1984 production was recovering to levels that already had been reached in 1982, and production in both 1983 and 1985 was down from the previous year. In contrast, the levels expected in 2005-2007—while not unlikely—have never before been reached. Increasing natural gas consumption during the initial phases of a carbon emissions reduction program may be the biggest challenge facing the oil and gas industry, and careful planning will be required.

Sufficient natural gas resources are available, however, and infrastructure can be made available, if the price is right.

All the carbon reduction cases would require more natural gas wells to be drilled to reach the expected higher production levels. In 1996 about 9,100 successful gas wells were drilled. In the reference case, some 12,000 are expected by 2010. The largest annual increase required in any of the carbon reduction cases is less than 700 wells. A 700-well increase could easily be handled by the drilling industry, considering that the number of successful gas wells increased by more than 2,000 from 1996 to 1997, when prices increased from $1.55 in 1995 to $2.23 in 1997. The stimulating effect of prices on drilling can also be seen in the 1990-3% case, which projects the highest number of gas wells in 2010, because gas wellhead prices are only a few cents below the 1990-7% case and oil wellhead prices are higher.

Although the number of available drilling rigs has been declining since 1982, price increases are a powerful incentive for increased drilling and the purchase of new drilling equipment. The number of available drilling rigs increased by almost 14 percent annually between 1974 and 1982—from 1,767 to 5,644—as natural gas prices more than quadrupled in real terms.[71] About 1,600 drilling rigs were available in the United States in 1996. To support the increased drilling in the carbon reduction cases, the number of available drilling rigs is also expected to rise, especially between 2005 and 2010, when 2-percent increases in rig construction are projected in some years. Given the historical response to rising prices, rig availability is unlikely to be a problem in the carbon reduction cases.

Increased drilling produces higher reserves in the carbon reduction cases than the reference case, but not until after 2010. Initially, increased consumption of natural gas depresses reserves in the carbon reduction cases, compared with the reference case projection, because production exceeds reserve additions. After 2010, however, natural gas reserves in the carbon reduction cases begin to exceed reserves in the reference case, pulled up by the higher prices. In all the cases, reserves peak late in the forecast and then begin to decline. The peak year for reserves is important, because a decline in reserves indicates that production is exceeding reserve additions. When that happens, wellhead prices tend to rise because of depletion effects. Reserves peak later in the higher carbon price cases, as higher wellhead prices sustain drilling and discoveries over a longer period. In the 1990-3% and 1990+9% cases, reserves peak in 2018, compared with 2013 in the reference case and 1990+24% case. The highest peak is projected in the 1990-7% case, at 195.5 trillion cubic feet of reserves in 2018. Projections

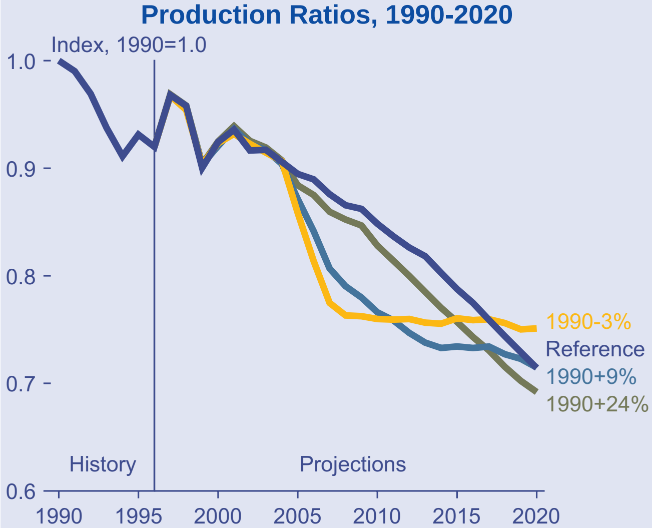
[71] T.A. Stokes and M.R. Rodriguez, "44th Annual Reed Rig Census," *World Oil* (October 1996).

of reserve levels depend on the assumed levels of natural gas resources and, as such, are highly uncertain, particularly in the offshore regions of the lower 48 States.

In general, increased reserves indicate that a mineral industry is well prepared to serve its customers; however, reserves must be placed in the context of production to gauge their real adequacy. Reserve-to-production (RP) ratios provide a measure of the adequacy of reserves. In this analysis, RP ratios generally are projected to fall faster in the carbon reduction cases than in the reference case, because production exceeds replacement of reserves (Figure 95). The path of RP ratios over the forecast is heavily influenced by the production path. When production increases steeply in the 1990-3% case the RP ratio drops steeply, whereas in the 1990+24% case the RP ratio drops more steadily to lower ultimate levels. In 1996, the RP ratio for natural gas was 8.3. In the reference case, it is projected to fall to 6.4 in 2020. In the 1990+24% case, the RP ratio in 2020 is slightly lower than in the reference case and is at the lowest level of any year in the forecast. In the 1990-3% and 1990+9% cases, the RP ratio in 2020 exceeds the reference case projection (Figure 95). Thus, when a higher carbon price is projected, the adequacy of natural gas reserves improves relative to that projected in the reference case, because higher gas prices are expected to lead to more reserve additions.

Most types of natural gas production are projected to be higher in the carbon reduction cases than in the reference case, with the exception of associated-dissolved (AD) and Alaskan gas. AD gas production is a function of oil production, which is expected to be lower in the carbon reduction cases than in the reference case (see the "Oil Production" section below). While increasing in all cases, Alaska's production of natural gas is expected to be lower in the carbon reduction cases, because the market for Alaskan gas is limited mostly to the State. Electricity generators in Alaska are already more heavily dependent on natural gas than coal, and their opportunities to switch from coal to gas are limited. So, electricity generators reduce gas consumption. Although not included in this analysis, the market for Alaskan natural gas could grow through increased exportation of liquefied natural gas, manufacturing of liquids from natural gas (the Fischer-Tropsch process), increased industrial manufacturing, or methanol manufacturing.

Figure 95. Index of Natural Gas Reserve-to-Production Ratios, 1990-2020



Sources: **History:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996*, DOE/EIA-0216(96) (Washington, DC, November 1997), and preceding reports. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE. D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW. D080398B.

Employment in the oil and gas industries generally has fallen in recent years, as oil production has declined and productivity has increased. According to the U.S. Bureau of Labor Statistics, employment in the oil and gas extraction industries declined from 400,000 employees in 1988 to 322,000 in 1996, a reduction of approximately 20 percent. Over the same period, total oil and gas production dropped from 34.9 quadrillion Btu to 33.0 quadrillion Btu, a reduction of only 5 percent. Rising productivity accelerated the decline in employment relative to the decline in production.

In the reference case, higher natural gas production is projected to more than offset lower oil production, leading to a total oil and gas production level of 38.6 quadrillion per year Btu by 2020. Although employment in the oil and gas industries is not included in the projections for this analysis, it is reasonable to expect that the increase in production would at least reduce the rate of decline in employment. In the 1990+9% case, total oil and gas production in 2020 is projected to be 2.1 quadrillion Btu (about 5 percent) higher than in the reference case, despite a reduction of 0.5 quadrillion Btu in oil production. Thus, the projection for the 1990+9% case implies that there would be more workers in the natural gas industry in 2020.

The patterns of U.S. natural gas production projected in the carbon reduction cases differ among the six onshore and three offshore producing regions, depending on consumption and available resources. In the largest producing regions, the Rocky Mountain and Gulf Coast onshore and Gulf Coast offshore, production rises throughout the forecast in the reference case, because significant amounts of resources are located in those regions, and technology improvements make more of the resources available for production in the projection period—particularly, unconventional resources and conventional resources at depths greater than 10,000 feet. In the three medium-sized onshore regions, production peaks during the forecast in the reference case and declines as production becomes more costly. In the two least productive regions, the West Coast and Pacific offshore, production generally falls throughout

Natural Gas Supply Issues

Uncertainty regarding estimates of the Nation's natural gas resources has always been an issue in projecting production. Although this study relies on resource estimates made by the U.S. Geological Survey (USGS) and Minerals Management Service (MMS), some uncertainty surrounds those estimates. Although many analysts believe that the USGS estimates are too high, an April 1998 study by the Gas Research Institute (GRI)[a] contends that the industry has "significantly underestimated" the growth potential of existing fields and should look to the Midcontinent, onshore Gulf Coast, East Texas, and San Juan Basin for reserve growth. GRI has increased its reserve estimates for those areas but maintains that assessing the actual amounts remains a difficult task. Uncertainty is a particular problem in the offshore area (which the industry hopes will provide significant supplies) because not much historical data is available for offshore production. Not all of the industry's original hopes may be realized, however. For example, the sub-salt area, which until recently was regarded as a promising supply source, is no longer considered to be as promising.

Another concern about supply availability is access to public land for drilling. Drilling moratoria have placed offshore areas in the eastern Gulf of Mexico, North Carolina, and California off limits, and drilling is limited in some areas of the West because of concern about emissions. Substantial resources in the Arctic National Wildlife Refuge (ANWR)[b] are also restricted from drilling, although the current inability to market natural gas from northern Alaska renders the accessibility issue moot.

In addition to concerns about supply availability, there is widespread speculation in the industry as to whether the level of production that would be needed to meet the hefty increases in demand projected in various carbon reduction scenarios could be achieved, given current worldwide shortages of offshore rigs and skilled personnel. Virtually every available offshore rig was in use throughout 1997, and capacity expansion has been limited by uncertainty surrounding the actual demand for new rigs. The lead time for construction of new rigs is 2 to 3 years, and costs range from $115 million for a 350-foot jack up to $325 million for a deepwater semisubmersible.[c] Considerable training is needed to develop a workforce, and many people are reluctant to enter the workforce because of its cyclical history and their consequent fear of future layoffs. In addition, there are concerns about the adequacy of the infrastructure to move gas from offshore drilling platforms to the shore.

To address these uncertainties, several studies are being undertaken. For example, former Secretary of Energy Federico Peña commissioned the National Petroleum Council (NPC) to undertake a study of whether the industry will be able to respond to meet projected demands,[d] and the Natural Gas Supply Association (NGSA) is working on a report that will analyze whether the industry can meet increased demand projections without increasing wellhead prices.[e]

Royalty issues are also of concern. The Assistant Secretary of the Interior for Land and Minerals Management, Robert L. Armstrong, raised the issue of a possible increase in the deepwater royalty rate to 16.67 percent from 12.5 percent after the current "royalty holiday." Although the proposal has not been supported by Congress, the uncertainty about royalty relief that stems from any talk about changes could place a damper on investment.

Despite the above concerns, considerable investment is being made in the industry. According to Arthur Andersen's 10th annual "U.S. Oil & Gas Industry Outlook Survey," executives of most U.S. exploration-and-production companies plan to increase spending in 1998.[f] As an example, Shell has recently announced plans to spend nearly $1 billion to develop three oil-and-gas fields in the deepwater Gulf of Mexico.[g]

Clearly, there are conflicting opinions throughout industry as to whether steep increases in production can be achieved in a timely fashion, even with significant increases in wellhead prices. In order for this to happen, the industry first needs to be confident that the demand will be there, so that the necessary investments in infrastructure, rigs, drilling, and manpower development can be made in time.

[a] *Assessment and Characterization of Lower-48 Oil and Gas Reserve Growth*, prepared by Energy and Environmental Analysis, Inc. for the Gas Research Institute (Chicago, IL, April 1998).

[b] ANWR resources are not included in this analysis.

[c] "Simmons: Offshore Rig Shortage Looms," *Oil and Gas Journal* (April 27, 1998), p. 24.

[d] "Producers Question Studies Showing Rising Gas Demand But Flat Prices," *Inside F.E.R.C.'s Gas Market Report* (May 15, 1998), p. 2.

[e] "Concerned About Prices, NGSA To Throw Shadow Over Rosy Supply Pictures," *Inside F.E.R.C* (May 11, 1998), p. 7.

[f] "E&P Companies Plan To Boost Spending Despite Variety of Concerns—Study," *Inside F.E.R.C.'s Gas Market Report* (December 26, 1997), p. 9.

[g] "Shell To Spend $1 Billion To Develop Three Gulf Deep-Water Discoveries," *Inside F.E.R.C.'s Gas Market Report* (April 3, 1998), p. 9.

the forecast, as a small resource base precludes significant responses to higher prices. Regional production in the carbon reduction cases is generally higher than in the reference case because prices are higher. In regions where production peaks during the forecast, production tends to peak sooner in the carbon reduction cases, because more gas is produced earlier.

Natural Gas Imports

Natural gas imports are projected to be higher in all the carbon reduction cases than in the reference case, as the industry works to meet rising demands for natural gas. In 2010, net natural gas imports are projected to be 4.7 trillion cubic feet in the reference case and up to 5.7 trillion cubic feet in the carbon reduction cases. Net imports are highest in the cases with high carbon prices, where imports surge as the carbon prices are imposed and remain at higher levels than those projected in the reference case. However, by the end of the forecast, the highest levels of net imports are expected in the 1990-3% case, rather than the 1990-7% case, because consumption is projected to be higher in the 1990-3% case.

In most of the carbon reduction cases, the majority of the higher imports come from Canada in 2010, but in the 1990-7% and 1990-3% cases at least half of the increase comes from Mexico. Even though Canada would be subject to its own carbon restrictions, it has a large enough resource base to increase both domestic consumption and exports. The Canadian Gas Potential Committee estimated in 1997 that the Western Canada Sedimentary Basin contained 263 trillion cubic feet of marketable gas.[72] In 2010 Natural Resources Canada projects Canadian natural gas consumption at 3.6 trillion cubic feet, up 600 billion cubic feet from 1995.[73] If carbon reduction targets were imposed, Canada's gas consumption would likely be higher. For example, if gas consumption in Canada were 10 percent higher in 2010 as a result of carbon restrictions, as projected for the United States in the most stringent carbon reduction cases, it would reach 4.2 trillion cubic feet in 2010. Even at that level, however, U.S. prices are expected to be high enough to continue the flow of imports from Canada.

In the carbon reduction cases, Mexico is a net exporter of natural gas to the United States in 2010, whereas it is a net importer in the reference case. Mexico begins to export gas to the United States in the carbon reduction cases in response to higher consumption and higher wellhead prices. Net imports of liquefied natural gas (LNG) reach one-third of a trillion cubic feet annually in all the carbon reduction cases but do so more quickly in the cases with higher projected carbon prices.

Natural Gas Pipelines

Interstate natural gas pipeline capacity additions would need to be higher in the carbon reduction cases than they are in the reference case projections, but they are expected to be manageable. In the reference case, cumulative additional natural gas pipeline capacity crossing the 12 regions used for this analysis are projected to increase to 52.5 trillion cubic feet of design capacity in 2010 from the 1996 capacity of 43.0 trillion cubic feet. The most significant increase is projected from 1998 to 2001, when capacity increases by 6.3 trillion cubic feet because of increasing consumption in the Midwest and Northeast not because of carbon reduction policies. During the 1998-2001 period, the Alliance pipeline is expected to come down to the Midwest from Canada, and the Maritimes / Northeast and Portland Natural Gas Transmission System pipelines are expected to come down from Sable Island in Canada to the northeastern United States. After 2001, pipeline capacity is projected to increase more gradually through 2010.

In the carbon reduction cases, the largest 1-year increase in pipeline capacity after 2001 is seen from 2011 to 2012 in the 1990+9% and 1990+14% cases, when capacity increases by 1.6 trillion cubic feet. The capacity increases in this period are primarily out of Texas, Louisiana, and Oklahoma, through the South, to the southern coastal States in response to growing consumption. The largest increase soon after imposition of the carbon price is from 2006 to 2007 in the 1990-3% case, when capacity is projected to increase by 1.4 trillion cubic feet. The increase is mainly from west to east, from the Texas-Oklahoma-Louisiana region to the Middle South.

Historically, the largest recent annual increase in pipeline capacity was 1.6 trillion cubic feet from 1991 to 1992, partly because of the construction of four major pipelines into California from the Mountain States (Kern River, Mohave, El Paso, and Transwestern) and two major pipelines out of Canada (Great Lakes into the Midwest and Iroquois into the New York / New England area). In view of the historical and expected near-term increases in capacity, capacity expansion is not likely to be a problem in any carbon reduction scenario, as long as pipeline requirements are known 2 to 3 years in advance.

Natural Gas Prices

Natural gas prices are higher in the carbon reduction cases than in the reference case, both at the wellhead and at the burner tip. At the wellhead, higher production to satisfy increased natural gas consumption, in the face of increasingly expensive resources, boosts prices. At the burner tip, adding carbon prices to resource costs could more than double some end-use prices.

In the reference case, lower 48 wellhead natural gas prices are projected to rise from $2.24 per thousand cubic feet in 1996 to $2.33 in 2010 in 1996 dollars (Figure 96). The 2010 wellhead prices are more than 40 cents per thousand cubic feet or 19 and 29 percent higher in the 1990-3% and 1990+9% cases, which project higher consumption and the use of increasingly expensive resources. The highest wellhead prices in 2010 are seen in the 1990-7% case at $3.03 per thousand cubic feet, where carbon prices are highest in 2010.

The pattern of natural gas wellhead prices is similar to the consumption and production patterns (see above). In the reference case, prices rise gradually, but in the carbon reduction cases prices rise quickly after a carbon

[72]Canadian Gas Potential Committee, *Natural Gas Potential in Canada* (Calgary: University of Calgary, 1997), Figure 1.2.
[73]Calculated from Natural Resources Canada, *Canada's Energy Outlook 1996-2020* (Ottawa: Natural Resources Canada, 1997), Annex C.

price is imposed in 2005. In the cases with higher projected carbon prices, gas prices rise more quickly, then flatten out as energy conservation on the demand side and renewable energy production on the supply side slow the overall rate of growth in natural gas consumption. When moderate carbon prices are projected, gas prices rise more steadily but ultimately reach higher levels.

Natural Gas Pipeline Expansion

There are three ways of increasing pipeline capacity. The simplest and least expensive is to increase throughput by increasing compression at compressor stations. The second is through a process called "looping," in which parallel pipe is laid next to existing pipe to increase capacity along an existing route. The third, and most costly, is to build new pipe, usually entailing additional costs for land and / or right-of-way.

Two key criteria must be met in order for an expansion project even to be proposed: (1) the existence of demand must be shown, and (2) the project must be proven to be financially viable. Four steps are needed to bring a project to fruition: (1) an open season of 1 to 2 months during which bids for the proposed capacity are solicited and received, (2) a planning stage of 3 to 5 months, (3) filing with the Federal Energy Regulatory Commission (FERC) for approval, with an average time of 15 months (ranging from 5 to 18 months), and (4) an actual construction stage, which averages 6 to 9 months. Barring unforeseen delays, capacity can be added with a lead time of 2 to 3 years. Problems that can slow down the process include the filing of environmental impact statements and acquiring necessary approvals, and changes in market conditions (such as the changing market conditions that affected the Altamont project, which was approved in 1990 but still has not been constructed). FERC has seen a significant increase recently in the number of comments and protests received on proposed expansion projects. Another potential problem is competition between two pipelines for expansion to serve the same market, such as the recent competition to move supplies from Western Alberta, Canada, into the Midwest.

Greater increases in pipeline capacity than those projected in the carbon reduction cases are likely between now and 2000. More than 116 expansion projects have already been proposed. For the 71 projects for which preliminary estimates are available, the estimated total costs exceed $11 billion. In 2000 alone, $4.6 billion in expenditures is anticipated, as several major projects may be completed.[a] The added capacity is needed to provide access to new and expanding production areas, such as Canada and the deep offshore, and to accommodate shifts in demand patterns, such as new demands for natural gas to replace electricity generation capacity lost as a result of nuclear retirements.

Although there is speculation within the industry as to whether the needed expansions can occur, two factors support an optimistic outlook. The first is changes in FERC policy, which now leans more toward letting the pipelines assume more risk rather than requiring firm contracts to be in place before approving an expansion. This may work to speed up the approval process. The second is projected increases in natural gas demand, independent of the Kyoto Protocol. Demand growth is already anticipated to result from electric utility restructuring activities in a growing number of States, retirements of nuclear facilities, and measures included in the President's Climate Change Technology Initiative (a $6.3 billion initiative), which will proceed regardless of the fate of the Kyoto Protocol. If the anticipated increases in demand do materialize, they could provide the impetus for much of the capacity increase that would be needed in the event that the Kyoto Protocol is ratified.

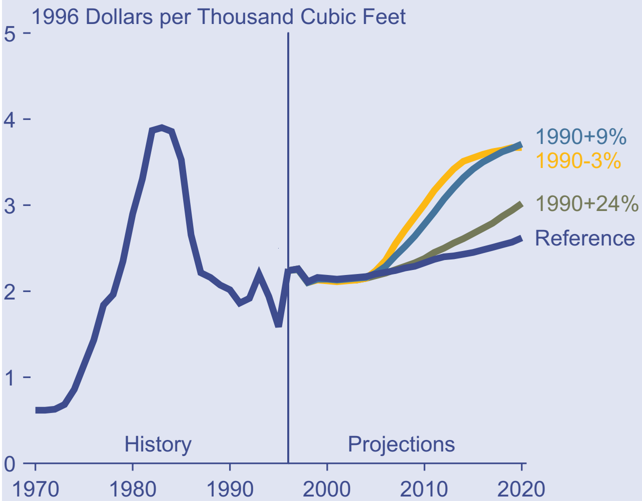
On the other hand, financial considerations are creating some uncertainty about the responsiveness of the pipeline industry. A major issue is whether the economic climate for investment will continue to be favorable. Pipeline owners are claiming that they currently face considerable risk because of increased competition and the threat of capacity turnback. While the Natural Gas Supply Association (NGSA) contends that the FERC's current policy for determining pipeline returns on equity is fair and properly accounts for the risk faced by the pipeline industry, the Interstate Natural Gas Association of America (INGAA) contends that the Commission's generic method artificially lowers allowed returns, and that rates should be calculated on a case-by-case basis. Pipeline executives contend that the 12- to 13-percent average rate of return for pipelines in 1996 was far lower than the 20-percent rate earned by most public companies.[b] In response to the industry's concerns, the FERC is currently evaluating possible changes in the method used to calculate pipeline returns. As even more risk is associated with the levels of expansion forecast in the carbon reduction cases, a key question is, "Who will assume the added risk—utilities that need the gas, other consumers willing to contract for gas, or the pipeline companies?"

Despite the obvious uncertainties, recent history shows that the industry can handle expansions of the same order of magnitude as those being projected as a result of the Kyoto Protocol. Changes in the pipeline industry between now and the time of the rapid capacity expansions that are expected to be needed to support electricity suppliers after the enactment of carbon reduction targets will be key to the industry's ability to respond. This is one of the issues that the upcoming NPC study commissioned by former Secretary of Energy Federico Peña will be addressing. Several other industry studies are underway to evaluate the industry's ability to respond, including an INGAA study that "will be looking at what needs to be done for the pipeline industry" to achieve a market of 30 trillion cubic feet by 2010.[c]

[a]Energy Information Administration, Office of Oil and Gas, *EIAGIS Natural Gas Geographic Information System Natural Gas Proposed Construction Database* (Washington, DC, preliminary as of April 1998).

[b]"NGSA: Return-on-Equity Fair Despite Protests by Pipelines," *Natural Gas Week* (March 9, 1998), p. 6.

Figure 96. Natural Gas Wellhead Prices, 1970-2020

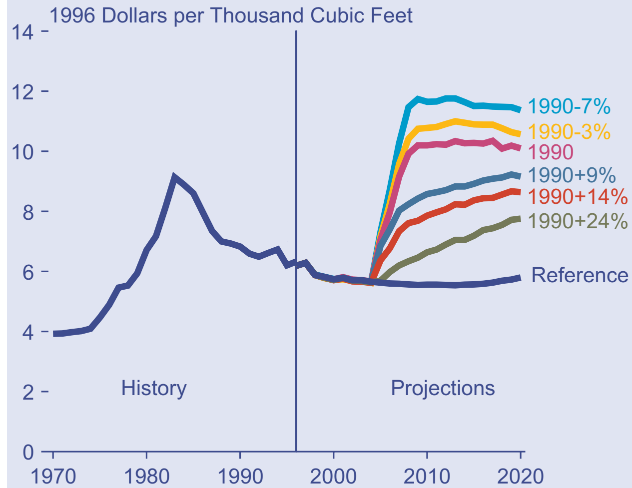


Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

On a regional basis, access to end-use markets heavily influences wellhead prices. Some of the lowest wellhead prices are seen in the Rocky Mountain region, where access to eastern markets is limited by pipeline constraints. This is balanced by wellhead prices in the two largest producing regions in this study, the Gulf Coast onshore and offshore, which have prices slightly above the national average in 1996. Wellhead prices are currently higher in the Northeast region than any other, where demand is significant and growing. Regional prices are generally higher in the carbon reduction cases, because of higher demand. Though more exaggerated, the pattern of growth across regions is much the same as in the reference case.

The projected end-use prices for natural gas in the carbon reduction cases are double the prices in the reference case at their peak in the most extreme cases. The main components of end-use prices are the wellhead price, the carbon price, and transmission and distribution margins. On a percentage basis, residential prices are the least affected by the imposition of carbon prices, and the prices to electricity generators are the most affected (the projected carbon price is almost the same for both sectors, but gas prices are significantly higher in the residential sector). In 1996, natural gas prices for end users in the residential sector, which has the largest number of end-use customers, were $6.37 per thousand cubic feet. In the 1990-3% case, residential prices are expected to peak in 2013 at $11.31 per thousand cubic feet (in 1996 dollars), compared with $5.71 in the reference case (Figure 97). The difference is almost entirely attributable to the carbon price, which adds $4.20 to residential gas prices in 2013. Wellhead prices and transmission margins are also projected to be higher, however, because of higher in total gas consumption even though residential consumption is

Figure 97. Delivered Natural Gas Prices in the Residential Sector, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

lower. In the residential sector, margins for distribution services are higher because fixed costs must be spread over a smaller consumption base. In the 1990-7% case, residential prices are projected to peak at $12.10 per thousand cubic feet in 2013, because this case has the highest carbon prices. End-use prices in the carbon reduction cases follow a pattern similar to the pattern of carbon prices.

The story is much the same for the electricity supply sector, where the most growth in consumption is expected, except that the projected difference between wellhead and end-use margins is much smaller (less than 10 cents per thousand cubic feet) in the 1990-3% case in 2010. The differences in margins is not as high as in the residential sector because higher electric generator consumption allows gas utilities to spread their fixed costs over a larger volume of gas. In 1996, delivered prices to electricity generators were $2.70 per thousand cubic feet. At their peak in 2014, prices in the 1990-3% case are projected to be $8.27 per thousand cubic feet, compared with $3.05 in the reference case. As in the residential sector, the higher the carbon price, the higher the end-use price.

End-use prices for natural gas are affected by their distance from the sources of supply. End-use prices in the Texas-Louisiana region are currently less than half of prices in New England, for example. Although New England currently has the highest average natural gas end-use prices, prices are expected to be highest in the Mid-Atlantic region in a few years, as new pipeline projects are completed into New England and as consumption for electric generation increases. Regional prices are generally higher in the carbon reduction cases than in the reference case, because of higher demand. They show much the same pattern of growth as in the reference case.

Oil Industry

Oil is a larger source of energy than natural gas. Nearly 40 percent of U.S. energy comes from oil, most of which is used to fuel our vehicles and industry. Gasoline and diesel oil fuel more than 200 million vehicles, one for every 1.3 people in the country. Almost half of our oil was imported by tanker ship from Venezuela, Mexico, Saudi Arabia, and other countries at a cost of more than $60 billion in 1996. The rest is produced domestically, mainly in Texas, Alaska, Louisiana, and California, and shipped by pipeline and tanker. With the exception of residual fuel oil, this easily moved, universally-available liquid tends to cost more per Btu than other forms of energy.

In 1996, oil combustion produced 621 million metric tons of carbon emissions in the United States, over two-fifths of the total and more than those produced from burning coal. The transportation sector was responsible for the major share of those emissions, almost three quarters, followed by industrial and residential emissions in order of magnitude. In 2010, if no carbon reduction measures are put in place, emissions from oil combustion are expected to be more than 130 million metric tons higher than they were in 1996, although their share of the total will be slightly lower.

U.S. oil consumption is expected to increase between 1996 and 2010 in the reference case, despite a projected decline in domestic oil production. Most of the growth is expected in the transportation sector, where oil consumption is projected to increase by almost 30 percent from 1996 to 2010. About half the increase comes from light-duty vehicle travel and more than 20 percent from increased air travel. Oil use in the industrial sector is projected to increase by about 15 percent between 1996 and 2010, with more than three-fifths of the increase coming in refining and petrochemical feedstocks. As a result of these increases, oil's share of the energy market will increase slightly over time.

While petroleum production from conventional sources in the lower 48 States and in Alaska is expected to fall between 1996 and 2010, enhanced oil recovery and offshore production are expected to increase, but not enough to prevent an overall decline. Net imports of crude oil and petroleum products are projected to rise to fill the gap between consumption and production. In the reference case, almost three-fifths of the U.S. oil supply in 2010 is projected to come from imports, with about three-fourths of total imports entering the country in the form of crude oil and the rest as finished or unfinished products. Gross refinery margins are projected to increase on the strength of increased refinery throughput and capacity expansion. End-use prices show little change in the reference case, as increases in world oil prices are balanced by assumed reductions in motor fuel taxes. Federal taxes on gasoline and diesel fuel are assumed to stay constant in real dollar terms, which would mean a decline in nominal terms.

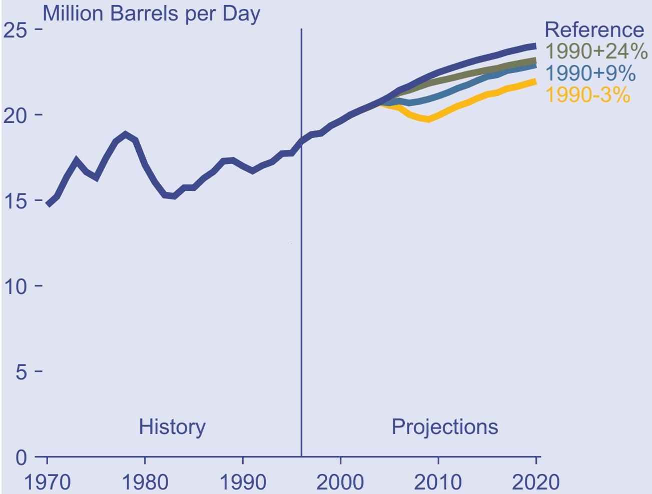
Policies aimed at reducing carbon emissions would lead to lower consumption, production, imports, and refinery margins for the U.S. oil industry. On the other hand, end-use prices and market share would be higher. Higher end-use prices—reflecting new carbon prices—would reduce consumption in the carbon reduction cases, lessening the need for domestic production and foreign imports. Refinery margins in those cases would be lower, because consumption of petroleum products and expansion of refinery capacity are projected to be lower than in the reference case. Despite the lower levels of oil consumption projected in the carbon reduction cases, oil's share of the energy market would be higher as a result of an even larger drop in coal use. For example, in the 1990-3% case, oil is projected to claim 41 percent of the domestic energy market in 2010 and coal just 7 percent, as compared with their respective 38-percent and 22-percent shares in 1996.

Oil Consumption

Oil consumption is expected to be lower in the carbon reduction cases than in the reference case (Figure 98), with most of the difference in the transportation sector. Current petroleum product consumption is at about the previous peak level of consumption reached 20 years ago. In the reference case, consumption rises from 18.5 million barrels per day in 1996 to 22.5 million barrels per day in 2010. In the carbon reduction cases, higher carbon prices overwhelm lower crude oil prices and lead to lower levels of oil consumption in 2010—22.0 million barrels per day in the 1990+24% case and 20.0 million barrels per day in the 1990-3% case. Consumption in the transportation sector is particularly affected. More than 65 percent of the difference between the reference and the carbon reduction cases in 2010 is in the transportation sector.

In the reference case, petroleum consumption rises throughout the forecast. Consumption also rises continually throughout the forecast in the carbon reduction case with the lowest projected carbon prices, the 1990+24% case. In the other cases, consumption declines during the 2005-2009 period after the carbon price is imposed. The higher the carbon price, the greater the decline in consumption. After 2009, consumption rises in all cases through the rest of the forecast, because highway and air travel increase while carbon prices change modestly.

Figure 98. Petroleum Consumption, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

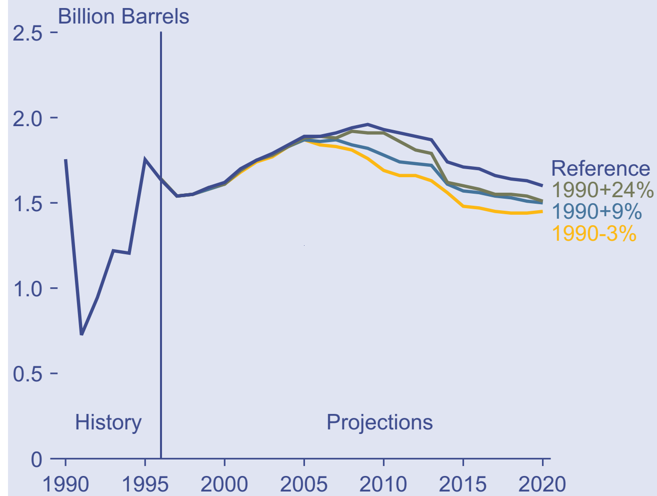
Oil use in the transportation sector is expected to absorb the largest share of the projected declines between 2005 and 2009, accounting for more than 85 percent of the total drop in oil consumption in the three most stringent carbon reduction cases, with smaller reductions in the residential, commercial, and industrial sectors. In the 1990-3% case, transportation consumption falls from 14.2 million barrels per day in 2004 to 13.5 million barrels per day in 2009, followed by a continuing increase to 15.0 million barrels per day in 2020. During the period of declining consumption, high carbon prices produce rapid increases in transportation fuel prices. After 2009, when consumption begins to rise, fuel prices in the transportation sector are generally level or declining, as the carbon prices decline.

Oil Production

U.S. oil production declines steadily throughout the forecast both in the reference case and in the carbon reduction cases, but lower consumption and diminishing oil reserves in the later years of the carbon reduction cases lead to larger production declines. In the reference case, crude oil production is projected to drop from 6.5 million barrels per day in 1996 to 5.9 million barrels per day in 2010, compared with 5.8 million barrels per day in the 1990+24% case and 5.7 million barrels in the 1990+9% and 1990-3% cases in 2010. The higher the carbon price, the lower is the crude oil price, the less is the buildup in reserves, and the lower is oil production, because the higher carbon prices overwhelm lower crude oil prices.

Domestic oil drilling activity rises steadily in the reference case and in the least stringent carbon reduction case. In the more stringent cases, drilling generally increases, but declines are projected in the middle years

Figure 99. Lower 48 Crude Oil Reserve Additions, 1990-2020



Sources: **History:** Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1996*, DOE/EIA-0216(96) (Washington, DC, November 1997), and preceding reports. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE. D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW. D080398B.

of the forecasts, when high carbon prices depress oil prices. The lowest levels of drilling activity are seen in the cases with the highest projected carbon prices, which result in the lowest wellhead prices.

Despite the projections of increased oil drilling both in the reference case and in the carbon reduction cases, oil reserves are not expected to rise over the forecast period. Declining reserves are projected in all the cases, because reserve additions do not exceed production. For example, all the carbon reduction cases show reserve additions of only 1.9 billion barrels in 2005 (Figure 99), when production is projected to be about 2.2 billion barrels for the year. Thus, oil reserves decline. In the reference case, higher oil prices sustain enough drilling for annual reserve additions to peak at 2.0 billion barrels in 2009. In the more stringent carbon reduction cases, however, declining oil prices cause reserve additions to fall after 2005. The inability of the oil industry to replace reserves has less effect on oil prices than the inability to replace gas reserves has on gas prices, because oil prices are set in a world market, and because the RP ratios for oil are actually projected to rise.

Oil RP ratios, which are indicative of the industry's ability to sustain production, rise over the forecast both in the reference case and in the carbon reduction cases, as oil production falls more quickly than reserves. The RP ratio in the reference case rises from 7.1 in 1996 to 7.3 in 2010. RP ratios in the carbon reduction cases are slightly lower, because the low oil prices in the carbon reduction cases depress reserve additions more than production.

Most types of oil production are projected to be lower in the carbon reduction cases than in the reference case, and most of the lower production in the carbon reduction cases is in lower 48 onshore conventional and enhanced oil recovery production—the two types of production that are the most responsive to lower oil prices. In 2010, conventional onshore lower 48 oil production is 90,000 barrels per day lower in the 1990-3% case than in the reference case, 60,000 barrels per day lower in the 1990+9% case, and 20,000 barrels per day lower in the 1990+24% case. Enhanced oil recovery is 50,000 barrels per day lower in the 1990-3% case, 40,000 barrels per day lower in the 1990+9% case, and 10,000 barrels per day lower in the 1990+24% case.

Regionally, oil production is generally lower in the carbon reduction cases than in the reference case. It is significantly lower in the Southwest (western Texas and eastern New Mexico), in the Rocky Mountains, and in the offshore Gulf Coast, which are the largest producing regions. In the 1990-3% case, for example, the projected production in 2010 in each of these regions is 40,000 barrels per day less than projected in the reference case. In the Midcontinent region (Kansas, Oklahoma, and Arkansas), oil production is slightly higher in the more stringent carbon reduction cases than in the reference case, because increased drilling for gas in the carbon reduction cases leads to more oil discoveries and greater oil production; however, the peak difference is only about 10,000 barrels per day.

Regional crude oil prices are most affected by the quality of the crude oil. West Coast crude oil prices are generally lower than prices in the rest of the Nation because the density of West Coast crude oils is higher. Dense crude oils contain less of the higher-valued light products, like gasoline or diesel fuel, so their value is lower. Crude oil prices are lower in the carbon reduction cases, but the relationships among regional prices is the same as in the reference case.

Oil Imports

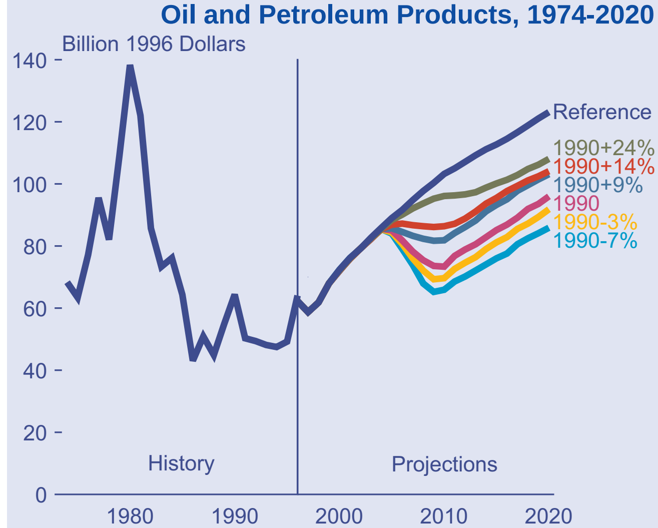
The projections for net imports of crude oil and petroleum products are lower in the carbon reduction cases than in the reference case, because oil consumption is projected to be lower, with domestic sources providing a greater share of the Nation's oil needs. As a share of total consumption, net oil imports reach 59 percent in 2010 in the reference and 1990+24% cases but only 54 percent in the 1990-3% case and 56 percent in the 1990+9% case. In all the cases, the projected import levels are above current levels, which are the highest yet recorded. The total value of net oil imports in 2010 is $103 billion in the reference case but only $96 billion in the 1990+24% case, $82 billion in the 1990+9% case, and $70 billion in the 1990-3% case (Figure 100). Both values are well below the 1980 peak of $138 billion (in 1996 dollars). Even in 2020, the total projected expenditures for oil imports in the reference case are only $123 billion.

Net crude oil imports rise steadily throughout the forecast in the reference case and in the 1990+24% and 1990+9% cases. In the 1990 stabilization, 1990-3%, and 1990-7% cases, however, net crude oil imports begin to fall when the carbon price is first imposed, bottoming out in 2009 before beginning to rise again. Imposition of relatively high carbon prices causes oil consumption—and imports—to fall temporarily in these cases.

Net petroleum product imports are affected more strongly than crude oil imports in the carbon reduction cases, because imported crude oil is generally more valuable to U.S. refiners than imported products inasmuch as profits are maximized only at high rates of refinery utilization. In the reference case, net product imports rise from 1.1 million barrels per day in 1996 to 3.1 million barrels per day in 2010. In comparison, the corresponding increases are only 70,000 barrels per day in the 1990-3% case, 760,000 barrels per day in the 1990+9% case, and 1.64 million barrels per day in the 1990+24% case. In the reference case and in the less stringent carbon reduction cases, net petroleum product imports exceed the historic 1973 peak of 2.8 million barrels per day at some time during the forecast, beginning as early as 2009 in the reference case, for example.

In the two most stringent reduction cases, unlike the other cases, product imports fall from 2004 through 2008 because of a decline in petroleum product consumption, and net product imports stay below the historic peak through 2020. In the 1990-7% case, net product imports remain below even their 2004 peak of 2 million barrels per day through 2020.

Figure 100. Net Expenditures for Imported Crude Oil and Petroleum Products, 1974-2020



Sources: **History:** Energy Information Administration, *Monthly Energy Review June 1998*, DOE/EIA-0035(98/06) (Washington, DC, June 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Petroleum Products

Consumption of almost all the individual petroleum products is projected to be lower in the carbon reduction cases than in the reference case, because higher prices lead to lower demand. Gasoline consumption in 2010 is 3 percent lower in the 1990+24% case than in the reference case, 8 percent lower in the 1990+9% case, and 15 percent lower in the 1990-3% case, in direct response to the projected carbon prices. Distillate, diesel, and jet fuel consumption levels are also lower. Residual fuel is the least affected, because it is projected to compete successfully with natural gas and coal in the industrial sector. The projected consumption of residual fuel in 2020 is actually higher in the 1990+9% case than in the reference case because of higher industrial demand.

In 2010, the projected product shares of total petroleum consumption are approximately the same in the reference, 1990+24%, 1990+9%, and 1990-3% cases: 43 percent for gasoline, 18 percent for distillate, 11 percent for jet fuel, 4 percent for residual fuel, and 24 percent all other products. The gasoline and jet fuel shares are slightly lower in the 1990-3% case, with slightly higher shares for the other, mostly heavier products. Purely on the basis of carbon content, consumption might be expected to move away from the heavier products, which have more carbon, and toward the lighter products; however, sector-by-sector tradeoffs with conservation and with other fuels are more critical to the shares. For example, residual fuel oil consumption in the industrial sector in 2010 is higher in the 1990-7% case than in the reference case, because the projected carbon price makes residual fuel less expensive than coal.

Ethanol

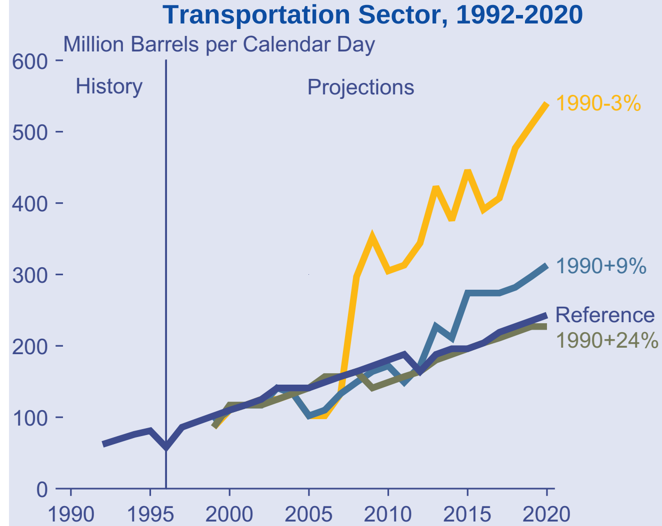
Ethanol consumption is generally expected to be higher in the carbon reduction cases than in the reference case (Figure 101). The United States consumed 80,000 barrels per day of ethanol in 1996 and is expected to consume 180,000 barrels per day in the reference case in 2010. Consumption is generally higher in the carbon reduction cases because of the growth in inexpensive cellulose-derived ethanol and because ethanol is exempt from the addition of a carbon price. However, ethanol consumption trends are quite complex because of changing legislation, production, and tax patterns.

In 1996 almost all ethanol consumed was blended directly into gasoline, but over the forecast period more ethanol is expected to be converted into an intermediate blending component or used in new types of alternative-fueled vehicles. At present ethanol is blended into gasoline as an "oxygenate" for reformulated and high oxygenated gasoline; up to 10 percent ethanol is also blended into traditional gasoline as a petroleum substitute. Oxygenates are used to reduce carbon monoxide emissions, as in oxygenated gasoline, or reduce the precursors of ozone pollution, as in reformulated gasoline. Besides ethanol, the other primary oxygenate is methyl tertiary butyl ether (MTBE). One gallon of ethanol contains approximately twice the amount of oxygen as one gallon of MTBE, but gasoline containing ethanol cannot be transported in pipelines because ethanol has an affinity for water, which limits its use as a blending component. From 1996 to 2010 ethanol for blending is expected to remain at about 80,000 barrels per day in the reference case. In the more stringent carbon reduction cases, ethanol for blending is expected to be significantly higher; in the less stringent cases, it is expected to be slightly lower, because ethanol is more economically attractive when the carbon price is higher.

Similar to the methanol oxygenate MTBE, ETBE (ethyl tertiary butyl ether), an ethanol oxygenate made from a combination of ethanol and isobutylene, is expected to become profitable in the next few years. The advantage of ETBE over straight ethanol is that it can easily be blended with gasoline and shipped by pipeline. In 2010 in the reference case, ethanol for ETBE production is 30,000 barrels per day. In the more stringent carbon reduction cases, ETBE production is expected to be slightly higher; in the less stringent cases, it is expected to be slightly lower, because ethanol is more economically attractive when the carbon price is higher.

To further complicate matters, over the next few years, flexible fuel vehicles are expected to begin burning a significant amount of 85 percent ethanol fuel (E85), as a result of legislative mandates under the Energy Policy

Figure 101. Consumption of Ethanol in the Transportation Sector, 1992-2020



Sources: **History:** Energy Information Administration, *Renewable Energy Annual 1997*, DOE/EIA-0603(97) (Washington, DC, October 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Act of 1992.[74] Around 2005, vehicles capable of burning only ethanol are projected to begin making a significant impact on the ethanol market, because they are expected to have one-third longer range and slightly higher gas mileage than flex-fuel vehicles. From 1996 to 2010, E85 consumption is expected to grow from less than 2,000 barrels per day to about 70,000 barrels per day in all cases, because E85 demand is expected to be driven primarily by legislative mandates. E85 demand is slightly higher in the less stringent carbon reduction cases, because the price of ethanol is attractive; demand is slightly lower in the more stringent carbon reduction cases because overall fuel demand is lower.

The sources of ethanol are also expected to change over time. At present ethanol is primarily derived from fermentation of corn. However, ethanol can also be made from cellulose biomass such as agricultural crop residuals, switchgrass, and other agricultural wood crops. In this analysis cellulose ethanol production was allowed to begin in 2001 at 1,300 barrels per day, based on current construction plans. From 2006 forward, capacity for cellulose-based ethanol is allowed to grow annually at 10,000 barrels per day for the reference case and 16,000 barrels per day for the carbon reduction cases.

Ethanol produced from non-fossil fuels receives a Federal tax credit of 54 cents per gallon. This is equivalent to 5.4 cents per gallon on gasoline blended with 10 percent ethanol. (The credit is prorated for blends of less than 10 percent and applies to the ethanol used to make ETBE.) The tax exemption is scheduled to decline to 51 cents a gallon from 2000 to 2007 and is allowed to remain at 51 cents through the rest of the forecast. Because this tax credit is in nominal dollars, inflation eats away about half its value in real terms by 2020. In the carbon reduction cases, a carbon price is not added to ethanol or the ethanol part of ETBE, because ethanol is produced with a non-fossil-fuel feedstock. Any carbon emitted from burning ethanol is assumed to be recovered when new crops are planted. To prevent ethanol from receiving both a tax credit and an advantage from not suffering an added carbon price, ethanol is allowed to receive the greater of the two; in some cases from 2005 to 2007 the tax credit is greater.

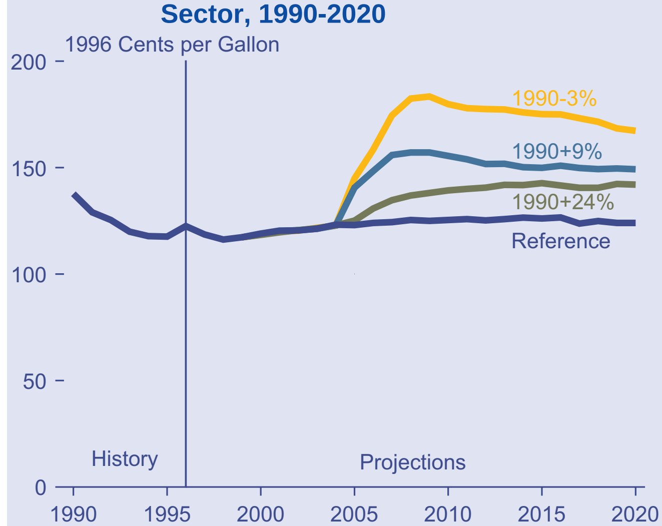
In the carbon reduction cases, ethanol consumption in some years is lower than in the reference case (Figure 101), because the carbon price causes the cost of corn-based ethanol to increase and not enough inexpensive cellulose-based ethanol is yet available. One of the costs of corn production is diesel fuel. When the cost of diesel fuel goes up because of the added carbon price in 2005, the cost of ethanol rises. Higher ethanol prices make MTBE more attractive than ethanol as an oxygenate. In addition, declining oil prices and lower oil demand work to slow increases in the price of MTBE, which is usually made entirely from fossil fuels. Significant quantities of cellulose-based ethanol do not become available until after 2005. Significant new demand for ethanol does not appear until after 2010, when the absence of an added carbon price in ethanol makes ethanol much more attractive as a feedstock for gasoline production. (Appendix A has additional information on the ethanol supply assumptions.)

Petroleum Product Prices

The projected prices of petroleum products in the carbon reduction cases are substantially higher than those in the reference case projections. For example, in 2010 the transportation sector gasoline price is 54 cents a gallon higher in the 1990-3% case than in the reference case (Figure 102). Gasoline prices are higher in cases with higher carbon prices and lower in cases with lower carbon prices, and the prices of other petroleum products follow the same pattern. The primary components of petroleum product prices are the crude oil price, refinery processing, Federal and State taxes, carbon prices, and distribution costs.

In effect, carbon prices cause greater increases in the prices of fuels that have higher carbon contents. In the 1990+24% case, the carbon price in 2010 adds 21 cents per gallon to the price of residual fuel oil but only 9 cents per gallon to the price of liquefied petroleum gas; the corresponding price increases projected for gasoline, jet fuel, and distillate fuel oil are 16, 17, and 19 cents per gallon.

Figure 102. Gasoline Prices in the Transportation Sector, 1990-2020



Sources: **History:** 1990-1995: Energy Information Administration (EIA), *Petroleum Marketing Annual 1995*, web site www.eia.doe.gov/oil-gas/pmal/pmaframe.html (May 30, 1997). 1996: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(96/03-97/04) (Washington, DC, 1996-97). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

[74] Public Law 102-486, Oct. 24, 1996, Title III, Section 303; Title V, Sections 501 and 507.

World oil prices and demand-side effects moderate to some extent the higher prices resulting from the carbon price. Higher product prices lead to reduction in demand in all the carbon reduction cases, which reduces world oil prices. Thus, the world oil price and demand effects combine to relieve some of the pressure on product prices that results from carbon prices (Table 22). The only product with a positive demand-side effect in the carbon reduction cases relative to the reference case is E85 in the 1990-3% and 1990-7% cases (Table 22). Demand for ethanol grows more rapidly in the cases with higher projected carbon prices, because there is no carbon price added to ethanol-based products. (Because ethanol is made from renewable plant material, carbon emitted from burning ethanol is assumed to be recovered when new crops are planted.) In 2010, the projected demand for ethanol is 70 percent higher in the 1990-3% case than in the reference case. With the projected growth of demand for ethanol in the 1990-3% case, increasing supplies of inexpensive biomass-based ethanol are made available, reducing projected price increases in 2010.

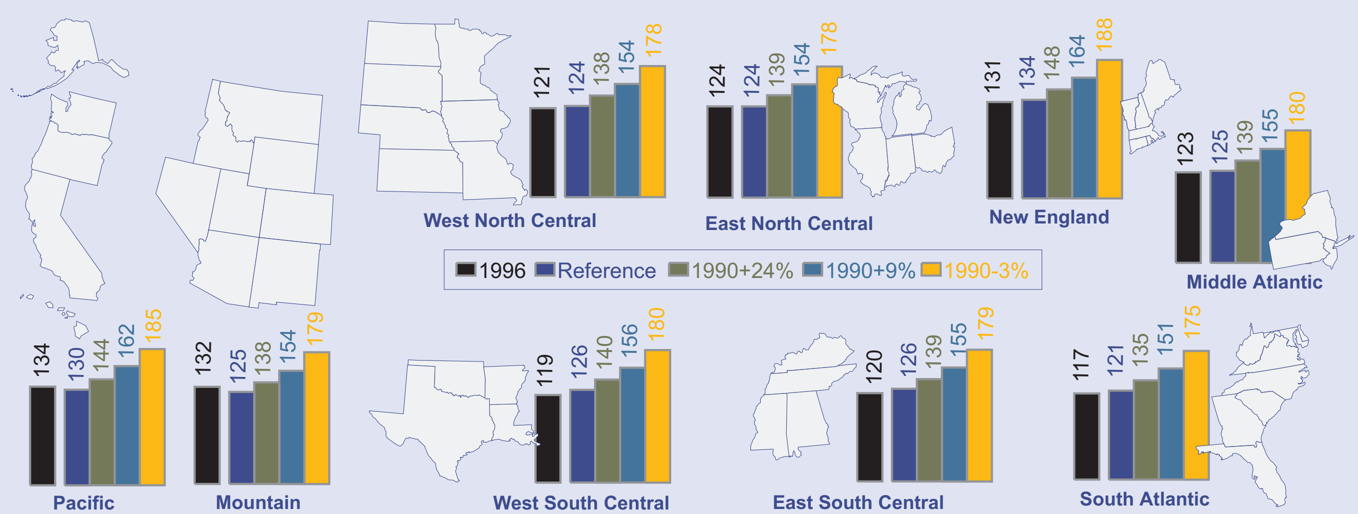
Regional petroleum product prices in the carbon reduction cases reflect many of the same market patterns that exist today. In general, the Northeast and Pacific regions continue to have the highest priced petroleum products in the reference case and the carbon reduction cases (Figure 103). Prices in these regions remain relatively high because State tax rates are higher and supplies are limited. Limited refining capacity in the Northeast region increases reliance on imports and supplies brought in from other regions. In contrast, the Pacific region is isolated from outside sources of supply by geography and by environmental restrictions. Geographically separated from the rest of the Nation by the Rocky Mountains, California must rely heavily on its own refinery production. In addition, the State of California has the most restrictive environmental regulations on gasoline and diesel in the country, which

Table 22. Components of Differential Petroleum Product Prices Relative to the Reference Case, 2010
(1996 Dollars per Gallon)

Fuel	1990+24% Demand Reduction	1990+24% Carbon Price	1990+24% Total	1990+9% Demand Reduction	1990+9% Carbon Price	1990+9% Total	1990-3% Demand Reduction	1990-3% Carbon Price	1990-3% Total
Gasoline	-0.02	0.16	0.14	-0.08	0.38	0.30	-0.15	0.69	0.54
Distillate	-0.04	0.19	0.15	-0.05	0.42	0.37	-0.13	0.81	0.68
Jet Fuel	-0.02	0.17	0.15	-0.07	0.41	0.34	-0.13	0.76	0.63
Residual Fuel	-0.02	0.21	0.19	-0.04	0.50	0.46	-0.08	0.93	0.85
LPG	-0.02	0.09	0.07	-0.08	0.23	0.15	-0.13	0.42	0.29
E85	-0.02	0.03	0.01	-0.08	0.05	-0.03	0.07	0.11	0.18
World Oil Price	-0.02	—	—	-0.05	—	—	-0.07	—	—

Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Figure 103. Retail Gasoline Prices by Region, Average of All Grades, 1996 and 2010
(1996 Cents per Gallon)



Sources: **1996:** Energy Information Administration, Form EIA-782A, "Refiners'/Gas Operators' Monthly Petroleum Product Sales Report," and Form EIA-782B, "Resellers'/Retailers' Monthly Petroleum Product Sales Report," and volume-weighted taxes estimated by the Office of Integrated Analysis and Forecasting. **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

result in additional processing costs and further limit California's sources of supply.

Refinery Industry

Like all energy-intensive U.S. industries, the refinery industry would be adversely affected by policies aimed at reducing the consumption of carbon-based fuels. U.S. refiners would bear the burden of reducing refinery emissions of greenhouse gases, and at the same time demand for their primary products would decline.

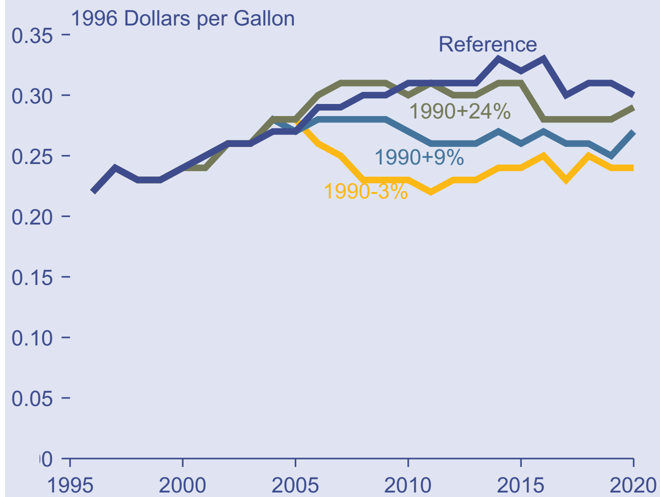
Lower demand for petroleum products is expected to slow the growth of the U.S. refinery industry. In the reference case, the combined distillation capacity of U.S. refineries is projected to be 16.9 million barrels per day in 2010, with a utilization rate of 95 percent. In comparison, in the 1990+24% and 1990-3% cases, the projections for distillation capacity in 2010 are 16.8 and 16.5 million barrels per day, respectively, with utilization rates of 95 and 93 percent. From 2010 to 2020, distillation capacity grows in the carbon reduction cases in response to increasing petroleum consumption. U.S. refiners are not expected to recover all the investments in new capacity made before 2003 in the 1990-3% case, because consumption drops off between 2005 and 2015. Thus, utilization drops off particularly in 2009 in the 1990-3% case. Reduced utilization rates and product consumption may have an adverse impact on smaller or less competitive refineries that cannot develop ways to increase product margins or market share. In the 1990+9% and 1990+24% cases, utilization remains close to 95 percent throughout the forecast, and investment continues to be recovered.

Refinery fuel consumption in the carbon reduction cases drops in direct response to declines in product consumption and crude oil input. Total petroleum consumption at refineries in 2010 is projected to be 143 and 310 trillion Btu lower in the 1990+9% and 1990-3% cases than in the reference case. By 2020, however, compared to the reference case, total petroleum consumption at refineries is higher in the 1990+9% case because residual fuel oil replaces natural gas and is lower in the 1990-3% case because total consumption is lower.

Consumption of natural gas at refineries in the carbon reduction cases drops off after 2010, because gas is projected to be more expensive than petroleum. The higher price for natural gas causes petroleum fuel consumption to rise. Late in the forecast LPG and residual fuel consumed at refineries are higher in the more severe carbon reduction cases than in the reference case, because still gas production and consumption are lower as a result of lower crude inputs to refineries, and because higher natural gas prices result from the higher demand for natural gas. Refinery processing gain also follows the petroleum product consumption and domestic refinery production of products, with processing gains 4 percent and 11 percent lower in the 1990+24% and 1990-3% cases, respectively, than in the reference case in 2010.

Petroleum product margins (wholesale price minus crude costs), which indicate the amount of revenue received by refineries per gallon, are lower in the carbon reduction cases than in the reference case, in response to lower product consumption (Figure 104). In the 1990+24% case, margins for gasoline, distillate, diesel, and jet fuel in 2010 are 4 to 11 percent lower than in the reference case, and in the 1990-3% case they are 26 to 30 percent lower. Between 2010 and 2020 the margins for gasoline, distillate, and diesel remain about the same, and those for jet fuel increase slightly in the carbon reduction cases, because of shifts in demand.

Figure 104. Projected Wholesale Gasoline Margins, 1996-2020



Source: Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Refinery revenues also follow the product consumption and product margins losses. Total projected refinery revenues in the 1990+24% and 1990-3% cases are 5 and 24 percent lower in 2010 than they are in the reference case, and revenues per barrel of product supplied are 3 and 14 percent lower. Total revenue losses associated with the projected drop in world oil prices are 4 percent and 14 percent in the 1990+24% and 1990-3% cases, respectively, in 2010.

The projections of lower product margins, total revenues, and revenues per barrel of product supplied indicate that the U.S. refinery industry could face severe constraints on profits and shareholder returns. Competitive pressures could force petroleum marketers to lower prices while maintaining or improving product quality in order grow market share. U.S. refineries may also face competition from refiners in foreign countries that are not parties to the Kyoto Protocol.

Coal

Background

Coal provides the largest fuel share, nearly 31 percent, of U.S. domestic energy production. Electric utilities and independent power producers generate more than 55 percent of all electricity via coal-fired technology and account for approximately 89 percent of domestic coal consumption. Steam coal is also consumed in the industrial sector to produce process heat, steam, and synthetic gas and to cogenerate electricity, and metallurgical coal is used to make coke for the iron and steel industry. With more than 90 million tons[75] of steam and metallurgical coal shipped in 1996, coal is the only net energy fuel export for the United States. In the reference case, coal production and domestic consumption (expressed in tons) are projected to increase at rates of 1.1 and 0.9 percent per year, respectively, and coal exports are projected to increase somewhat more rapidly at a rate of 1.5 percent annually through 2020, primarily reflecting the continued growth of steam coal consumption for electricity generation in both domestic and overseas markets.

The proposed limitations on carbon emissions will have a significant negative impact on the coal industry. In the carbon reduction cases analyzed here, the advantages of the low carbon content of natural gas and the zero net carbon emissions that are associated with renewables offset the relatively low fuel cost of coal for use in electricity generation. Thus, coal markets are projected to be severely affected, in terms of both overall sales and supply patterns, as the need to reduce carbon emissions results in significant shifts away from coal consumption to natural gas, renewable energy, efficiency improvements in the demand sectors, and—in some cases—nuclear energy (see Chapter 4 for a discussion of fuel switching and changes in electricity generating capacity).

Carbon Emission Considerations

Coal, oil, and natural gas respond differently to restrictions on carbon emissions. Of the three, coal is most affected for reasons that relate to the nature of its markets and its chemical structure. Electricity generation markets, by far the largest market for coal, are increasingly competitive and cost-conscious as restructuring initiatives by States have increasing influence on fuel purchase strategies. Fossil fuels derive their energy content primarily from oxidation of their carbon and hydrogen contents. A fee based on carbon emissions from burning fossil fuels (i.e., a carbon price) naturally falls most heavily on coal, because coal derives a higher percentage of its energy content from the oxidation of carbon than do oil and natural gas.

Coal is heterogeneous in terms of both its energy content and carbon content. Subbituminous coal derives a higher proportion of its energy from carbon than does bituminous coal; thus, production in the large low-sulfur coalfields of the Northern Great Plains (Wyoming and Montana) would be more affected by carbon emissions restrictions than would bituminous coalfields such as those in Colorado and Utah, the Appalachian States, and the Interior region. Lignite, which is produced primarily in Texas, North Dakota, and Louisiana, has more carbon content than subbituminous coal, and its production would be more severely affected than that of bituminous or subbituminous coal in the carbon reduction cases, in the absence of any offsetting factors such as close proximity to customers.

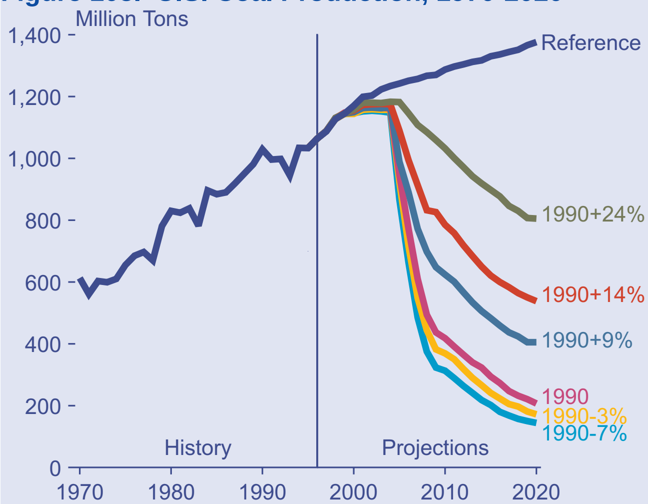
Other factors that would affect the regional impacts of carbon emission restrictions on different coalfields stem from differences in mining and transportation costs. Subbituminous coal production in the southern Powder River Basin of Wyoming had an average mine price of $6.41 per ton in 1996, as compared with bituminous mine prices of $26.68 per ton in Appalachia, $21.43 in the Interior, and $21.61 in the western States. However, there is only a limited market for subbituminous coal in the regions where it is mined. This coal has achieved national importance in the past two decades because of its low sulfur content and mining costs, giving it the ability to bear transportation costs of $20.00 per ton or more while retaining economic competitiveness in markets on the Atlantic, Pacific, Great Lakes, and Gulf coasts, up to 2,000 miles from its origin. A carbon price would create a double penalty for such coal, first by penalizing the coal for its inherent high ratio of carbon to energy content, second by penalizing the carbon content in the transportation fuels that are required to bring it to market. Thus, carbon emissions restrictions would most heavily penalize those coals most dependent on transportation to reach their markets.

Coal Production

In the reference case, U.S. coal production climbs to 1,287 million tons in 2010 and 1,376 million tons in 2020 (Figure 105). In the carbon reduction cases, U.S. coal production begins a slow decline early in the next decade, accelerates rapidly downward through 2010, and then continues to drop slowly through 2020. Coal production in the 1990+24% case is 20 percent lower by 2010, at 1,032 million tons, in the 1990+9% case is 52 percent lower than reference case levels by 2010, at 624 million tons, and 71 percent lower in the 1990-3% case at

[75] In this section, physical quantities of coal are expressed in short tons, a unit of weight equal to 2,000 pounds. Carbon emissions are reported in metric tons, a unit of weight equal to 2,204.6 pounds.

Figure 105. U.S. Coal Production, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

369 million tons. By 2020, coal production in the 1990+24% case is 805 million tons and in the 1990+9% case is 405 million tons, and production in the 1990-3% case drops to a mere 172 million tons.

The projected declines in coal production result primarily from sharp cutbacks in the use of steam coal for electricity generation. Additional declines in production occur from reductions in the use of coal for boiler fuel within the industrial sector, as a result of fuel switching to natural gas. In 2010, coal consumption by electricity generators in the 1990+24% case is 20 percent lower than in the reference case, in the 1990+9% case is 57 percent lower, and in the 1990-3% case it is 79 percent lower. Lower consumption results from a reduction (via retirements) of in-place coal capacity, as well as lower dispatch rates for coal-fired generation because the coal capacity that remains available is used less intensively. In 2010, coal-burning capability in the electricity supply sector drops from 308 gigawatts in the reference case to 300 gigawatts (a 3-percent decline) in the 1990+24% case, 276 gigawatts (a 10-percent decline) in the 1990+9% case, and 266 gigawatts (a 13-percent decline) in the 1990-3% case. Utilization of existing coal capacity drops from 77 percent in the reference case to 65 percent in the 1990+24% case, to 40 percent in the 1990+9% case, and to 22 percent in the 1990-3% case.

In 2020, coal consumption by electricity generators is projected to be 630 million tons in the 1990+24% case, with coal-fired generating capacity at 271 gigawatts and utilization at 55 percent, and only 235 million tons in the 1990+9% case, with coal capacity at 198 gigawatts and utilization at 29 percent. In the 1990-3% case, increased retirements of coal-fired plants result in coal capacity of 100 gigawatts (approximately one-third of reference case levels), coal consumption for electricity generation of 33 million tons, and a very low utilization rate of 9 percent. Operating and maintenance costs per unit of electricity generated will increase for coal plants that are run at low utilization because of thermal fatigue and the inefficiencies of starting and stopping units that were designed for baseload operation.

The expected reductions in coal exports and industrial uses in the carbon reduction cases are somewhat less severe than those in the electricity supply sector, because not all coal-importing countries will be subject to strict carbon caps, and because certain industrial consumers have less flexibility (because of plant configuration or fuel availability) to switch to lower carbon-emitting fuels. As a result, coal production from regions such as Central Appalachia that now serve this set of customers declines somewhat less severely than that from regions such as the Powder River Basin that have the heaviest dependence on electricity producers. Coal export projections are discussed later in this section.

Regional Coal Production Patterns

Reductions in coal consumption are expected to occur in all regions and consuming sectors, but they will be of different magnitudes and affect different coal types. As a result, regional production patterns in the carbon reduction cases will shift differentially across regions relative to the reference case, rather than on a basis that is strictly proportional to national levels of coal consumption. In the electricity generation sector, each reduction in overall coal generation will make it easier to achieve the Clean Air Act Amendments sulfur dioxide (SO_2) target of 9 million tons of SO_2, and in the more severe carbon reduction cases, prices for the SO_2 allowances will be driven to zero. There will be upward pressure on coal transportation rates, as a result of higher prices (from carbon prices) on the diesel fuel used for rail, barge, and truck transportation. At the same time, lower quantities of coal shipments could place downward pressure on transportation rates. The strong shift to greater use of low-sulfur coal, particularly that mined in the West, in the reference case will cease and reverse in consuming regions where local mid- and high-sulfur coal can be delivered at a lower cost than western coal.

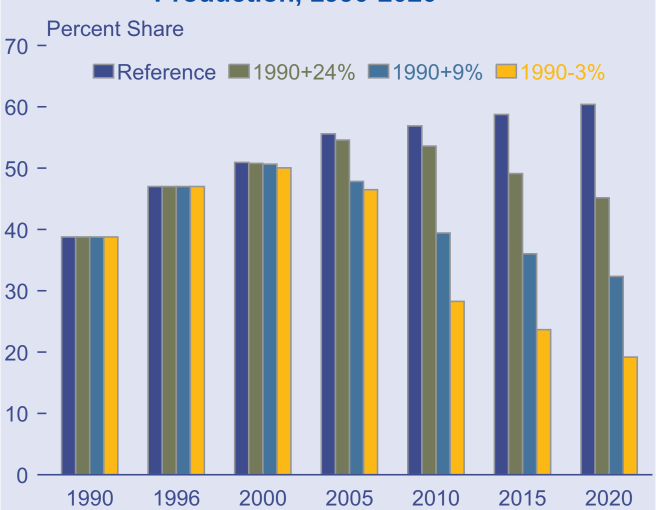
The slower decline in coal consumption in the industrial, metallurgical coal, and export sectors in the carbon reduction cases will translate into relatively less severe production cuts in regions that currently supply these markets than the reductions in those regions that depend more heavily on electricity generators. Nevertheless, there will be intensified intraregional competition to serve these important, albeit declining markets, and some interregional shifts in production occur in the forecast as regional demands shift.

In the reference case, the western share of total U.S. coal production increases from 47 percent in 1996 to 57 percent in 2010, as a result of its lower cost and the growing requirements for low-sulfur coal under the Clean Air Act Amendments (Figure 106). In contrast, the western share in the carbon reduction cases decreases to 54 percent in the 1990+24% case, to 39 percent in the 1990+9% case, and to 28 percent in the 1990-3% case in 2010. Approximately 75 percent of the 179 million ton reduction in western coal production in the 1990+24% case, 486 million ton reduction in the 1990+9% case, and the 628 million ton reduction in the 1990-3% case is borne by subbituminous surface mines in the Powder River Basin. The low-sulfur coal from these surface mines is used almost exclusively for electricity generation and must be transported over relatively long distances to reach many of the markets that are projected to expand in the reference case.

As overall demand falls, eastern minemouth prices are reduced, and there is less economic incentive to transport western coal. Western coal becomes less competitive in electricity generation markets as transportation fuel costs increase, and its potential to expand into most industrial and export applications is limited by its lower heat content and other physical characteristics, such as moisture content and handling problems.

By 2020, western coal production has dropped by an additional 189 million tons from 2010 levels in the 1990+24% case, 115 million tons in the 1990+9% case, and by 71 million tons in the 1990-3% case, with western production shares reaching 45, 32, and 19 percent, respectively. In these cases, the limited coal that is produced in the West is generally sold in markets close to the point of production.

Figure 106. Western Share of U.S. Coal Production, 1990-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD09ABV.D080398B, and FD03BLW.D080398B.

Coal Prices

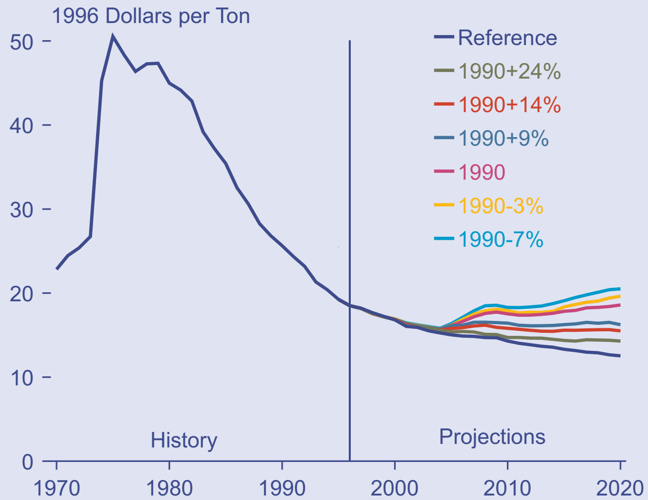
Because coal is heterogeneous in terms of heat content, sulfur level, and other physical properties, trends in national average prices are affected substantially by the relative shares of the various coal types produced and sold and by the units in which prices are reported. For example, coal from the Powder River Basin is generally the lowest-priced coal per ton on a minemouth basis; however, because Powder River Basin coal has roughly two-thirds the heat content of bituminous coal, its cost advantage is somewhat less on a Btu basis and may be nonexistent when delivered to more distant markets.

In general, to the extent that market share shifts away from Powder River Basin coal, which has a low minemouth price, to higher-priced bituminous coal, the national average minemouth price will increase. Similarly, the greater the share represented by metallurgical coal and by premium grades of coal for export use, the higher will be the share-weighted average price. This compositional effect offsets the reduction in minemouth prices at the regional level that is likely to occur because of intraregional competition and the lower production quantities that occur when carbon restrictions take effect. The regional productivity improvements projected in the reference case are assumed to occur at the same rates in all the carbon reduction cases given the same rate of technological progress. However, if the level of investment in new capital equipment is severely constrained, there could be adverse impacts on productivity.

In 2010, real minemouth prices are projected to decrease to $14.29 per ton in the reference case but increase to $14.72 in the 1990+24% case, to $16.42 in the 1990+9% case, and to $17.90 in the 1990-3% case (Figure 107). Minemouth prices in individual regions generally decline in all cases, but the national average minemouth price increases in the carbon reduction cases because of the shift in quantity shares to higher grade and higher priced coal and away from coal with a lower minemouth price, such as that from the Powder River Basin. In some instances, however, even the regional weighted average price for a given coal rank will increase relative to the reference case, if a greater share of coal is being shipped to export or metallurgical markets that demand premium-grade (and therefore higher priced) coals. The pattern of higher national average prices in the carbon reduction cases is accentuated by the projections for 2020, when prices increase from the reference case value of $12.53 to $14.29 in the 1990+24% case, to $16.24 in the 1990+9% case, and to $19.63 in the 1990-3% case.

Delivered prices for coal, as projected in this report, reflect the sum of the minemouth price, transportation cost (in dollars per ton), and the carbon price associated with meeting a carbon reduction target. The carbon price dominates the effects on delivered prices in the

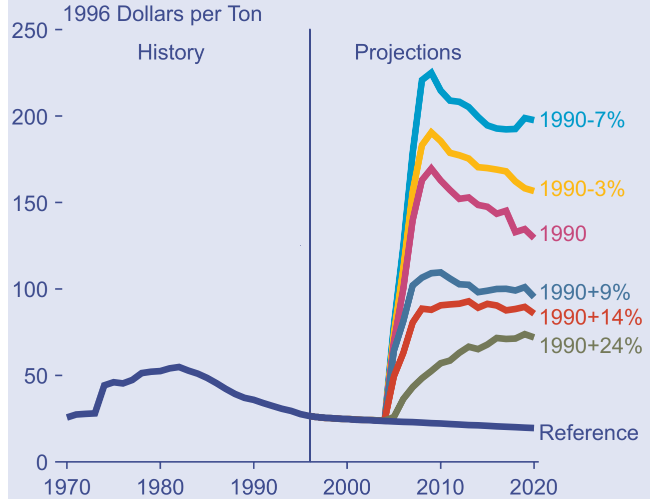
Figure 107. Average U.S. Minemouth Coal Prices, 1970-2020



Note: Carbon prices are added to the delivered price of coal, not to the minemouth price.

Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

Figure 108. Coal Prices to Electricity Generators, 1970-2020



Sources: **History:** Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

carbon reduction cases. In 2010, the carbon fee adds $1.73 per million Btu to the delivered price of coal to electricity generators in the 1990+24% case, $4.18 per million Btu in the 1990+9% case, and $7.51 per million Btu in the 1990-3% case. In 2020, the carbon price component drops to $2.55, $3.62, and $6.14 per million Btu, respectively because the carbon price for all fuels is lower in 2020.

In 2010, the national average delivered price of coal to electricity generators increases from $22.20 per ton in the reference case to $57.03 in the 1990+24% case, $109.56 in the 1990+9% case, and $185.47 in the 1990-3% case (Figure 108). In 2020, the delivered price to electricity generators rises from $19.56 in the reference case, to $71.95 in the 1990+24% case, to $95.33 in the 1990+9% case, and to $156.60 in the 1990-3% case.

Coal Industry Employment and Productivity

Between 1978 and 1996, the number of miners employed in the U.S. coal industry fell by 5.8 percent a year, declining from 246,000 to 83,000. The decrease primarily reflected strong growth in labor productivity, which increased at an annual rate of 6.7 percent over the same period. An additional factor was 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. The Powder River Basin share of total U.S. coal production increased from 13 percent in 1978 to 30 percent in 1996.

In the reference case, productivity improvements are assumed to continue but to decline in magnitude over the forecast period. On a national basis, labor productivity increases at an average rate of 2.3 percent a year over the whole forecast. The annual rate of increase slows, however, from 5.8 percent in 1996 to approximately 1.6 percent per year from 2010 to 2020. With improvements continuing over the forecast period, further declines in employment of 1.3 and 1.1 percent per year are projected from 1996 through 2010 and from 2010 through 2020, respectively. In absolute terms, coal mine employment declines from 83,000 in 1996 to 69,000 in 2010 and to 62,000 in 2020.

Regionally, labor productivity in the carbon reduction cases is assumed to improve at the same rates as in the reference case.[76] As a result, lower levels of production in the carbon reduction cases in all supply regions, relative to the reference case, result in lower employment levels in all regions. Table 23 shows projections of coal mining jobs in 2010 by region for the reference case and the carbon reduction cases. In the 1990+24% case, coal mine employment declines at a rate of 2.5 percent a year between 1996 and 2010, falling from 83,000 in 1996 to 58,000 in 2010 (Figure 109). In the 1990+9% case, employment declines at a more rapid rate of 4.6 percent a year to 2010, resulting in employment of only 43,000 miners in 2010. In the 1990-3% case, coal mine employment declines at a rate of 7.2 percent a year between 1996 and 2010, reaching 29,000 in 2010.

Production and employment are positively correlated. In 2010, the projected levels of coal production in the

[76] Higher or lower rates of productivity growth could occur in the carbon reduction cases depending on the skill level and motivation of the labor force in a rapidly contracting job market and the rate at which new capital equipment and technology are adopted.

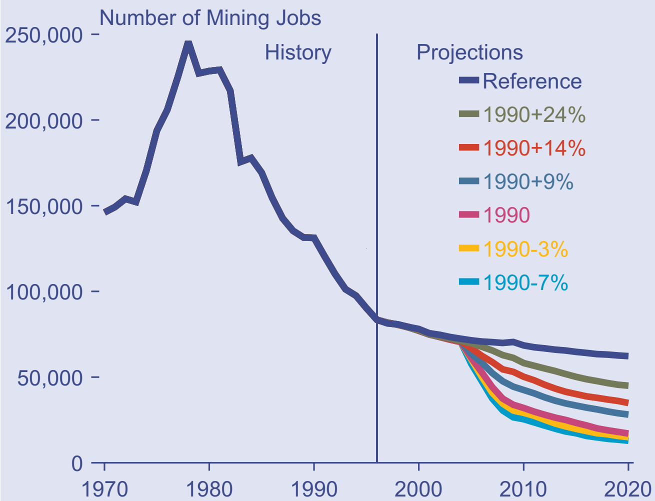
Table 23. Projected Number of Coal Mining Jobs by Region, 2010

Region	1996	Reference	1990+24%	1990+14%	1990+9%	1990	1990-3%	1990-7%
Appalachia[a]	60,001	49,477	41,617	37,340	32,386	26,034	24,307	21,654
Interior[b]	13,477	8,043	7,801	7,617	6,257	4,315	3,484	2,663
Powder River Basin[c]	4,159	5,013	3,827	2,490	1,829	1,015	844	673
Other West[d]	5,825	5,693	4,785	2,859	2,254	1,034	941	895
U.S. Total	**83,462**	**68,519**	**58,223**	**50,224**	**42,531**	**32,053**	**29,187**	**25,486**

[a]PA, OH, MD, WV, VA, and KY (east).
[b]IL, IN, KY (west), IA, MO, KS, AR, OK, TX, and LA.
[c]WY, MT, and ND.
[d]CO, UT, NM, AZ, AK, and WA.

Source: **History:** Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-584(96) (Washington, DC, November 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, FD07BLW.D080398B.

Figure 109. Coal Mine Employment, 1970-2020



Sources: **History:** 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 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997). **Projections:** Office of Integrated Analysis and Forecasting, National Energy Modeling System runs KYBASE.D080398A, FD24ABV.D080398B, FD1998.D080398B, FD09ABV.D080398B, FD1990.D080398B, FD03BLW.D080398B, and FD07BLW.D080398B.

1990+24% and 1990-3% cases are 20 percent and 75 percent lower, respectively, than in the reference case. In comparison, employment in the 1990+24% case is only 15 percent lower in 2010 than in the reference case and employment in the 1990-3% case in 2010 is only 57 percent below the reference case. The projected declines in employment are smaller than the declines in production because of the relatively greater losses in output projected from mines in the Northern Great Plains, which require less labor per unit of output than mines in other coal-producing regions.

Table 24 provides an indication of the importance of coal industry jobs in the top coal-producing States. The table shows that the wages associated with coal mining exceeded 2 percent of all wages paid in 1996 in West Virginia, Kentucky, and Wyoming. In West Virginia and Wyoming, they accounted for more than 5 percent of all wages paid. The fact that coal mining wages are higher than average wages in these States is shown by the fact that coal industry jobs account for a greater share of total wages than their share of total employment. In West Virginia, the coal industry employs 3.2 percent of all workers in the State but accounts for 6.5 percent of all wages paid. In Wyoming, coal industry workers account for only 2.2 percent of all jobs but earn 5.3 percent of all wages. Similarly, in Kentucky, the coal industry provides 1.2 percent of all jobs but 2.1 percent of all wages. Table 24 also shows that while the potential for direct losses of coal-related wages and employment is concentrated in the 10 States listed, it is much more strongly concentrated in West Virginia, Kentucky, Wyoming, and perhaps Pennsylvania (depending on whether the absolute amount of wages and employment at stake is counted, or the relative proportion of the State's total wages and employment).

In addition to the substantial contraction of the U.S. coal industry projected in the carbon reduction cases, the U.S. rail industry, which derives considerable revenues from coal shipments, also stands to be greatly affected (see box).

U.S. Coal Exports

U.S. coal producers exported 90 million tons of coal in 1996. Of that amount, 59 percent represented shipments of coking coal for use at integrated steel plants worldwide, and 41 percent was steam coal, used primarily for electricity generation and for the production of process steam and direct heat for industrial applications. In 1997, U.S. coal exports fell by 7 million tons, reversing the upward trend of the previous 2 years. The decline was mostly in steam coal exports, as a result of weak international coal prices and strong competition from other coal-exporting countries.

In the reference case, U.S. coal exports are projected to increase from 90 million tons in 1996 to 113 million tons in 2010. All the increase reflects expected growth in steam coal exports, with exports of metallurgical coal projected to decline slightly. In the reference case, world metallurgical coal trade remains relatively constant, although regionally there is a slight shift away from markets in Europe and Japan to Brazil and the

Table 24. Coal Industry Wages and Employment, 1996

State	Wages		Employment[a]	
	Million 1996 Dollars	Percent of State Total	Number of Jobs	Percent of State Total
West Virginia	1,041	6.53	21,033	3.17
Kentucky	815	2.06	19,372	1.20
Wyoming	258	5.29	4,706	2.20
Pennsylvania	512	0.34	11,214	0.22
Illinois	347	0.20	6,136	0.11
Virginia	290	0.03	7,039	0.02
Alabama	332	0.74	6,552	0.04
Ohio	172	0.12	3,889	0.01
Texas	149	0.65	2,861	<0.01
Montana	49	0.66	933	0.03
Subtotal	3,965	0.42	83,375	0.03
United States	**4,691**	**0.17**	**97,649**	**0.08**

[a]Relative to Form EIA-7A, "Coal Production Report," which focuses on workers directly involved in the production and preparation of coal, the data presented in this table include coverage of corporate officials, executives, clerical workers, and other office workers. Data from Form EIA-7A indicate that 83,462 miners were employed in the U.S. coal industry in 1996.

Source: U.S. Department of Labor, Bureau of Labor Statistics, ES-202 Program, "Covered Employment and Wages."

developing countries in Asia. World steam coal trade is projected to increase by 45 percent between 1996 and 2010, rising from 305 million tons to 441 million tons. The U.S. share of total world coal trade is projected to remain constant at about 18 percent.

In the reference case, Japan's remaining two coal mines are assumed to be closed shortly after 2000. Currently these mines have a combined annual production capacity of about 3.5 million tons, representing less than 3 percent of Japan's total coal consumption. In 1996, coal consumption in Japan amounted to 144 million tons—82 million tons of steam coal (including 9.5 million tons of coal for pulverized coal injection at blast furnaces) and 62 million tons of coking coal.

In the carbon reduction cases, two alternative coal trade scenarios were developed. In a severe carbon reduction case (1990-3%), carbon emissions in Western Europe were assumed to be 8 percent below their 1990 level by 2010 consistent with the limits for the European Union that were specified in the Kyoto Protocol. Similarly, carbon emissions in Japan were assumed to be 6 percent below their 1990 level by 2010. Coal was assumed to play a proportionately greater role than oil or natural gas in meeting these emission reductions, because it has a higher carbon content (on a Btu basis) and the opportunities to substitute for petroleum products in the transportation sector are limited. In Western Europe, both domestic coal production and imports were assumed to decline by approximately 50 percent, but in Japan coal imports had to account for the total reduction in coal consumption.

In Europe, steam coal imports from all sources are reduced from 156 million tons in the reference case in 2010 to 47 million tons in the 1990-3% case. Only steam coal imports to the industrialized Annex I countries in Europe are reduced. Steam coal imports to Japan, the only Annex I country in Asia, are reduced from 99 million tons in the reference case in 2010 to 56 million tons in the 1990-3% case. Because other fuels are not easily substituted for coal coke at steel plants, coking coal imports are not adjusted downward.

Steam coal imports to Japan are reduced by a relatively smaller amount than are imports to Europe, primarily because Japan has limited access to alternative sources of energy such as natural gas and renewable fuels. In addition to reduced use of coal, other strategies that Japan may pursue to meet its carbon reduction targets include purchasing surplus emission allowances from other signatory countries and pursuing an accelerated nuclear program.[77]

U.S. coal exports to Europe and Asia in 2010 are projected to be lower by 27 and 7 million tons, respectively, in the 1990-3% case (and all other carbon reduction cases where U.S. carbon emissions are held at or below the 1990 level in 2010) than in the reference case. In these cases, U.S. coal exports are projected to decline to 76 million tons in 2010.

In the moderate cases, 1990+24% and 1990+9%, developed to evaluate the potential impacts of less severe reductions in carbon emissions, Western European coal consumption and imports were assumed to decline by a smaller amount than in the severe case discussed above,

[77]In June 1998, a panel headed by then Prime Minister Ryutaro Hashimoto urged the government to construct an additional 20 new nuclear plants over the next 12 years, with the goal of increasing Japan's nuclear generation by more than 50 percent between 1997 and 2010. EIA's *International Energy Outlook* (*IEO98*) high nuclear case projects an increase of 12.4 gigawatts (29 percent) in Japan's nuclear generating capacity over the same period. The *IEO98* reference case projects an increase of only 5.2 gigawatts (12 percent) between 1996 and 2010.

reflecting the lower emission target. Japanese coal consumption and imports were also assumed to decline by a smaller amount as in the severe case. In Europe, projected steam coal imports from all sources are reduced from 156 million tons in the reference case in 2010 to 96 million tons in the 1990+9% case. Only steam coal imports to the industrialized Annex I countries in Europe are reduced.

U.S. coal exports to Europe and Asia in 2010 are projected to be lower by 17 and 4 million tons, respectively, in the 1990+24% and 1990+9% cases (and in all other carbon reduction cases where U.S. carbon emissions are above the 1990 level in 2010) than in the reference case. In these cases, U.S. coal exports of 89 million tons are projected for 2010, as compared with 113 million tons in the reference case.

Impacts on the Rail Industry

In 1996, 705 million of the 1,064 million tons of coal produced in the United States (66 percent) was transported to consumers partly or entirely by rail. Coal freight provided Class I railroads with $7.7 billion, 23 percent of all 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 39 percent of all car loadings during 1996.[a] Available data from the Federal Railroad Administration that summarize railroads' reported return on investment and the extent of their dependence on coal freight revenues are shown in the table below.

Because the carbon reduction cases analyzed here project heavier losses in coal production for western than for eastern coalfields, and because much of the production from western coalfields is shipped long distances into 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.

Progressively deregulated since the Staggers Rail Act of 1986, 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). The recent merger between Union Pacific and Southern Pacific was followed by a period of service problems (particularly in Texas, but also affecting rail shipments throughout the Union Pacific - Southern Pacific system) that have not yet been entirely resolved. As a result of these service issues, there has been controversy surrounding the policies of the Surface Transportation Board as it has sought to balance the needs of railroad shippers and

Revenue Adequacy and Relative Dependence on Coal Revenue by Railroad, 1989-1995

Railroad	1989		1991		1993		1995	
	Percent of Total Revenue From Coal	Rate of Return on Investment	Percent of Total Revenue From Coal	Rate of Return on Investment	Percent of Total Revenue From Coal	Rate of Return on Investment	Percent of Total Revenue From Coal	Rate of Return on Investment
Eastern District								
Conrail	15.4	2.6	16.8	NM	14.2	6.5	15.9	6.8
CSX	34.4	6.1	35.3	NM	29.9	0.1	29.8	6.5
Florida East Coast	1.1	10.3	1.0	2.2	NA	NA	NA	NA
Grand Trunk Western	8.1	1.9	9.4	NM	8.2	NM	7.9	NM
Illinois Central	16.0	11.2	15.2	15.2	12.7	14.7	13.9	17.2
Norfolk Southern	36.1	11.9	37.0	6.0	32.9	12.1	30.9	12.1
Western District								
Atchison Topeka & Santa Fe	7.7	NM	8.9	6.5	8.7	1.9	7.3	5.3
Burlington Northern	33.0	12.5	33.5	NM	31.9	9.4	32.7	6.3
Chicago & Northwestern	12.4	8.2	14.1	7.1	13.5	10.3	15.5	NA
Kansas City Southern	33.7	10.7	31.9	9.3	29.9	9.0	19.7	7.9
Soo Line	11.3	NM	12.8	4.0	9.2	NM	3.8	NM
Southern Pacific	2.2	1.8	2.4	NM	3.2	3.5	9.4	1.3
St. Louis Southwestern	2.6	1.8	2.2	NM	3.2	3.5	9.4	1.3
Union Pacific	16.1	10.4	17.5	1.7	16.8	11.1	19.0	11.7

NM = negative returns on investment are described only as "not meaningful" in the source.
NA = not available, usually because the railroad has ceased to operate as an independent entity.
Source: Federal Railroad Administration.

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Impacts on the Rail Industry (Continued)

the continued profitability of the Union Pacific, and of the Nation's major railroads in general. Even if these issues are successfully resolved over the next few years, the adoption of carbon emissions restrictions would inevitably result in a reduction in domestic coal traffic handled by the railroads.

As suggested by the results of the carbon reduction cases, the reductions in coal traffic range from moderate to severe, depending on the case. In all cases, western coal, particularly subbituminous coal from the Powder River Basin, would 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 and its high ratio of carbon to energy content. As shown in the table, the Burlington Northern and Union Pacific systems have a fairly high dependence on coal freight revenue; therefore, the loss of revenue associated with carbon reduction measures could create significant financial problems for those firms. Lignite production in Texas, Louisiana, and North Dakota would also be severely reduced by carbon emissions restrictions, but the effect on rail revenues would 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 carbon reduction cases are proportionately and absolutely less for Appalachian coalfields 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 carbon reduction cases, Appalachian coal production could be reduced by one-third to one-half, with potentially serious financial consequences for these carriers.

[a] Association of American Railroads, Freight Commodity Statistics.