CHAPTER 5

Markets and Projected Demand for Federal Coal

Contents

List of Tables

List of Figures

CHAPTER 5

Markets and Projected Demand for Federal Coal

The concentration of Federal coal resources in the West means that the demand for Federal coal is closely tied to the demand for Western coal. The demand for Western coal is determined by the dynamic interaction of various economic and institutional factors that affect: I) coal use in the far West, 2) the competitive position of Western coal in energy demand centers in the Midwest, North-Central and South-Central United States with respect to other coal provinces (the Gulf Coast and Interior provinces primarily), and 3) the competitive position of Western coal with respect to competing fuels such as oil, gas, and uranium.

This chapter first examines in a general way the factors that affect the overall demand for coal, and then looks a little more closely at the effect these factors have on the market situation for Western coal as of 1980. The impact that likely or possible trends could have on Western markets through to 1990 are then examined in some detail. Next, the major market advantages and disadvantages of coal produced from the six major Federal coal-producing States (North Dakota, Montana, Wyoming, Colorado, Utah, and New Mexico)* are summarized with an analysis of the relative competitive position of coal production from these States in different regions of the country. Finally, the results of recent market studies and forecasts of the demand for Western coal in the period 1980 to 1990 are analyzed in relation to demand estimates that were developed by OTA to evaluate potential production from existing Federal coal leases. The chapter concludes with a general look at the range of possibilities for demand for Western coal in the context of total U. S. coal demand between 1980 and 2000.

*Arizona produced almost as much coal in 1979 as New Mexico, and thus ranks as a major Western coal-producing State. However, all production in Arizona is from Indian land and is thus not considered in this chapter.

Factors Affecting the Demand for Coal

The demand for coal is primarily the result of individual consumers or users making choices based on suitable quality and the price of coal from different regions and, when other fuels can be substituted for coal, the price of alternative noncoal energy resources. Although these relative prices may be significantly affected by "nonmarket" factors, such as Government policy, in this chapter the term "market demand" refers to least-cost energy purchasing decisions made by users,** "Nonmarket" factors in the form of Government policy can have a significant impact on the demand for coal, but a distinction can be made between Government policies that: 1) change the institutional context of the market system and 2) directly stimulate the demand for coal. Policies in the first category include most environmental regulations that change the relative cost of using coal from different regions. The market system itself makes the necessary adjustments to the new institutional context. Thus, the mar-

** It should be noted that coal quality factors affect purchasing decisions and may result in the purchase of higher cost coal. For example, higher delivered cost of Western low-sulfur coal East of the Mississippi compared to local high-sulfur coal has been accepted by some utilities because retrofitting old plants with stack gas scrubbers was considered too costly and risky due to uncertainties surrounding the reliability of available scrubbers. However, even in this case the decision to purchase more expensive coal is based on the belief that in the long run the cost of generating electricity would be cheaper than the use of less expensive high-sulfur coal.

ket demand for coal changes, but shifts in the level of demand and regional shifts in coal production are based on least-cost energy purchasing decisions. Government policies that directly stimulate demand for coal include Government subsidies for a commercial coal-based synthetic fuels industry and the off-gas requirements of the Powerplant and Industrial Fuel Use Act. * At the present time Government intervention in the market system to directly increase demand for coal forms a small percentage of coal use in the United States. However, if Government subsidies are seen as necessary to develop a large-scale coal-based synthetic fuels industry, this situation could change.

Table 26 lists some of the major factors that affect demand for coal. These factors fall into three broad categories: 1) user needs, 2) costs (mine mouth, delivered, and costs of converting into useful energy), and 3) institutional constraints on production.

User Needs

User needs are the primary determinant in the demand for coal. High levels in the electrical growth rate, high steel production, and extensive conversion of industrial and electric utility boilers to coal from oil and gas will all mean an increase in coal demand. High levels of coal-based synthetic fuels development and high overseas demand for coal will also increase coal markets. The important role that coal is expected to play in the U.S. energy picture is largely the result of the high cost and less certain availability of oil. Coal's main competitors as substitutes for oil and gas are nuclear power and energy conservation. ** Low levels of energy conservation and nuclear power growth would contribute to increased demand for coal.

Coal markets are also affected by the extent of substitutability of alternative sources to meet user needs. Electric utility needs can be met by oil, gas, uranium, conservation* and a wide range of coal qualities. For a new powerplant the primary determinant in utility choice of fuels is the relative cost of producing electricity. Once a choice has been made and a powerplant built to meet the specifications of the chosen fuel some substitutions become impossible (i.e., nuclear to coal) and most become costly (i.e., oil or gas to coal and shifts from one coal type to another). On the other hand, there is little substitutability in the demand for metallurgical-grade coal.**

Cost Factors

For a coal producer to sell his coal, he must usually produce it at a price such that delivered cost per Btu to the consumers (mine plus transportation cost) is lower than the delivered cost per Btu of coal offered by competing coal producers. If the offered price is higher, then the coal must be more attractive to the prospective buyer, either because the coal quality characteristics are more suitable for his need, or for some other reason such as lower costs to produce electricity or greater assurance of reliable delivery.*** Basic mine

*The off-gas requirements in this act actually have elements of both kinds of policies: the law requires conversion from gas to coal even if it is cheaper for the utility to continue with gas (i.e., least cost energy purchasing decisions are not allowed), but on the other hand, once the shift is made to coal, the open market will determine where the utility buys its coal based on a narrower set of least cost considerations. These requirements have now been repealed by Congress (see third footnote, next column),

**If conservation reduces the total level of energy consump tion which is served by oil and gas, there is less need to substitute other energy sources. Without conservation the demand for coal as a substitute to oil and gas would be higher, and it is in this specific sense that conservation is a competitor to coal.

*Conservation in this context refers to utility investments in activities that reduce total demand or reduce peak demand (such as time-of-day pricing, load management, insulation loan programs) because they are cheaper than investments that increase generating capacity. This kind of conservation is different from conservation by electricity users that is purely in response to increased cost of electricity. The latter form of conservation reduces the amount of electricy a utility needs to produce, but does not fulfill the needs of the utility as a business.

**To a limited extent low-sulfur, low-ash coals that do not have normal coking properties can be blended with metallurgical-grade coal to produce coke, Newly developing technology for production of "form coke" can take a wide range in rank of coal, although sulfur and ash content are still important.

***The Powerplant and Industrial Fuel Use Act which mandated conversions to coal from gas in utility and large industrial boilers may result in the choice of coal as a fuel where cost comparisons would indicate staying with gas. However, the impact of this law has been reduced by the Omnibus Budget Reconciliation Act passed by Congress in August 1981 which repealed the ban on use of natural gas in 1990 in section 301 of PIFUA, Instead, utilities that use natural gas as a primary fuel are required to develop conservation plans to reduce current annual power production attributable to natural gas by 10 percent within 5 years.

Table 26.—Factors Affecting Market Demand for Western Coal

Factor	Markets increase when factor is:	Markets decrease when factor is:	Current market situation in West	Current or probable trends (1980-90)
User needs				
Utilities				
Electrical growth rate	High (>5%)	Low (<3%)	Low	Low - moderate
SO_2 emissions standards	1970 NSPS, limits on total emissions	1979 NSPS or no emissions limits	Current standards reduce demand compared to 1970 NSPS.	Amendments to Clean Air Act could change situation either way.
Competing energy sources				
Cost of oil & gas	High	Low	High	Higher
Nuclear power growth	Low	High	Low (in West)	Low (in Western coal's market area)
Industrial				
Steel production	High	Low	Low	Low
Industrial boiler conversions	High	Low	Low	Low - moderate
Synthetic fuels development	High	Low	Low	Low - moderate
Foreign export	High	Low	Low	Possible increase
Costs[a]				
Mine (FOB) cost per million Btu			Overall:[b] low (Northern Plains) moderate (Rockies)	Little change
Equipment cost, operation & maintenance	Low	High	Moderate	Little change
Labor	Low	High	Low - moderate	Little change
Reclamation	Low	High	Low	Little change[c]
Health & safety	Low	High	Low - surface mines High - underground mines	Little change Little change
Royalty rates	Low	High	Low - existing leases High - new leases	Increases as existing leases come up for adjustment
Severance taxes	Low	High	Low - high	Some increase or decrease at State level is possible
Delivered cost				
Transportation	Low	High	Low (mine-mouth plants) High (export)	Additional increases likely with rail deregulation and increased fuel costs. Possible decreases in some localities with slurry pipelines
Technologies for clean burning of coal (cost)	High[d]	Low	Moderate - high	Decreases possible through increased experience and technological improvements
Institutional constraints at mine	Low	High	Institutional constraints are highly site specific. See chs. 8 and 10 for specific examples.	

[a]For utilities and industrial boiler users the essential cost factors are delivered price and the cost of technologies for clean burning of coal. For the steel industry cost comparisons are restricted to coals that have characteristics that are suitable for making coke.
[b]Relative to the cost of Midwestern coal.
[c]Little change in reclamation costs is likely in the West, but proposed amendments to the Surface Mining Control and Reclamation Act that would give States more flexibility in setting reclamation standards could decrease markets for Western coal because the relatively high reclamation costs in the Midwest resulting from enforcement of the act might be reduced.
[d]High costs for technologies promoting clean burning of coal (coal cleaning, flue gas desulfurization and fluidized bed combustion) favor Western coal because of its generally low sulfur and ash content. Decreases in costs favor increased use of high sulfur Midwestern coal. Reliability of these technologies is also an important factor, with low reliability favoring Western coal and high reliability favoring Midwestern coal.

SOURCE: Office of Technology Assessment

costs include the cost of equipment purchase, operation and maintenance, labor, and the cost of reclamation and improving health and safety conditions for miners. Additional costs may be added as a result of royalties that must be paid to the owner of the coal and severance taxes imposed by States in which the coal is mined. Low costs in all these factors relative to other coal producers improves the competitive position of a coal deposit. Heat content can make an important difference in the unit-energy cost of coal. At any given price, all other things being equal, coal with a higher heat content is cheaper to use for a given job than coal with a low heat content.

Coal is a commodity with a low specific value compared to other commodities, often costing less than a cent per pound at the mine and sometimes considerably less. Consequently transportation costs represent a substantial portion of the delivered cost of coal if the user is a significant distance from the mine. Low transportation costs relative to other coal producers increase marketing potential. Transportation costs can bean important limiting factor where coalfields are distant from existing networks that transport coal. For example, the high cost of building a coal transportation infrastructure to connect the coalfields in southwest Utah with existing networks is an impediment to developing this area.

Institutional Constraints

In some situations a coal reserve may be available for development at a cost that is competitive with coal from other sources, but the coal cannot be mined because of environmental reasons, labor or equipment shortages, or possibly limited or nonexistent transportation capacity. An example of an environmental threshold that might eventually delay or possibly limit expansion of coal development appears to exist in North Dakota. All currently proposed mines in North Dakota are associated with proposed nearby power and synthetic fuel plants. Operation of all currently permitted plants may exceed the "prevention of significant deterioration" air quality increments for sulfur dioxide ($S0_2$). If this is the case, the level of mine development may be limited as well. (Additional discussion of this situation can be found in ch. 10.) Labor shortages and limits to transportation capacity are usually relatively short-term conditions that can be corrected in the presence of strong demand for coal from a region. Specific transportation and environmental issues affecting Western coal development are discussed in more detail in chapters 8 and 10, respectively.

Institutional constraints are more significant in their impact on production at a specific locality than on the demand for coal in general, Unless institutional constraints limit production in a large number of coal-producing regions, demand is met by increased production from regions that do not experience constraints. Such shifts in production may result in some cost increases, but unless production is constrained in a number of regions, causing rapid increases in production of marginal coal reserves that cost more to mine than existing mines, such cost increases are not likely to be large. ' If reasonable environmental and socioeconomic thresholds set limits on coal production in an area, cost increases resulting in shifts in coal production to other areas can be considered part of internalizing the environmental and social costs of mining coal. *

[1]The cost impact of such regional shifts in production depends on both changes in mine mouth cost and transportation cost. ICF has noted that moderate shortfalls in some regions can be compensated for by increased production from nearby regions which are less constrained and which have adequate reserves of comparable coals available, but that if constraints are widespread, the net costs to society can be high (ICF, Inc., Analysis and Critique of the Department of Energy's August 7, 1980 Report Entitled "Preliminary Nationcd and Regional Coal Production Goals *for* **1985, 1990 and 1995,** Washington, D. C.: ICF, Inc., October 1980).

*However, it must be recognized that there may be considerable disagreement as to what constitutes a "reasonable" environmental or socioeconomic threshold at a specific location.

Trends in Factors Affecting the Demand for Western Coal: 1980-90

The last two columns in table 26 give a general view of the current market situation in the West with respect to the factors affecting the demand for coal and identify likely or possible trends in these factors in the period from 1980 to 1990. The following text discusses only the most salient factors listed on this table with respect to Western coal.

Electrical Growth Rate

Electric utilities are by far the most significant user that will be affecting the demand for Western coal. In 1979 utilities purchased 70 to 96 percent of the coal produced in the major Western Federal coal-producing States (see table 22, ch. 4). The electrical growth rate will probably be the single most important factor affecting demand for coal from Western States during the next 10 years. The electrical growth rate in the last few years has declined significantly compared to rates following World War II. The average growth rate of total net generation of electricity from 1945 to 1973 was 7 percent. Average annual growth since 1973 has slowed substantially and has averaged less than 2 percent during the last few years (total U.S. consumption of electricity in 1979 was 1.9 percent higher than in 1978 and in 1980 the increase was 1.4 percent).

The decrease in the electrical growth rate has been largely the result of conservation in response to increasing costs of electricity, although the economic situation of the past few years has been an important factor in recent very low growth rates. This decline in the electrical growth rate is a major reason for the decreases in projections for demand for Western coal over the last few years. For example, the Department of Energy's (DOE) 1990 production goals for the western Northern Great Plains (which also includes southern Wyoming) dropped from 529 million tons in the 1978 forecast to 336 million tons in the 1980 preliminary forecast. Most of this drop can be attributed to a reduction in the electrical growth rate used in the forecast.

Efforts to project longer-term electricity growth rates have historically not been very accurate, but table 27, which compares projected growth rates over the last decade, show there has been a consistent downward trend in projected growth for similar time periods in the future. Table 27 shows that recent electrical growth projections for the period from 1979 to 1985 range from 2,5 to 4.1 percent. The low projections are higher than growth rates in the past few years, reflecting a belief that an economic upturn will increase demand for electricity. The upper range of 4. I percent projected by the National Electric Reliability Council (NERC) in July 1980 is considered by a number of observers to be somewhat high. The National Coal Association (NCA), for example, uses the NERC electrical growth rate for their high projection and an electrical growth rate of 3.5 percent for their most likely projection of U.S. coal production.' Also the electrical

Table 27.—Comparison of Historical Forecasts of Annual Growth Rate of Total Electric Generation

Scurce and year of study	Projected growth rate (percent)	Time period
U.S. Energy Outlook–1971	7.2	1971-85
Department of the interior—1972	6.1	1971-2000
Oak Ridge National Laboratory–1973	4.4	1974-85
Lawrence Livermore Laboratory— 1974	5.6	1974-85
Technical Advisory Committee—1974.	6.0	1974-85
Oak Ridge National Laboratory—1975	5.1	1974-85
Westinghouse—1975.	5.0	1974-85
Electrical World—1975	5.8	1975-85
Exxon Co.—1977	4.8	1977-90
EIA's Annual Report to Congress—1978 ......, ...	4.7	1977-85
CONAES–1978 . . . .,	0.7-3.2	1975-2010
National Electric Reliability Council — July 1980, . .	4.1	1979-89
National Electric Reliability Council — July 1981	3.7	1981-90
Department of Energy—August 1980. .	3.0	1978-85
ICF, Inc.—November 1980, .,	3.5	1979-85
ICF, Inc.—November 1980, ...	3.0	1985-90
Economic Regulatory Administration and Energy Information Administration—December 1980 . . .	2,5	1979-85
1980 actual[a] . . . ., ...	1,4	1980

[a]Rate of increase experienced for the first 47 weeks of 1980 over corresponding period of 1979.

SOURCES: Forecasts from 1971 to 1978 from table 39, U S Department of Energy, Short *Term Energy Outlook,* DOE/EIA-0202/2 (Washington, DC U.S. Government Printing Office, February 1980) Projections of the Demand and Conservation Panel of the Committee on Nuclear and Alternative Energy Systems as scenario B cited in Science, Apr. 14, 1978, p. 151

National Electric Reliablilty Council, 1980 Summary of *Protected Peak Demand, Generating Capability and Fossil Fuel Require. ments for the Regional Reliability Councils of NERC* (Princeton, N. J.: NERC, July 1980), Calculated from table 9 It should be noted that this is a drop from the 4 4-percent rate projected by the Regional Councils in their April 1980 reports to the U S. Economic Regulatory Administration,

National Electric Reliability Council, *Electric Power Supply and Demand 1981-1990* (Princeton, N.J.: NERC, July 1981)

Department of Energy, *Preliminary National and Regional Coal Production Goals for 1985, 1990 and 1995* (Washington, D C DOE, Aug 7, 1980), From table 19

ICF, Inc., *Forecasts and Sensitivity Analyses of Western Coal Product/on,* prepared for Rocky Mountain Energy Co (Washington, D.C.: ICF, Inc., November 1980). From table 3-2, app A

ERA and EIA growth rate taken from table 1, Department of Energy, *Proposed Changes to Generating Capacity 1980.89 for the Contiguous United States, DOE/RG-0047* (Washington, D C DOE, December 1980,) The 25 percent was derived by combining the esti. mates by the Economic Regulatory Administratlon of 21 percent from 1979 to 1983, and latest estimates by the Energy Information Administration of 32 percent from 1978 to 1995

'National Coal Association, NCA Long-Term Forecast (Washington, D. C.: NCA, March 198 1).

growth rate projected by NERC in July 1981 was reduced by 10 percent from their earlier projection, to 3.7 percent.

There are analysts who expect the electrical growth rate to continue to decline in the future. For example, the Solar Energy Research Institute (SERI) projects an electrical growth rate of 0.4 percent annually between 1978 and 2000 if cost-effective efficiency investments are made (excluding investments in solar).[3] According to this study, construction programs already underway could support such an increase in demand over the next 20 years even if: 1) no plants are brought on line after 1985, 2) all fossil plants built before 1961 are retired, and 3) 80 percent of all oil- and gas-burning generating plants are retired. The SERI study also concluded that vigorous onsite solar investments (active and passive solar space and water heating) combined with extensive development of cogeneration and onsite wind and photovoltaic systems could result in a negative growth rate in the demand for electricity between now and the turn of the century.

More important than the overall electrical growth rate in the United States are the regional growth rates in the potential market areas for Western coal. Recent projections by NERC, NCA, and ICF all assume electrical growth rates (EGR) in the far West that are lower than, or near average compared to the United States as a whole. For the period 1980 to 1990 NERC projects an EGR of 3.8 percent in the West compared to a national average of 3.7 percent. ICF projects a slightly lower rate for the West (2.8 v. 3.0 percent from 1979 to 1990) and NCA projects a significantly lower rate in the West than the national average (2.9 v. 3.5 percent) for the same time period.[4] On the other hand, all three of these sources project higher than average electrical growth rates in the Midwest and South-Central United States, both important market areas for Western coal. In much of this area coal from the Gulf Coast lignite province and the Midwest compete with coal from the major Federal coal States.

Another important factor affecting the utility demand for Western coal is the regional growth rate in coal-fired generation. In some areas in the United States, such as in the Midwest, where coal is already meeting most generation requirements, increases in coal demand are fairly directly tied to the growth in demand for electricity. However, in areas like the South-Central United States where coal-fired capacity is being added in a system primarily dependent on more expensive fuel (i.e., oil or natural gas), demand for coal may increase through replacement of oil and/or gas base load generation even if there is no total generation growth. Regional growth rates in coal-fired generation between 1980 and 1990 are projected by NERC to be 3.1 percent in the West (WSCC and MARCA regional reliability councils) and 10.0 percent for the South-Central United States (ERCOT and SPP reliability councils).* NCA projects higher growth rates for essentially the same time period (1979-90) of 5.0 percent in the West and 13.1 percent in the South-Central United States.

It is apparent that the electrical growth rate and conversions from gas to coal in the South-Central United States will be a major determinant in the rate of increase in the demand for Western coal. In 1979 the South-Central United States consumed 26 percent of total Western coal production used by utilities. ** NCA projects that 40 percent of the

[3] House Committee on Energy and Commerce, Report on Building a Sustainable Future, prepared by the Solar Energy Research Institute (Washington, D. C.: U.S. Government Printing Office, April 1981), p, 152,

[4] The geographic areas for these projections do not entirely coincide. The NERC projection is for the Western Systems Coordination Council (calculated from table 19, Electric Power Supply and Demand 1981-1990 (Princeton, N.].: National Electric Reliability Council, July 1981). The ICF projections cover approximately the same area as the WSCC but include parts of Montana and New Mexico that are in other regional reliability councils (calculated from table 3-2, app. A, Forecasts and Sensitivity Analysis of Western *Coal* Production, Washington, D, C.: ICF, Inc., November 1980). The NCA projections include both the WSCC and the Mid-Continent Area Reliability y Coordination Agreement (MARCA) which covers the upper Midwest (see footnote 2 for source).

*ERCOT covers most of Texas and SPP includes north Texas, eastern New Mexico, Oklahoma, Kansas, Arkansas, Louisiana, and the western parts of Missouri and Mississippi, See footnote 4 for sources of projections cited in this paragraph.

**Total Western coal production includes production from the Northern Plains, Rocky Mountain, and Gulf Coast coal provinces, the western part of the Interior coal province, Washington State, and Alaska.

coal produced in the West in 1990 will be used in the South-Central region, and NERC projects that 47 percent of Western coal production for utilities will be used in this area. The reasons for this projected large increase are: 1) replacement of gas with coal-fired generation, as originally required by the Powerplant and Industrial Fuel Use Act (PIFUA]; and 2) higher gas prices. Increases in the availability of natural gas since passage of PIFUA has decreased some of the pressures to switch from gas to coal, and there remains some uncertainty as to how much of a shift from gas to coal will actually occur in this region by 1990,

Sulfur Reduction Standards

Before passage of the 1970 Clean Air Act, sulfur content of coal was not a significant factor affecting utility coal purchase decisions. The 1970 new source performance standards (NSPS) for $S0_2$ that set a maximum emission rate of 1.2-lb/million Btu, created a large market for "compliance" coal (i.e., coal that could be burned without stack gas scrubbing and meet the 1.2-lb standard). * A significant amount of the increased demand for Western coal between 1970 and 1979 can be attributed to the fact that Western coalfields could produce compliance coal that had a delivered price in the Midwest that was lower than the delivered price of high-sulfur Midwestern coal when the added cost of scrubbing the high-sulfur coal was factored in.

The 1977 Clean Air Act Amendments, which required sulfur reduction for all coals burned by utilities, significantly reduced the market advantage enjoyed by low-sulfur Western coal under the 1970 NSPS for SO_2. The 1979 NSPS for SO_2 which apply to new powerplants, establish a dual standard for sulfur reduction based on both sulfur content and maximum allowable emissions of SO_2. ** If 70-percent sulfur reduction will result in an emission rate of less than 0.6 lb SO_2/million Btu, a higher sulfur reduction is not necessary. All higher sulfur coals must have 90-percent reduction in sulfur, but emission of SO_2 cannot exceed the 1970 NSPS of 1.2 lb/million Btu.[5] For "high" sulfur coal, this translates into a maximum of 6.0 lb sulfur/million Btu (90-percent reduction of this amount equals 1.2 lb SO_2/million Btu). For low sulfur coal this translates into a maximum of 1.0 lb sulfur/million Btu (70-percent reduction of this amount equals 0.6 lb SO_2/million Btu). Most current production in the West would qualify for a 70-percent sulfur reduction rate.

The cost of stack gas scrubbing for Western low-sulfur coal is generally lower than for high-sulfur coal because scrubbing processes for low-sulfur coal (mostly dry) are cheaper than wet processes needed for high sulfur coal. However, this advantage is largely offset by allowances in the present regulations that give credit for sulfur reduction by precombustion cleaning (i.e., sulfur reduction by cleaning can reduce the percentage of sulfur reduction required by stack gas scrubbing). According to studies by the Bureau of Mines, mechanical cleaning of coal from northern Appalachia and the Midwest can result in average reductions in sulfur of 33 and 23 percent respectively.' This means that sulfur reduction by stack gas scrubbing would typically need to range from 57 to 67 percent

*This translates into a coal sulfur content of 0.6 lb/million Btu since that amount of sulfur would convert to 1.2 lb of SO_2.

**The final 1979 NSPS were published on June 11, 1979 (44 Federal Register 33613-33624) but apply to all electric utility steam generating units for which construction commenced after Sept. 18, 1978.

[5]The 1979 NSPS have been challenged in court on the grounds that there was irregular ex parte communication during their formulation. The regulations have been upheld in district court and the decision has been appealed by industry, It is possible that the regulations will be revised as a result of this litigation. Legislative modifications to sulfur reduction standards are also in early stages of consideration by Congress. Revisions that would allow a more flexible sliding scale for sulfur reduction would lessen the adverse impact of the 1979 NSPS on the competitive position of Western coal in Midwestern markets, but not eliminate it. For example, the Mining Task Force of the National Coal Policy Project concluded before the 1979 NSPS were promulgated that the Clean Air *Act* Amendments of 1977 (which require utilities to install the best available control technology on all new plants) would mean that coal production in the Northern Great Plains was not likely to increase as much as would happen under the 1970 NSPS. F. X. Murray (cd.), Where We Agree: Report of the National Coal Policy Project V.2 (Boulder, Colo,: Westview Press, 1978).

[6]A. W. Deurbrouck, Sulfur Reduction Potential of Coals in the United States, Bureau of Mines RI 7633 (Washington, D. C.: U.S. Government Printing Office, 1972).

(rather than 90 percent) for Eastern coal compared to 70 percent for low-sulfur Western coal. Coal cleaning is not generally practiced on Western coal primarily because of the generally low heat content of these coals that are used by utilities, and because Western coals tend to be high in organic sulfur, which is not amenable to reduction by conventional mechanical cleaning processes.

The 1979 NSPS for $S0_2$ have not been in effect long enough to allow full evaluation of their effect on coal markets, but it appears that stack gas scrubbing costs for high-sulfur coal (with credits for sulfur reduction by cleaning before combustion) and for low-sulfur Western coal will not differ greatly. If this proves to be the case, it would largely eliminate sulfur content in coal as a key factor in coal purchasing decisions for new powerplants by electric utilities, although there are some situations where Western coal may retain a competitive advantage based on sulfur content. For example, in nonattainment areas where further development hinges on reducing total emission of $S0_2$, low-sulfur coal may have an advantage because full (i.e., 90 percent) stack gas scrubbing of low-sulfur coal emits less total $S0_2$ than the same amount of scrubbing of high-sulfur coal.

In summary, the competitive position of Western coal varies according to the kind of limitations that are set on the emission of SO_2. At one extreme, the absence of restrictions on $S0_2$ emissions would make the delivered price, rather than the sulfur content of the coal, the key factor in purchasing decisions. The 1979 NSPS will probably achieve a similar result. In contrast, the 1970 NSPS gave low-sulfur Western coal a significant competitive edge, and strict limitations on the total level of emissions also favor Western coal.

The full effect of the 1979 NSPS (if they are not modified) will not be felt until the late 1980's because a large percentage of new coal-fired capacity that will come online between 1980 and 1985 was ordered before the NSPS went into effect.[7] The major impacts of the 1979 NSPS in the next decade will be in the effect it has on determining which coal regions will supply those new coal-fired plants that will be built in the late 1980's and that have not signed long-term contracts for coal.[8]

Mine Costs

Now that sulfur content will probably be a less significant factor in the marketing of Western coal, the single most important competitive advantage retained by Western coal is its low cost at the mine mouth. Table 28 summarizes recent representative steam coal contract prices in January and June 1981 for the major Federal coal-producing States and ranges of prices within the Midwestern and Appalachian coal regions. In January 1981, typical price per ton from the Powder River basin in Wyoming and Montana ranged from $6.75 to $12.00/ton, and in the other Western coal States, for higher Btu coal, from $16.00 to $20.75/ton. In contrast, prices for Midwestern coal range from a low of $17.00 to $27.501 ton and for Appalachian coal from $23.00 to $34.50/ton. The actual cost spread is a little less when these prices are translated into cost per million Btu. For example the low price for coal in the Midwest of

‘Eighty-three percent (49,200 of the projected 59,400 gigawatts total net capacity) of new coal plants that are planned to come on line between 1979 and 1985 will be constructed to meet the 1970 NSPS rather than the 1979 NSPS, and an additional 5,800 gigawatts planned to come on line between 1985 and 1990 will be under the old standards because orders for boilers were made before the new standards took effect (numbers calculated from tables 3-7 and 3-9, app. A, Forecasts and Sensitivity Analysis of Western Coal Production, Washington, D. C.: ICF, Inc., November 1980).

[8]It should be noted that the present administration has proposed that the mandatory scrubbing requirements in the 1977 Clean Air Act Amendments be eliminated. However, if the 1979 NSPS are repealed, it is not certain that low-sulfur Western coal would be as attractive to Midwestern utilities as it was in the 1970's. For example, a study by Data Resources Inc. (DRI) has concluded that eastern and Midwestern electric utilities would continue to favor local high-sulfur coal, even if the mandatory scrubbing requirements were dropped (*Coal* Week, May 18, 1981). The reason for this is that DRI's projections of rail rate increases for Western coal offset the cost savings from not having to control the SO_2 emissions.

Table 28.—Representative Mine-Mouth Prices and Transportation Costs for Western Coal (January and June 1981)

	Contract steam coal price (FOB)			Representative rail rates ($/ton)					
State	Btu/lb	$/ton	$/mm Btu	From	To: Minneapolis	Omaha	Kansas City	Chicago	Hammond, IN
Montana	**8,600**	**9.75**	**0.57**	Colstrip MT	11 .46[a] 21.44[b] (22.31)			—	
	9,300	12.00	**0.65**	Decker MT	—		—	18.69[a] (18.26)	18.94[a] (18.00)
Wyoming. . . .	**8,100’**	**6.75 (7.00)**	**0.42 (0.43)**	—	—			—	—
	1 0,500*	**16.50**	0.79	**Hanna WY**	—	**10.89[a] (11.04)**	8.0118.97[a] (9.1 1/10.13)	**12.43a (14.30)**	14.24[a] (16.29)
Colorado	**10,700**	17.50 (19.00)	**0.82 (0.89)**	**Routt CO**	—	**19.65[b] (20.63)**		·	—
	11,600	**20.75 (22.00)**	**0.88 (0.95)**	—	—		—	—	—
Utah.	**11,500**	**20.50**	0.89	**Utah**	**30.25[b] (31.76)**				—
New Mexico .	**10,000**	**16.00**	**0.80**						
Midwest	**9,500 to 12,000**	**17.00 to 27.50 (29.00)**	**0.73 to 1.18 (1.26)**						
Appalachia. .	**11,200 to 13,000**	**23.00 to 34.50 (37.00)**	**0.83 to 1.43**						

[a]Unit train rate
[b]Single car rate
[c]Powder River Basin
‘Southern Wyoming

NOTE Number in parentheses Indicates price change from January to June 1981 No parentheses Indicates no change

SOURCE *Coal Week.* Jan 5, 1981, and June 8, 1981

$17.00/ton is 2.5 times higher than the low price for Western coal, but on a Btu basis the spread is reduced to a factor of 1.7. The low cost of mining Western coal can be attributed primarily to low production, labor and reclamation costs for both surface and underground mines with coal seams that are thicker than those in the Midwest and Appalachia.

Transportation Costs

Western coalfields are located far from the main centers of coal demand in the Midwest and South-Central United States. Consequently, transportation costs are one of the major market disadvantages experienced by Western coal and are probably the single largest overall factor in market decisions concerning Western coal. Table 28 shows some representative rail rates from points in the West to the Midwest, In all the examples shown here, except from Hanna, Wyo., the rail transport costs exceed the mine-mouth cost. The cost advantage of unit train rates is also clearly shown in this table. From Colstrip, Mont., to Minneapolis, Minn., single car rates are almost twice unit train rates. The difference works to the disadvantage of Colorado and Utah where single mines often cannot produce enough to justify commitment of unit trains. Table 28 also shows that rail rates are changing at a faster rate than mine costs in the West. During the first 6 months of 1981 all except one rail rate changed, and most of the changes involved increases of $1.00/ton or more. In contrast, most coal prices in the West remained unchanged during this same period.

There is a general consensus that rail transportation costs over the next 10 years are likely to increase at a faster rate than in-

84-141 0 - 81 - 7 : QL 3

flation.[9] Coal slurry pipelines may reduce transportation costs between certain points, but there is no consensus as to how significant these cost savings may be, nor is there much certainty as to the magnitude of real increases that can be expected in rail transport costs (see ch. 8).[10] However, the net effect of real increases in transportation costs will adversely affect the competitive position of Western coal with respect to Midwestern coal because longer distances are involved.

The alternative to shipping coal to centers of demand is to generate electricity at the mine mouth and ship the energy by wire. North Dakota, which is relatively close to centers of electricity demand in 'the upper Midwest, and New Mexico, which is relatively close to centers of demand for electricity in southern California both export significant amounts of electricity by wire. However, several factors tend to limit the level of minemouth generation to primarily what is needed within the Western Federal coal-producing States and adjacent States: 1) long-distance transmission of electricity is generally expensive because of high capital costs, 2) the availability of water is less (although use of dry-cooling towers can reduce some of the problems related to water availability), and 3) the relative environmental and social impacts of large-scale powerplants are greater in the arid and semiarid West compared to the Midwest and South-Central United States.[11] Transportation by wire is discussed in more detail in chapter 8.

Reclamation Costs

Reclamation requirements under the Surface Mining Control and Reclamation Act of 1977 give Western coal a decided competitive advantage compared to Eastern coal because the relative cost increases attributable to the Act are small in the West compared to the Midwest and Appalachia. Typical incremental costs with Public Law 95-87 have recently been estimated to be $5.24/ton in Appalachia, $1.80/ton in the Midwest and $0.57 ton i n the West.[12] The incremental cost differential because of reclamation requirements between Western and Midwestern coal (a factor of 3) is more significant than the cost differential between Appalachian and Western coal (a factor of 10) because Western and Appalachian coal serve different market areas, whereas the market areas for Midwestern and Western coal overlap. Less stringent reclamation requirements for mining would probably have the effect of improving the competitive position of Midwestern coal with respect to Western coal because cost reductions from less stringent reclamation standards would generally be greater in the Midwest.

Royalty Rates and Severance Taxes

Royalty rates on coal produced in Western States were generally very low before the 1970's reflecting the relatively low value attributed to Western coal reserves. The increased demand for coal in the West in the 1970's resulted in increases in royalty rates

[9] Participants in a conference held in Cctober 1980, shortly after the Staggers Rail Act of 1980 was signed into law reached the general conclusion that there would be an almost immediate impact in terms of increased rates for shipping coal (Coal Week, Oct. 20, 1980). The Department of Energy assumed a 15-percent real increase in rail transportation costs between 1978 and 1985 in setting its preliminary regional coal production goals. However, ICF has found that between 1978 and 1980 alone real increases (i. e., adjusted to account for inflation) were 10.5 percent, almost as much as DOE's projected increase over the 7-year period. This underestimation of likely rail increases resulted in a considerable overestimation of demand for coal from the Powder River basin (ICF, Inc., Analysis and Critique of the Department of Energy's August 7, 1980 *Report* Entitled "Preliminary *National and Regional Coal* Production *Goals for 1985*, 1990 and *1995*" (Washington, D. C.: ICF, Inc., October 1980).] In the final production goals, DOE increased assumed escalation of transportation costs to 25 percent. Rocky Mountain Energy Co. projects a 40-percent real increase in rail transportation costs in southern Wyoming between 1980 and 1990 (personal communication, Stephen Berg-Hansen, Wyoming Task Force, Oct. 16, 1980).

[10] See also Office of Technology Assessment, U.S. Congress, *Coal Slurry Pipelines, Summary* (Washington, D. C,: U.S. Government Printing Office, September 1980), p. 8, This summary updates an earlier report, A *Technology* Assessment *of Coal Slurry* Pipelines (Washington, D. C.: U.S. Government Printing Office, March 1978),

[11] See for example discussion on pp. 199-201 in F. X. Murray (cd.), Where We *Agree:* Report *of the National* Coal *Policy* Project *V.2* (Boulder, Colo.: Westview Press, 1978).

[12] National Research Council, *Surface* Mining *Soil, Coal and Society* (Washington, D. C,: Academy Press. 1981). This study's analysis of reclamation costs is discussed in more detail in ch. 10.

as coal was perceived by both the owners and potential lessees as having a higher value. Indian tribes and private leaseholders led the way in exacting higher royalty rates in the early 1970's. The 1976 Federal Coal Leasing Amendments Act (FCLAA) set minimum production royalty rates on surface coal at 12½ percent; a lower royalty rate (currently 8 percent) is permitted for underground coal. Several States followed suit in raising royalty rates, and new leasing transactions of non-Federal coal generally follow minimum levels set by the Federal Government.

The overall effect of changing royalty rates has been to create considerable differentials in royalties between "old" 'and "new" leased coal. Federal leases before 1976 contained nominal royalties by today's standards. The average royalty rate on Federal coal mined in 1977 was 18.8 centslton. Royalty rates at current contract prices at rates set in FCLAA may be more than 10 times that. The Department of the Interior (DOI) is required to raise royalty rates when leases come up for adjustment, consequently over the next 10 to 15 years as leases are adjusted, there will exist a dual royalty standard that could affect the competitive position of individual Federal leases with respect to other Federal leases and non-Federal coal. Without a systematic analysis of the intraregional and interregional effects of differential royalty rates, it is difficult to draw conclusions concerning the impact of these differentials on coal markets.

Severance taxes* imposed by States also add to the mine-mouth cost of coal. In the Western States severance taxes range from zero in Utah to 30 percent in Montana. A comparison of severance taxes on surface mined coal in the West shows that cost per million Btu is roughly the same in Colorado, New Mexico, North Dakota, and Wyoming (generally 3 to 5 cents/million Btu).[13] Severance tax costs in Montana run three to four times higher. Severance taxes and royalty rates add to the cost of coal, but increases attributable to these sources are relatively small compared to the cost of mining and transporting the coal. Consequently, such difference may cause shifts in the location of the coal production between Western States (as could be the case in Montana,)* or from Western coalfields to other coalfields, but do not have a significant impact on the availability or overall demand for coal.

Industrial Demand

Utah, Colorado, and New Mexico are the only Western States with significant reserves of metallurgical coal. In 1979 these three States supplied only 3 percent of the metallurgical coal that was used by the steel industry although they supplied nearly all of the metallurgical coal used in the West. The rest was produced and mostly consumed in the Midwest and Appalachia. Federal leases in Oklahoma also contain metallurgical coal, and demand for Federal coal from this State hinges strongly on the needs of the steel industry. Even a dramatic increase in the demand for metallurgical coal would not have much effect on the total demand for Western coal, given its small share of that market.

Industrial coal burning in California presents a significant source of potential increased demand for coal from Utah, southern Wyoming, New Mexico, and Colorado, but little realization of this potential is expected within the next 10 years because of the economic costs of converting boilers from natural gas or oil to coal, combined with the costs of emission controls. The same is probably generally true of industrial boiler conversion in the Midwest and South-Central United States where Western coal also experiences competition from Gulf Coast lignites and Midwestern coal production. Significant increases in demand for coal be-

*See ch. 12 of this report for a description of State coal severance taxes.

[13] Colorado Energy Research Institute, Mineral Severance Taxes in the Western States: A Comparison (Golden, Colo.: CERI, 1979).

*The impact of the Montana severance lax is discussed in more detail in the section on market advantages and disadvantages of Montana coal later in this chapter.

cause of industrial boiler conversions are not likely to be experienced until after 1990.[14]

In 1979, 6 percent of total coal production in the far Western States (including Arizona and Washington) was for nonmetallurgical industrial uses, most of which was used for lime and cement kilns, metals processing, and sugar processing (table 22, ch. 4). Some increase in demand for coal for such industrial uses may occur, but dramatic increases are not likely, thus the major potential source of increased industrial demand for coal will be industrial boiler conversions.

Synthetic Fuels

A major disadvantage of coal is that it is not as convenient to use and transport as oil and gas, and is not directly substitutable for use in the transportation sector, which accounted for 25 percent of the total energy use in the United States in 1979. Synthetic gas and liquids can be produced from coal, but at a high cost. Relative costs of oil and gas and coal-based synthetic fuels are still such that synthetic fuels cannot currently compete in the market place, although some large energy companies may be willing to commit funds to commercialization of coal-based synthetic fuels in anticipation of future oil and gas price rises. Nevertheless, demand for coal to produce synthetic fuels during the next decade is likely to depend to a large extent on Government incentives. Coal-derived liquids must also compete with oil shale, which produces a synthetic crude oil that can be processed in conventional refineries. At present the uncertainties in the cost estimates for the various synthetic liquid fuels are larger than the estimated difference in the cost of coal and oil shale derived synthetic liquids.

NCA's long-term forecast for coal production concludes that coal synfuels production will fall short of production goals set by the Federal Government when it created the Synthetic Fuels Corp. NCA estimates that coal synfuels production is not likely to exceed **200,000** barrels per day (bbl/d) of oil equivalent by 1990 in contrast to the goals of 500,000 bbl/d in 1987 and 2 million bbl/d in 1992 established by the Government (of which two-thirds was to have come from coal).[15] NCA stated that the goals were unrealistic considering the economic, technical, environmental, and other regulatory conditions in which synfuels plants must be built.

The current status of coal-based synfuels projects indicates that most of the demand for coal for this purpose during the next decade is likely to be in the Midwest and East rather than the West. A survey by NCA of existing and proposed coal-based synfuel facilities found that the largest coal synfuel facilities operating in the United States are pilot plants in Kentucky and Texas, and that the only large commercial synfuel plant under construction in 1980 was located in Tennessee.[16] According to this survey, of the four large-scale synfuels demonstration plants that were expected to start construction in 1981, only one, the Great Plains Gasification Associates' project in North Dakota, was located in the West. The other three are located in Kentucky, West Virginia, and Illinois.

On the other hand, DOE assumed in its final 1980 coal production goals that 60 percent of the 1990 demand for coal feedstock for synfuels will be west of the Mississippi, most of which (45 percent of total demand) would be from the six major Western Federal coal States.[17] This assumption was based on two major considerations: 1) the technical superiority of low caking Western coal when used with first-generation conversion technology and 2) the relative abundance of low-cost strippable Western coal resources. However, the assumed l-million-bbl/d total U.S. production of coal-based synfuels (20 plants with a capacity of 50,000 bbl/d oil equivalent

[14] F. Hachman, Market Factors Associated With the Assessment of the Development Potential of Federal *Coal* Leases in Utah, prepared for OTA, 1980.

[15] NCA, NCA Long-Term Forecast, op. cit.

[16] National Coal Association. Survey of Existing and Proposed Synthetic Fuel Facilities (Washington, D. C.: NCA, September 1980).

[17] U.S. Department of Energy, The Biennial *Update of National* und *Regional Coal* Production *Goals* for *1985, 1990* and *1995* (Washington, D.C.: DOE, January 1981).

nationwide) exceed other estimates of likely levels of synfuel production by 1990.

Evaluation of this potential for coal-based synfuel development in the West by OTA in the different State assessments generally agrees with the data in the NCA survey, indicating limited development of Western coal to support synfuels plants before 1990, The OTA Wyoming task force judged only one of the three Federal lease blocks in Wyoming that are associated with synthetic fuels projects to have favorable production prospects by 1991 and recent developments have increased the uncertainty that this project will be online by then.[18] The market analyses prepared for the Utah and Colorado task forces concluded that the use of coal for synfuels in those States would be minimal by 1991.[19] The New Mexico task force projections assumed that no commercial-scale synthetic fuel plants using New Mexico coal would be in operation by 1990.[20]

All of the barriers to beginning full-scale construction of the most advanced commercial-scale Western synfuel project in the NCA survey have been overcome. Preconstruction activities began on the Great Plains Gasification Associates' coal gasification facility in Mercer County, N. Dak,, in August 1980. The first unit of the plant, which would use 4.7 million tons per year of lignite, is scheduled to be in operation in late 1984. The project had considerable difficulty in developing a financing plan that was acceptable to the Federal Energy Regulatory Commission and consumers who would purchase the gas. The original financing plan was revised in January 1981, and received approval in May. Citing possible cost overruns and the need for a separate pipeline, the project sponsors increased their loan guarantee request to DOE from $1.8 billion to $2.0 billion. This request was approved by President Reagan in early August 1981.

A study prepared for OTA by the Colorado School of Mines Research Institute on the synfuels potential of Western coal concluded that significant commercial production of high-Btu gas from coal is unlikely for at least 10 years even with Federal incentives.[21] Development activities related to medium- and low-Btu gasification facilities are strongly dependent on the availability of natural gas. The Institute's study concluded that the relative abundance of natural gas, and the prospects for acquiring additional supplies from new foreign and domestic sources have dampened the development of small-scale industrial gasifiers.

This study also concluded that significant commercial production of coal liquids is unlikely over the next 10 years. Even if substantial Government incentives are offered, commercial production levels are expected to be less than 100,000 to 200,000 bbl/d of synthetic liquid, primarily because of the leadtimes for construction and the risks associated with first generation plants. Because of these risks, industry is likely to wait until processes have been demonstrated on a com-

[18] J. R. Boulding and D. L. Pederson, Development and Production Potential of Undevelopcd Federal Coal Leases and Preference Right Lease Applications in the Powder River Basin and other Wyoming Coal Basins, final report (Washington, D. C.: OTA, 1981). The one block with favorable prospects is the Rochhelle lease held by Peabody Coal Co., which is committed to Panhandle Eastern's proposed gasification plant near Douglas. Wyo. This gasification project received a major setback in August 1981 when Pacific Gas & Electric and Ruhrgas Aktiengesellschaft of West Germany announced they were withdrawing from their preliminary partnership agreement for the project. Consequently, it is uncertain whether any synfuel plants will be producing in the Powder River basin by 1991. The other two blocks associated with synfuel proposals are Texaco's Lake DeSmet block in the western Powder River basin and Nerco's Cherokee block in southern Wyoming. These were judged by the Wyoming task force to have uncertain production prospects by 1991. Subsequent analysis by OTA changed 1991 production prospects for the DeSmet block from uncertain to unfavorable. Two other proposed synfuel projects in Wyoming are still in the early stages of development. The Hampshire project proposed for the eastern Powder River basin is not associated with a specific source of coal, and a coal to gasoline plant proposed by Mobil would involve entirely non-Federal coal in the western Powder River basin.

[19] See Hachman, op. cit.: and J. E. Martin, Market Factors and Production Contingencies Determining the Present and Future Demand for Colorado Coal (Lakewood, Colo.: Colorado Energy Research Institute, December 1980).

[20] The Development Prospects for Federal Coal Leases in New Mexico, 1980-1990 (Washington, D. C.: OTA, November 1980].

[21] Colorado School of Mines Research Institute. Synfuels Potential of Western Coal, Draft Report, prepared for OTA, Oct. 31.1980.

mercial scale before committing to build a large synfuels industry. Because commercial demonstration is not possible until the late 1980's, 1990 production levels are likely to be limited to the capacity of the first generation pioneer plants.

Foreign Export

Japan, Korea, and Taiwan are expecting to significantly increase their imports of coal during the next 10 years, and have purchased coal from several Western States for test burns. Initial shipments of coal have been made to Japan from Utah and to Korea from Colorado. Current capacity of port facilities to handle coal for foreign export on the west coast is about 3 million tons, and significant export of Western coal will require considerable expansion of existing facilities and construction of new facilities to handle coal. NCA estimates that countries in the Far East will import from 153 million to 180 million tons in 1990.[22]

Potential competitors to the United States for the coal demand in the Far East are Australia, Canada, China, the Soviet Union, and South Africa. The NCA range of projected coal exports for these countries in 1990 is 195 million to 240 million tons, which is well above the range of import demand in the Far East (although all export from these countries is unlikely to go to the Far East). Consequently, the Western coal States will be entering a competitive market; it is thus difficult to predict what share of this market the United States is likely to obtain. Australia has a considerable competitive advantage over coal produced in the Western United States, but the Japanese in particular appear to be placing limited coal commitments elsewhere as a hedge to limit the strength of the Australian position.[23]

The Japanese have expressed the greatest interest in high-Btu bituminous coal with low ash, moisture, and sulfur content, which gives the Rocky Mountain coal region a probable advantage over the Northern Great Plains. The recent expressions of interest by the Japanese in Powder River basin coal have resulted in plans to construct a coal export facility at Kalama, Wash., that could have an export capacity of 15 million tons by 1983. Export of subbituminous coals from the Powder River basin will probably depend on the development of slurry pipelines and technology for drying the coal to upgrade its heat content. A recent analysis of the economics of export from the west coast did not consider Powder River coal to have significant export potential in the near future, primarily because of its lower heat content.[24] The potential for export of Alaskan coal to the Pacific Rim countries was not examined in this study.

If the Japanese would make firm commitments to purchase significant amounts of Western coal, port facilities could probably be constructed to meet the demand for export. However, such firm commitments have not yet been made, and existing ports that handle coal on the west coast are reluctant to expand or construct new facilities until higher volumes of coal are assured. In the absence of firm commitment by Asian countries to purchase Western coal, it is very difficult to predict the level of foreign exports of Western coal by 1990, ICF projects exports from the west coast to be 2 million tons in 1985 and 14 million tons in 1990.[25] The Interagency Coal Export Task Force projects an upper limit of 15 million tons in 1990 for west coast export.[26] DOE final production goals assume that 12 million to 35 million tons of coal in 1990 will be exported from west coast ports.[27]

[22]NCA, *NCA* Long-Term Forecast, op. cit.

[23]Hachman, op. cit., pp. 24-25.

NOTE: See also, Office of Technology Assessment, U.S. Congress, Coal *Export* and Port Development (Washington, D. C,: U.S. Government Printing Office, April 1981),

[24]G. B. McMeans, Jr., The Economic Viability of Proposed West *Coast Coal* Port Sites (Oakland, Calif.: Kaiser Engineers, Inc., 1981). This paper presented at Coal Outlook's Conference, Charting the *Course* of Western *Coal*, June 8-9, 1981 says "we are not optimistic about the export potential of Powder River Basin subbituminous coals."

[25]Table 4-2, app. A, ICF report cited in footnote 4.

[26]Interagency Coal Export Task Force, Interim Report, DOE/FE-0012 (Washington, D.C.: U.S. Department of Energy, January 1981).

[27]Tables 35, 36, and 37 in DOE report cited in footnote 17.

Institutional Constraints

Later chapters on transportation, environmental, and socioeconomic issues examine in more detail the impacts of various institutional constraints on coal production in the West. There are some specific instances where Federal coal reserves under existing lease cannot be mined because of environmental restrictions, but the total reserves involved in such restrictions are relatively small. * It does not appear that implementation of environmental policies are likely to pose a significant constraint on the ability of Western States to produce coal. Infrastructure constraints, such as the ability of communities to expand services to accommodate population increase because of coal development and the ability of transportation systems to deliver coal to the areas of demand may cause constraints on a site-specific basis. However, such constraints do not appear likely to prevent Western coal States from meeting the possible ranges of demands that are likely during the next 10 years. (See ch. 6 for estimates of production from the Western Federal coal States.)

*See ch. 10, espercially table 93 on p. 317.

Factors Affecting Competition Between Western Coal States

The net result of the various factors and trends discussed in the previous section is that conditions favoring rapid increases in demand for coal from the major Federal coal States are not as favorable for the 1980's as they were in the 1970's, This does not mean that there will not be substantial increases in Western coal production—the low cost of mining Western coal will ensure that—but it does mean that the West's share of coal markets will probably not be as great as has been commonly anticipated. The major reasons for this are: 1) reduction in the low sulfur advantage, 2) lower electrical growth rates. and 3) higher transportation costs. Offsetting these trends somewhat is the likelihood that the South-Central United States, which is a major consumer of Western coal, will have a high growth rate in coal-fired powerplants to replace gas-fired plants. Nearly 60 percent (174 million of 301 million tons) of NERC'S projected new annual demand for utility coal and lignite from the West between 1979 and 1989 will be consumed in the South-Central region (ERCOT and SPP regions). Consequently, the overall demand for Western coal will be highly sensitive to both electrical growth rates and gas to coal conversions in this region. It is more difficult to evaluate the factors affecting demand for coal in the 1990-2000 time period, but some discussion of this can be found later in the Demand for Western Coal; 1990-2000 section.

This section looks in more detail at the relative market advantages and disadvantages that coal producers in each of the major Federal coal-producing States experience with respect to demand for coal in the West and in other parts of the United States. These relative advantages and disadvantages are summarized in table 29. The next section examines the net effect of these advantages and disadvantages in the share of total production and geographic market areas of the different States.

North Dakota

In 1979 North Dakota produced 15.0 million tons of lignite, ranking fifth out of the six major Federal coal States. The key market disadvantage of North Dakota lignite is its low heat content and poor handling characteristics for long-distance transport. Lignite tends to combust spontaneously when exposed to air, and is difficult to unload from rail cars in winter because moisture in the

Table 29.—Major Market Advantages and Disadvantages of the Major Federal Coal-Producing States

Major market advantages	Major market disadvantages
North Dakota	
—Large amounts of surface reserves with easy mining conditions. —Low mine-mouth cost. —Availability of water for onsite development.	—Low heat content and tendency of lignite to spontaneously combust when exposed to air restricts markets almost entirely to mine-mouth development. —PSD air quality limitations may restrict the level of mine-mouth development that is possible.
Montanta	
—Large amounts of surface minable reserves allow high-volume long-term contracts. —Low mine-mouth cost. —Relatively low sulfur content. —Higher heat content compared to the Wyoming Powder River basin,	—Long distance from major coal demand centers in Midwest and South-Central United States means transportation costs are a high percentage of delivered cost. —High severance tax (30%). —Low heat content compared to Rocky Mountain coal States,
Wyoming *Powder River basin*	
—Large amounts of surface minable reserves allow high-volume, long-term contracts. —Very thick coal seams, low strip ratios mean low mine. mouth costs. —Low sulfur content.	—Low heat content compared to Montana and Rocky Mountain States. —Long distance to major coal demand centers in the Midwest and South-Central United States means transportation costs are a high percentage of delivered cost. —Availability of water for onsite development IS limited. —Some current and potential future problems with rail capacity for out-of-State markets.
Southern Wyoming	
—Relatively high heat content. —Moderately extensive reserves of thick multiple seams that can be surface mined. —Central geographic location facilities competition in all Western States except the Southwest. —Reserves well located with respect to existing rail lines.	–Difficult mining conditions (commonly caused by dipping coal beds) increase cost of both surface and underground mines. —Long distance from major coal demand centers in the Midwest and South-Central United States means transportation costs are a high percentage of delivered cost.
Colorado	
—Most reserves are high Btu and low sulfur. —Significant reserves of metallurgical grade coal. —Central geographic position allows marketing in all Western States.	—Majority of reserves must be underground mined, resulting in relatively high mine-mouth costs. —More distant from demand centers in the west coast than Utah and New Mexico. –Transportation costs to demand centers in the Midwest and South-Central United States are higher compared to Montana and Wyoming because most production must cross high mountains and rail routes are not as direct and require more carriers.
Utah	
—High-quality reserves (high Btu and low sulfur), —Significant reserves of metallurgical coal. —No severance tax. —Relatively close to coal demand centers on west coast,	–Most production is from underground mines resulting in high mine-mouth costs. —Southern Utah fields distant from transportation networks. —Very far from major demand centers in the Midwest and South-Central United States. —Some reserves in southern Utah are near National Parks.
New Mexico	
—Large reserves of medium-Btu (9,500-10,500 Btu/lb) low-sulfur coal allows high-volume, long-term contracts with utilities. —High-Btu metallurgical grade coal in Raton Mesa region. —Closer to coal demand centers in Texas than other Northern Plains or Rocky Mountain States.	—Some reserves are not generally well served by transportation networks. —Some coal in Raton Mesa region must be underground mined with higher mining costs. —High ash content of some coals sometimes requires coal cleaning, thus increasing cost.

SOURCE Off Ice of Technology Assessment

lignite freezes. The low heat content limits coal sales almost entirely to nearby powerplants (or synfuel facilities) in the State with some export to the adjacent States of South Dakota and Minnesota. Air quality thresholds, as mentioned previously, are becoming a factor to consider in the use of North Dakota lignite reserves in mine-mouth power and synfuel plants.

The key market advantages of North Dakota lignite are that water is readily available for onsite development and there are large reserves of surface minable lignite that can be mined at a relatively low cost, North Dakota is also located closer to the electricity demand centers in the upper Midwest than other Western States, and reserves are well--suited for commercially available gasification technologies.

Montana

In 1979 Montana produced 32.5 million tons of coal, ranking second among the six major Federal coal States. The major market advantages in Montana are large reserves of surface minable coal, with generally higher heat content compared to other Northern Plains States (but relatively low compared to the Rocky Mountain States). Four counties in the Montana portion of the Powder River basin contain an estimated 32 billion tons of strippable reserves,[28] Mine-mouth costs are generally half that in the Midwest (see table 28) but transportation costs are high, comprising about one-half to two-thirds the delivered cost in the Midwest. The Crow and Northern Cheyenne Tribes have large reserves of coal that do not depend on Federal, State, or private coal to form minable blocks,

Montana has the highest severance tax in the United States, Between 1970 and 1975 (the year Montana's severance tax was instituted) growth rates in coal production in Montana and Wyoming were approximately the same. Between 1976 and 1979 the growth rate in coal production in Wyoming was almost three times that of Montana (19.3 percent compared to 6.5). Several published reports have concluded that Montana's severance tax has depressed the growth rate of coal production in the State and point to the difference in growth rate between Montana and Wyoming as evidence. [29] However the difference in growth rates between the two States can also be attributed to other factors than the severance tax, such as limits on the availability of rail lines to areas for proposed new development, and slightly higher production costs before severance taxes are applied in either State. It is possible that Montana's higher severance tax may increase Wyoming's share of production from the Powder River basin compared to what it would have been without differentials in severance taxes, but no analysis of Montana's severance tax to date has established a clear relationship between the tax and changes in Montana coal production,[30] Whatever its relative impact in Montana and Wyoming, the severance tax remains a small percentage of the delivered price of electricity generated from Powder River basin coal, and despite the high severance tax planned production capacity in Montana during the next 10 years is high (see chs. 6 and 7).

Wyoming

In 1979 Wyoming produced 71,8 million tons of coal, which was 44 percent of total coal production from the six major Federal coal States and more than twice the production from Montana, which was the second ranked State of the six. This high level of production is the result of favorable conditions in the State's coalfields in both the Powder River basin and southern Wyoming. Wyoming has very large (23 billion tons) reserves of surface minable coal in thick coal seams with low stripping ratios in the Powder River

[28] 13 R, E. Matson and J. W. Blumer, *Quality and Reserves of Strippable Coal Selected Deposits, Southeastern Montana*, bulletin 91 (Butte, Mont.: Montana Bureau of Mines and Geology, December 1973).

[29] See for example Coal Age, April 1979, p. 39, and House Committee on Interstate and Foreign Commerce, *Coal Severance Taxes*, hearing report 96-173 (Washington. D. C.: U.S. Government Printing Office, 1980).

[30] Personal communication, Arnold Silverman, professor of Economic Geology a t the University of Montana, Missoula (phone conversation, Feb. 10, 1981].

basin, and also moderate reserves (3.2 billion tons) of medium-Btu coal (9,500 to 10,500 Btu/lb) in southern Wyoming that can be surface mined.[31]

Coal in the Powder River basin of Wyoming is cheaper to mine than anywhere else in the United States. The best coal deposits in the Powder River basin are also well located with respect to rail lines, and are likely to be served by at least one coal slurry pipeline by the mid or late 1980's. The major disadvantage of coal from the Powder River basin is that it has a low heat content, and there are some potential bottlenecks outside of Wyoming in transporting coal by rail to markets to the East and South. Reserves are sufficient to support many mine-mouth conversion facilities, but the availability of water for onsite development, plus other siting problems limits the likelihood of extensive onsite development during the next 10 years.

The central geographic position of coalfields in southern Wyoming, combined with their close location to the Union Pacific Railroad's main line, facilitates competition in States to the East and West. Mining conditions are generally more difficult in southern Wyoming compared to the northern Great Plains both because dipping coal seams are more difficult to mine and also because the more arid climate creates more difficult conditions for reclaiming mined land. As a consequence, mine-mouth prices are higher, even when the higher heat content is taken into account.

Colorado

In 1979 Colorado produced 18.1 million tons of coal, ranking third among the six major Federal coal States. The main advantage of Colorado coal is high heat content and low-sulfur content, reserves of surface and underground coal that are served by existing transporatation networks, significant reserves of metallurgical coal, and a central geographic position that allows marketing in the Southwest as well as the Midwest and west coast.

One of the major market disadvantages is that the majority of reserves in the State must be underground mined, resulting in relatively high mine-mouth costs. However, surface mine production will continue to provide at least half of Colorado's coal output through the 1980's. Transportation costs place Colorado somewhat at a disadvantage in both Western and Midwestern market areas compared to the other States. Utah is closer to west coast demand centers, and New Mexico is closer to both major demand centers in southern California and in the South-Central United States. Even though Colorado is closer to the demand centers in the South-Central United States than Montana and Wyoming, transportation costs are relatively higher because most production must cross high mountain passes and rail routes are not as direct. The mountain passes increase transportation costs because steep grades necessitate more engines and fewer cars than typical unit trains. Also, lines owned by two or three railroads must be traversed to reach most destinations in the Midwest and South-Central United States. Because of these transportation costs, a significant fraction of the coal used by utilities in eastern Colorado comes from Wyoming.

Utah

In 1979 Utah's coal production was 11.8 million tons. The main advantage of Utah coal is high heat content of steam coal, reserves of metallurgical coal, and close location to demand centers on the west coast, The major disadvantages are that virtually all present production is from underground mines, and consequently mine-mouth costs on the average are the highest of any Western State. Fields in southern Utah have significant surface minable reserves, but are distant from existing transportation networks. Twenty-four million tons of the Alton field reserves in southern Utah nearest to Bryce Canyon National Park have been designated by DOI as unsuitable for mining, Utah is also very far from coal demand centers in the Midwest and

[31]Reserve data from table 9, G. B. Glass, Wyoming *Coal Fields, 1978*, inf. cir. No. 9 (Laramie, Wyo.: Geological Survev of Wyoming, 1978).

South-Central United States with consequent high transportation costs, Nevertheless, Utah coal, because of its high heat content and low sulfur content has penetrated these markets (see fig. 20).

New Mexico

In 1979 New Mexico produced 15.1 million tons of coal, slightly more than fifth-ranked North Dakota. The major market advantages of coal in New Mexico are the presence of moderate reserves of medium-Btu (9,500 to 10,500 Btu/lb) surface minable coal in the San Juan River region, sufficient to supply high-volume, long-term contracts with utilities. The Raton Mesa coal region has high-Btu coal, but a substantial fraction must be underground mined and thus has a relatively high mine-mouth cost per ton. New Mexico is closer to coal demand centers in Texas than other Western coal-producing States and this represents a significant potential market that has as yet been unrealized because some of the existing coal leases are not well served by transportation networks. Extensive development of coalfields in the San Juan basin depends on construction of the Star Lake-Bisti Railroad. A significant disadvantage of some New Mexico coal is that some of the major coal deposits in the San Juan River region are quite uniformly high in ash content (generally greater than 14 percent) and cleaning to reduce ash adds to the cost of using the coal.

The Market Area of Western Coal States

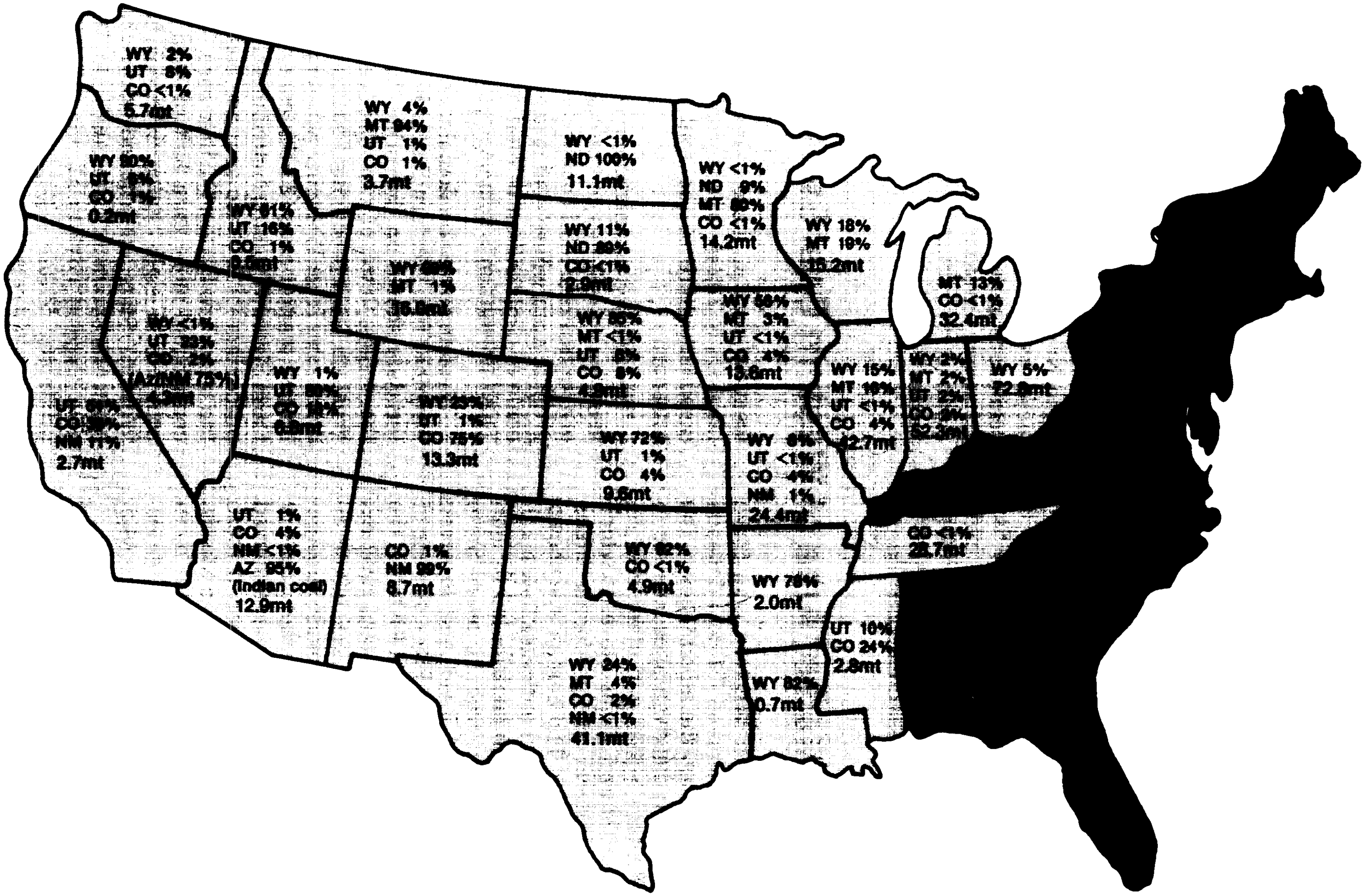
The share that each Western coal State has in fulfilling the demand for coal depends on the extent to which the advantages in the State outweigh the disadvantages relative to the other Western States and other coal regions. Figure 20 shows all the States to which the six major Federal coal-producing States shipped coal in 1979, The percentage shown in each State on the map indicates how much each Federal coal State contributed to total State use of coal. Coal went to every State west of the Mississippi River and to seven States east of the Mississippi River. In none of the States east of the Mississippi River did the combined contribution of Western coal exceed 37 percent of total coal use, which indicates that Western coal has made substantial inroads into the central market areas of the Midwest coalfields, but has not achieved market dominance* over local coal in these areas. On the other hand, west of the Mississippi River, Western coal contributed more than half of coal use within all but two States, showing a clear market dominance over Midwestern coal in these markets. The exceptions are in Texas, where local lignite has the dominant share of the coal market and in Missouri.

The relative competitive position of the six Western coal States can be measured by several indicators: total coal production, the geographic area where coal is sold, and the percentage contribution to total State coal use. This information is summarized in table 30.

Wyoming's market dominance compared to the other five Western States is evident from the data shown on this table. Wyoming has the largest level of coal production of any Western State producing Federal coal. In addition coal from Wyoming was shipped to the largest market area (22 States) and in 11 of those States Wyoming contributed the largest percentage of in-State coal use compared to the other five States. Furthermore, Wyoming contributed more than half of total in-State coal use in eight States, whereas no other Western State contributed more than this percentage in more than one State. Wyoming also shipped coal to all the Western coal-producing States except Arizona and New Mexico. Wyoming coal's cost competitiveness

*Note that the term "'market dominance"" is used here to refer to coal that has a strong competitive edge in a certain market area. The specific meaning of market dominance as used in railroad ratemaking is not meant.

Figure 20.—Market Areas of the Six Major Federal Coal-Producing States



NOTE: Only those States using coal from Montana, New Mexico, North Dakota, Colorado, Utah, and Wyoming are shown. Percentage indicates supplying State's share of user State's coal demand in 1979. Number is in millions of tons and is total State coal use/shipments received.

SOURCE: U.S. Department of Energy, *Bituminous and Subbituminous Coal and Lignite Distribution, Calender Year 1979* (Washington, D.C.: U.S. Government Printing Office, April 1980).

Table 30.—Market Relationships Between the Six Major Federal Coal-Producing States

State	1979 production (mmt)	Market area (Excludes the supplying State)	Contribution to out-of-State use[a] <10%	10-50%	>50%	No. major synfuels proposals[b]
Wyoming	71.8	22(11)[c]	9	5	8	5
Montana	32.5	8(4)	4	3	1	2
North Dakota	15.0	2(1)	1	—	1	5
Colorado	18.1	22(2)	19	3	—	1
New Mexico	15.1	4(0)	2	1	1	1
Utah	11.8	16(3)	12	3	1	1

[a]Numbers in column indicate the number of States coal was shipped to in 1979 in each Category. Data derived from figure 20.
[b]Only projects that would produce more than I0,000 bbl/d oil equivalent of synthetic natural gas or liquids from coal are included As of January 1981 none of the proposals listed here was at a stage where production of synthetic fuels was certain Compiled from Colorado School of Mines Research Institute, Synfuels *Potential of Western* Coals, Draft, Oct 31, 1980, prepared for Off Ice of Technology Assessment, and a listing of DOE synfuel project awards In *Coal* **Week, Dec.** *22, 1980.* The number for Wyoming Includes a feasibility study being conducted by Rocky Mountain Energy Co. for a synfuel plant to develop a Federal lease in southern Wyoming and a Utah facility, neither of which is listed in either of the previously cited sources
[c]Number in parentheses indicates the number of States where there is market dominance compared to the other five States (I e., the State supplies the largest percentage of in-State coal used comdared to the other five States. but is not necessarily the dominant supplier in the State).

SOURCE Office of Technology Assessment

compared to Colorado coal along the Front Range urban corridor in Colorado, arising from transportation factors, is shown by the fact that Wyoming contributed almost one-quarter of Colorado's total coal use in 1979.

Montana is the State with the next greatest competitive advantage, as measured by total coal production. In 1979 Montana produced almost twice as much coal as Colorado, the next largest coal producer. However, it is apparent that market dominance in terms of magnitude of coal production is not necessarily accompanied by dominance in terms of geographic market area, as can be seen in the cases of Colorado and Utah. Both States ranked below Montana based on coal production, but both Colorado and Utah have very large geographic market areas compared to Montana, North Dakota, and New Mexico. In fact, Colorado shipped coal to as many States as Wyoming. However in only a few States did Colorado or Utah contribute the highest percentage of total State coal use, and in a large majority coal shipments represented less than 10 percent of total coal use.

The main reason magnitude of coal production and the size of market area do not always coincide is that utilities use much larger volumes of coal than industrial users. The low cost of surface mined coal in the Powder River basin, along with large blocks of reserves that can sustain high production rates for long-term utility contracts have been the key factors in the market dominance (in terms of magnitude of coal production) enjoyed by Wyoming and Montana. The high quality of coal in Colorado and Utah (high heat content and availability of metallurgical coal) allows a large geographic market area through sale to industrial users, spot market utility sales, and sale for blending with high-sulfur Midwestern coal. However, the high cost of producing and transporting this coal has significantly limited total production compared to Montana and Wyoming. New Mexico is perhaps the only Western State in which the relationships described here may change significantly during the next 10 years. At the present time New Mexico does not export significant amounts of coal out-of-State. However, Texas represents a significant potential market that could possibly use 20 million tons of New Mexico coal by 1990. *

Table 30 also lists the number of large-scale synthetic fuel plants that are in active planning stages in each State. All of these projects, except one in North Dakota, are still in early planning stages, and there is no cer-

*The OTA New Mexico Task Force estimated that 20 million tons or more of coal would he shipped to Texas markets in 199o. This seems to be optimistic (see discussion of forecasts of demand for New Mexico coal later in this chapter).

tainty whether, or when, they will be constructed. North Dakota has a large number of possible plants because the reserves are well--suited for conversion to synthetic gas, and water needed for cooling and conversion processes is more readily available than in other Western coal States. Wyoming has a large number of proposed projects due primarily to the availability of reserves in both the Powder River basin and southern Wyoming to support such facilities, but availability of water is more of a problem than in North Dakota. Projects in the active planning stage in the remaining four States range from one each in Colorado, New Mexico, and Utah to two in Montana.

The discussion of synthetic fuels earlier in this chapter indicated that significant levels of coal production for synthetic fuels were unlikely before 1990. The capacity in 1990 of the only two projects that were judged by OTA to have a good chance of being in operation before 1990 (the Great Plains Gasification Project in North Dakota and Panhandle Eastern's proposed gasification project in northeastern Wyoming) is 12 million tons, but it is uncertain whether either would be producing at full capacity by 1990.[32] Levels of coal production for synthetic fuels could become significant after **1990.** Coal consumption of currently proposed commercial-scale synthetic fuel plants that would use coal from the major Federal coal States would be 95 million tons per year at full capacity. Attainment of full capacity might be reached in the mid to late 1990's.

'- Boulding and Pederson, op. cit.
"Calculated from tables VI-2 and VI-3, NCA, *NCA Long-Term Forecast*, op. cit.

Projections of Demand for Western Coal: 1980-90 and 1990=2000

There is no way to predict with certainty the demand for coal from the major Federal coal States over the next 10 years, but it is possible to estimate demand. Numerous estimates (usually called forecasts or projections) concerning demand for coal from the West have been made for the 1985-90 period that was the focus of OTA's analysis of existing Federal leases.

Production and Demand Forecasts and Production Goals

Coal forecasts fall into two major categories: 1) production projections that are based on production commitments under existing contracts and potential production based on industry plans to open new mines and expand production at existing mines, and 2) demand projections based on computer models that assume certain conditions in coal markets and allocate coal production to different coal regions based on varying assumptions about factors such as mining and transportation costs and electrical growth rates. Production forecasts are most useful for evaluating changes in coal production over the short term (up to 5 years or so in the future) whereas demand forecasts are most useful for evaluating intermediate and long time periods (greater than 5 years). Each approach has its own advantages and limitations.

Production Forecasts

These forecasts are more directly related to the "real" world because they are based on contractual commitments and specific industry plans. Production forecasts based on industry plans for new mine openings and mine expansions are frequently high because such plans are based on individual company expectations of the share of market demand they will be able to capture. Some of the expected market share may be captured by other competitors and consequently actual production may be less than production based on industry plans. Also, coal contracts usually specify a range of possible delivery rates. If electric utilities need less than the maximum amount contracted for, then forecasts based on contracts will overstate production. For example, in the Powder River basin of Wyoming, deliveries to utilities in 1979 and 1980 averaged about 5 percent lower than would be expected based on contractual commitments. ” Production forecasts can change quite rapidly in response to changed perceptions by the coal industry of likely demand. For example the projected capacity for coal mines in Carbon, Sevier, Wayne, and Emery counties in Utah for the year 1985 dropped from 45.2 million tons in a 1977 survey to 26.5 million tons in a 1979 survey .3’ One value of production forecasts is that they can serve as an indicator of the capacity of the coal industry to respond to changes in demand.

Demand Forecasts

Based on computer models, these forecasts are not very reliable for making point forecasts for a single year because small errors in assumptions used in making the forecast can result in large differences in projected amounts. On the other hand, computer models are very useful in evaluating the sensitivity of demand for coal to changes in conditions such as the electrical growth rate and in identifying possible ranges in demand in response to different conditions. The range of possible demands generated by computer models using different assumptions can be so great that ultimately identification of a “most likely” range of demands must be based on human judgments by individuals knowledgeable about current coal market conditions and an understanding of the impact that existing trends and possible changes in these trends will have on future demand. Evaluation of forecasts from a number of different sources allows the development of a range of “most likely” demands in which a higher degree of confidence can be placed than the range of possible demands that may be generated by a single computer model.

An important element in OTA’s evaluation of the production potential from existing Federal coal leases was to identify a most likely range of demands for coal from the major Western coal regions and States with Federal leases. This identification of probable ranges in demand generally involved a four step process: 1) review of existing projections from different sources, 2) development of independent projections by OTA based on evaluation of market conditions in the specific regions or States of interest, 3) development of estimates by OTA State task forces based on review of projections identified in steps 1 and 2 and/or the development of new estimates representing the collective judgment of task force members, and 4) further evaluation and modification of task force estimates by OTA to identify a range of demands which could be compared to other estimates of production potential from existing Federal leases. *

Production Goals

OTA also paid particular attention to two sets of forecasts that became available after most of OTA’s task force meetings had been completed: 1) the August 1980 preliminary coal production goals and the January 1981 final production goals developed from DOE’s National Coal Model[36] and 2) refinements to the National Coal Model forecasts developed by ICF, Inc., using its Coal Electric Utility Model.[37] DOE’s final production goals were

“Personal communication with Gary Glass, Geological Survey of Wyoming, September 1981.

“The 1977 and 1979 Keystone Coal Surveys reported in Coal Age, February 1978; and Coal Age, February 1980, respectively.

*Special market analyses were prepared for OTAA on the Powder River basin and southern \\’yoming, Utah, and Colorado. The Utah, Wyoming. Colorado, and New Mexico task forces each discussed various ranges of likely demand in the years 1985 and 1990 ([he bases for these projections are summa rized in footnotes in table 31]. In most instances () ΓA modified the ranges discussed by the task forces to include a wider range for purposes of a na] yzing production potential from existing Federal leases,

"*Preliminary National and Regional Coal Production Goals for 1985, 1990, and 1995* (Washington. 1).(; .: DOE. Aug. 7, 1980); and The *1980 Biennial Update of National Regional Coal Production Goals for 1985. 1990, and 1995* (Washington, 1). C.: I) OF, January 1981.)

"The ICF forecasts are reported in *Analysis and Critique of the Department of Energy's August 7, 1980 Report entitled* “Preincreased substantially over the preliminary goals (see tables 31 and 32). The final national goals average 16.6, 15.7, and 26.0 percent higher than the preliminary goals for the years 1985, 1990, and 1995 respectively. The final DOE goal for 1985 (1.118 million tons) is very close to both the ICF and NCA forecasts (see table 32), but the 1990 and 1995 DOE final goals (1,620 million and 2,214 million tons respectively) are considerably higher than recent Projections from other sources for the same time periods. The 1990 DOE final goal is almost 300 million tons higher than the highest recent forecast shown in table 32 and the 1995 DOE final goal is almost as high as the high "likely" projection for 2000 shown on table 32.

The reason for the increases from the preliminary to the final DOE production goals appear to be primarily a clearer conceptual definition of the relationship between coal production goals and other coal production forecasts. As the report on the DOE final goals says:

> The goals developed here are based on national energy needs, existing and emerging national and international policies and laws that affect coal demand and supply, and market conditions, By comparison, energy forecasts are generally based on expected market conditions and energy laws and regulations. Since many of the assumptions underlying the production goals are based on policy initiatives to expand domestic coal production, the goals are likely to exceed coal production forecasts ., , Such a relationship is entirely appropriate.

The assumptions that were used in setting the preliminary production goals appeared consistent with a forecasting approach rather than a production goal approach to modeling. Thus, the difference between the final and preliminary goals can be attributed mostly to assumptions concerning implementation of Government policies that will increase demand for coal. * For example, the final production goals assume 1 million bbl/d oil equivalent of coal-based synfuels production in 1990 (in accordance with goals set when the Synthetic Fuels Corp. was established) and strict enforcement of the 1990 deadline in PIFUA for utility and industrial boiler conversions from gas to coal. It does not appear likely that these goals will be met by 1990. The synfuels assumptions in the final production goals substantially exceed those in recent coal production forecasts (see Synthetic Fuels section), and section 301(a) (the off gas requirement) of PIFUA has been repealed by Congress, although rising prices for natural gas will serve as as incentive for conversion from gas to coal.

The final production goals are listed in most tables and figures in this chapter to show their relationship to other production forecasts, but are not considered in detail in the evaluation of the likely range of coal demand in the major Federal coal States because the assumptions on which the final goals were developed probably overstate the impact of Government policies on increasing overall demand for coal in the United States.** However, the preliminary produc-

---

Continued from p. 101

liminary National and Regional Coal Production Goals for 1985. 1990 and 1995 (Washington D. C.: ICF, Inc., October 1980). ICF originally developed the National Coal Model that is used by DOE 10 develop production goals., and has since refined this model into the Coal Electric Utility Model (CEUM). ICF's critique of the DOE preliminary goals identified a number of structural deficiencies in the model, and deficiencies in data and assumptions used in the mode]. Examples of structural deficiencies include such things as coal production and demand regions not coinciding with DOI coal production regions necessitating often arbitrary allocation of model outputs between regions, and distortion of transportation cost due to using average distances between large regions (e. g., transportation costs for southern Wyoming are calculated using an average distance from the Powder River basin.) Examples of deficiencies in data and assumptions include out-of-date coal reserve data in several regions, and unrealistically low assumptions about increases in transportation costs (see footnote 9). The ICF forecasts correct many of these problems, although ICF emphasizes in its analysis that no modeling forecast can be considered definitive, and that the results of forecasts must be interpreted and used with judgment. Some of the deficiencies pointed out by ICF were corrected in preparing the final goals (i.e., analysis was based on DOI supply region and higher transportation costs were used) but other changes in assumptions were made that makes comparisons between the ICF base case and DOE final production goals more difficult.

'See p. 79 for additional discussion of the conceptual distinction between Government policies that change the framework of the market system and policies that influence the market system directly to increase demand for coal.

**it should be noted that in some instances (Colorado in particular) the final production goals are lower than the pre-

Table 31.—Comparison of Demand Projections for Major Western Federal Coal Regions and States With OTA Task Force Demand Estimates

		Forecast (million tons per year)						
		DOE NCM			ICF CEUM			
Region/State	Year	Low	Medium	High	Low	Base	High	OTA task force estimates
Fort Union (North Dakota	1985	23 (29)	23 (29)	28 (29)	23	26	26	—
and Montana)	1990	31 (35)	48 (51)	73 (60)	27	27	32	—
Powder River (Montana	1985	129(187)	159(193)	223(222)	138	169	194	169 to 177
and Wyoming)	1990	186(206)	275(295)	438(412)	163	226	382	199 to 212
Rocky Mountain coal province								
Wyoming (excluding	1985	43 (55)	50 (58)	52 (67)	29	38	43	38
Powder River)	1990	55 (60)	58 (71)	63 (82)	29	36	52	42 to 51
Colorado	1985	33 (34)	36 (34)	39 (38)	26	35	51	at least 25-26
	1990	38 (28)	42 (35)	45 (43)	35	52	95	at least 32-38
Utah	1985	25 (25)	29 (30)	31 (35)	14	16	20	15 to 18
	1990	41 (36)	43 (49)	52 (63)	15	27	59	18[a] to 30[a] to 40[a]
New Mexico	1985	32 (33)	34 (38)	40 (44)	28	30	32	about 30
	1990	43 (56)	57 (64)	61 (67)	46	58	115	up to 72

[a]Estimates made for central Utah only.

NOTE: First number is DOE preliminary production goal which was analyzed by ICF The number in parenthesis is the final DOE coal production goal

SOURCES. DOE Preliminary National Coal Model and ICF Coal Electric Utility Model forecasts taken from tables 3-5A, 3-5B, 3-7A and 3-7B in ICF, Inc., Analysis *and Crltique of the Departmenf of Energy's Aug 7, 1980 Report Entitled, "Preliminary National and* Regional *Coal Product/on Goals for 1985, 1990 and 1995"*, prepared for Rocky Mountain Energy Co, (Washington, D C.. ICF, Inc. October 1980),
DOE Final Production Goals taken from *The 1980 Biennial* Update of *Nafional and Regional* Coal *Production Goals for 1985, 1990 and 1995* U S. Department of Energy, Leasing Policy Development Off Ice, January 1981.
Off Ice of Technology Assessment Task Force projections from following sources:
Powder River Basin and southern Wyoming. Wyoming Task Force, Oct 14-18, 1980. Most likely demand in Wyoming taken from G B. Glass, *Wyoming* Coal *Production and Summary of* Coal *Contracts* (Laramie, Wyo. Wyoming Geological Survey, 1960), and likely high demand taken from J J. Sebesta, *Demand for Wyoming Coal 1980-1991 Based Upon Protected* Utility Coal *Market* (Washington, DC.. Office of Technology Assessment, October 1980) with slight modifications by the Wyoming Task Force as reported in J. R. Boulding and D. L. Pederson, *Development and Production Potential of Undeveloped Federal Coal Leases and Preference Right Lease Applications in the Powder River Basin and Other Wyoming* Coal *Basins* (Washington, D.C. Off Ice of Technology Assessment, 1981), Likely high demand for Montana Powder River Basin taken from J. J, Sebesta, *Demand for Montana* Coal *1980-1991 Based Upon Projected* Utility Market (Washington, D C.. Off Ice of Technology Assessment, October 1980). Most likely projections for the whole Powder River Basin derived by adding Sebesta's Montana projections to Glass' Wyoming projections, and likely high demand derived by adding Sebesta's Wyoming and Montana projectlons Note that the Glass and Sebesta projections for southern Wyomlng in 1985 are the same, so there is no range shown
Colorado Estimates by Colorado Task Force, Sept 22-24, 1980, represent minimum production expected from existing contracts, mine plans, and undeveloped leases, as reported in J E Martin, Market Factors *and Production Contingencies Determining the Present and future Demands for Colorado Coal* (Lakewood, Colo.: Colorado Energy Research Institute. December 1980),
Utah Off Ice of Technology Assessment Task Force, Feb. 2529, 1980 Low to high range was developed by the task force Most likely production is from F Hachman, *Market Factors Associated With the Assessment of Development Potential of Federal Coal Leases in Utah,* prepared for the Office of Technology Assessment, 1980 Total excludes production from Alton Mine or for the Allen-Warner Valley Complex
New Mexico OTA New Mexico Task Force, Aug. 26-27, 1980 Estimates developed by task force as reported in *The Development Prospects for Federal* Coal Leases in New Mexico 1980-7990 (Washington, D C : Office of Technology Assessment, November 1980) The 1990 projection was based on a number of optimistic assumptions including that a major new market for New Mexico steam coal (about 20 million tons per year) will develop in Texas and the gulf coast, and that demand for electricity in New Mexico and the Western region will grow at 4 percent during this period

tion goals are more comparable with other coal production forecasts and are analyzed in this chapter as such.

Table 31 summarizes the DOE, ICF, and OTA task force projections for the Fort Union and Powder River coal regions, southern Wyoming, Colorado, Utah, and New Mexico.* Figure 21 compares these projections schematically for the Fort Union and Powder River regions and southern Wyoming, and figure 22 illustrates these projections for Colorado, Utah, and New Mexico.

It should be kept in mind when comparing the DOE, ICF, and OTA task force forecasts that they were derived by very different methods, The model forecasts are based on varying assumptions concerning factors affecting the overall demand for coal in the United States: this demand is then allocated

liminary goals. This is apparently due to the fact that refinements in the model (such as increasing transportation costs) offset the other assumptions that increased the overall national (():] 1 production goals.

*Since most coal production from the major Federal coal Slates will come from the Powder River region (50 percent or more), demand projections for this area were analyzed in greater detail by OTA. Projections discussed in this chapter include only the DOE, 1(; F'. and OTA task force projections to allow general comparison with projections for the other Federal coal regions and St;] tes. Analysis of other projections for the Powder River basin can be found in ch. 7.

Table 32.–Demand and Production Forecasts for Coai for the United States: 1985-2000
(millions of tons)

	1985			1990			1995			
	Low	Medium	High	Low	Medium	High	Low	Medium	High	2000
EIA production forecasts (1979)	1,129	1,130	1,129	1,305	1,343	1,353	1,592	1,715	1,718	—
Council on Environmental Quality (1979)	–	–	–	–	—	—	—	—	—	899-1850[a]
Exxon (1979)	–	–	–	–	1,285	–	—	–	—	2,219
DOE preliminary production goals (1980)	880	963	1,080	1,089	1,375	1,762	1,238	1,718	2,322	—
ICF CEUM forecasts (1980)	915	1,016	1,082	1,122	1,300	1,791	1,380	1,756	2,976	—
Data Resources, Inc. (1980)	–	987	–	–	1,290	–	—	1,617	—	1,931
National Coal Association (1981)	878	1,015	1,131	1,092	1,345	1,540	—	—	—	—
DOE final production goals (1981)[b]	1,040	1,118	1,245	1,270	1,620	1,986	1,519	2,214	2,766	

[a]Range is for low and high energy growth scenarios analyzed by CEQ. Numbers are recalculated from table 6 using an average of 20 million Btu/ton rather than the 23 million Btu/ton used by CEQ in order to account for declines in average coal heat content as Western coal production increases. The 20 million Btu/ton is taken from the national average projected in 1990 by Congressional Research Service project Interdependence: U.S. and World Energy Outlook Through 1990, Senate Committee on Energy and Natural Resources, Pub. No. 95-31 (Washington, D. C.: U.S. Government Printing Office, 1977).
[b]Included for comparison to forecasts. See discussion in text for difference between the DOE production goals and production forecasts.

SOURCES (in order listed in table):
Table 4.26, V.III Energy Information Administration, *Annual Report* to *Congress, 1979* (Washington, DC.: U.S. Government Printing Office, 1980).
Council on Environmental Quality, *The Good News About Energy* (Washington, DC.: U.S. Government Printing Office, 1979).
Exxon Co., U.S. *Energy Outlook 1980-2000* (Houston, Tex. Exxon USA, December 1979), p. 12.
U.S. Department of Energy, *Preliminary National and Regional Coal Production* Goals *for* 1985, 1990 *and 1995* (Washington, DC.: DOE, Aug. 7, 1980).
ICF, Inc. *Analysis and Critque of the Department of Energy's August 7, 1980 Report Ent/tied "Preliminary National and Regional Coal Production* Goals *for* 1985, 1990 *and 1995"* prepared for Rocky Mountain Energy Co. (Washington, D, C.: ICF, inc. October 1980),
Data Resources, Inc., production forecast as reported in Coal Week, Sept. 22, 1980.
National Coal Association *NCA Long-Term Forecast* **(Washington, D. C.: NCA, March 1981).**
U.S. Department of Energy, *The 1980 Biennial Update of National and Regional Coal Product/on* Goals *for* 1985, 1990, *and 1995* **(Washington, D.C., DOE,** January 1981).

to different regions or States. A fundamental weakness of all computer models is that they are least accurate when results are disaggregate to small geographic regions. The reason for this is that when modeling complex systems, simplifying assumptions must be made. At the aggregate level, simplifying assumptions that may distort results one way or another tend to cancel each other out. At the specific geographic level, small changes in assumptions may create large shifts in projected demand between regions.[38] It must also be realized that models reflect the assumptions, perceptions and biases of the model manager. In addition, models tend to seek optimal (least cost) solutions to fuel procurement and the entire system tends to approach a general equilibrium solution. Rarely, if ever, are these conditions totally achieved in reality.

The OTA task force estimates, on the other hand, were developed based on analysis and judgments by a group of people familiar with the effect that specific conditions in the region or State could have for the demand for coal from that area. The advantage of this approach is that it reflects a sensitivity to local conditions that a computer model cannot have. The disadvantage of this approach is that events or conditions outside of the State or region might affect demand for coal from that region in ways not anticipated by the task force. There is also a possibility that individuals closely associated with development in a region or State may underestimate the effects of competition from another region or State.

The value of looking at both kinds of forecasts is that the two can be used as a check against each other. If several different forecasts are in close agreement, then it can be expected with a reasonably high level of confidence that actual production will be close to the levels forecasted. On the other hand, if different forecasts of the "most likely" level of production differ substantially, then a closer look at the forecasts is merited to try to understand the reasons for the differences.

Given the inherent uncertainty in forecasts, it is necessary to identify a range* to

[38] Additional discussion of this problem can be found in the ICF report cited previously and also in Energy and Environmental Analysis, Inc., Feasibility of Using Coal Market Projections To Appraise Potential Production of Federal Coal Leaseholds, draft report prepared for OTA, 1980.

* It should be noted that this range is distinctly different from the kinds of ranges developed by computer models such as the

account for contingencies and factors that cannot be predicted, The rest of this section examines more closely the different forecasts in the regions and states shown in figures 21 and 22, identifying, where possible, the reasons for divergence between the forecasts.

Fort Union Region

Virtually all production from this region comes from North Dakota; only 0.5 million tons were produced in the Montana portion of the Fort Union region in 1979, compared to 15.0 million tons in North Dakota. The DOE and ICF forecasts are in close agreement in 1985 (see fig. 21) but diverge widely in 1990 with the ICF high forecast nearly the same as the DOE low forecast. OTA did not convene a task force for this region, so no projections are available for comparison, but OTA's evaluation of existing leases found that 30 million tons would be needed to meet the requirements of existing and new coal conversion facilities currently planned or under construction. Given the leadtime necessary to construct these large facilities, it appears that demand for Fort Union coal in 1990 is likely to be closer to the ICF forecast than the higher DOE forecasts.

Powder River Basin

All three forecasts show quite good agreement for 1985 (see fig. 21) with the ICF base case of 169 million tons exactly the same as the OTA task force most likely production estimate, and DOE's medium forecast 10 million tons lower. However, OTA's likely high demand in 1985 is considerably lower than the DOE and ICF high forecasts. In 1990 there is considerable divergence between the three forecasts, with OTA's likely high estimate of 212 million tons being 14 million tons lower than the ICF base case, and 63 million tons lower than DOE's medium forecast. The main reason the DOE forecast is so much higher than the ICF forecast is that the DOE forecasts included unrealistically low increases in transportation costs that were modified in the ICF forecast. OTA used the DOE medium forecast as its high-demand scenario for analysis of production potential of leases, even though it is probably beyond the range of "likely" high production levels. (See ch. 7 for further discussion of demand for Powder River basin coal,)

Southern Wyoming

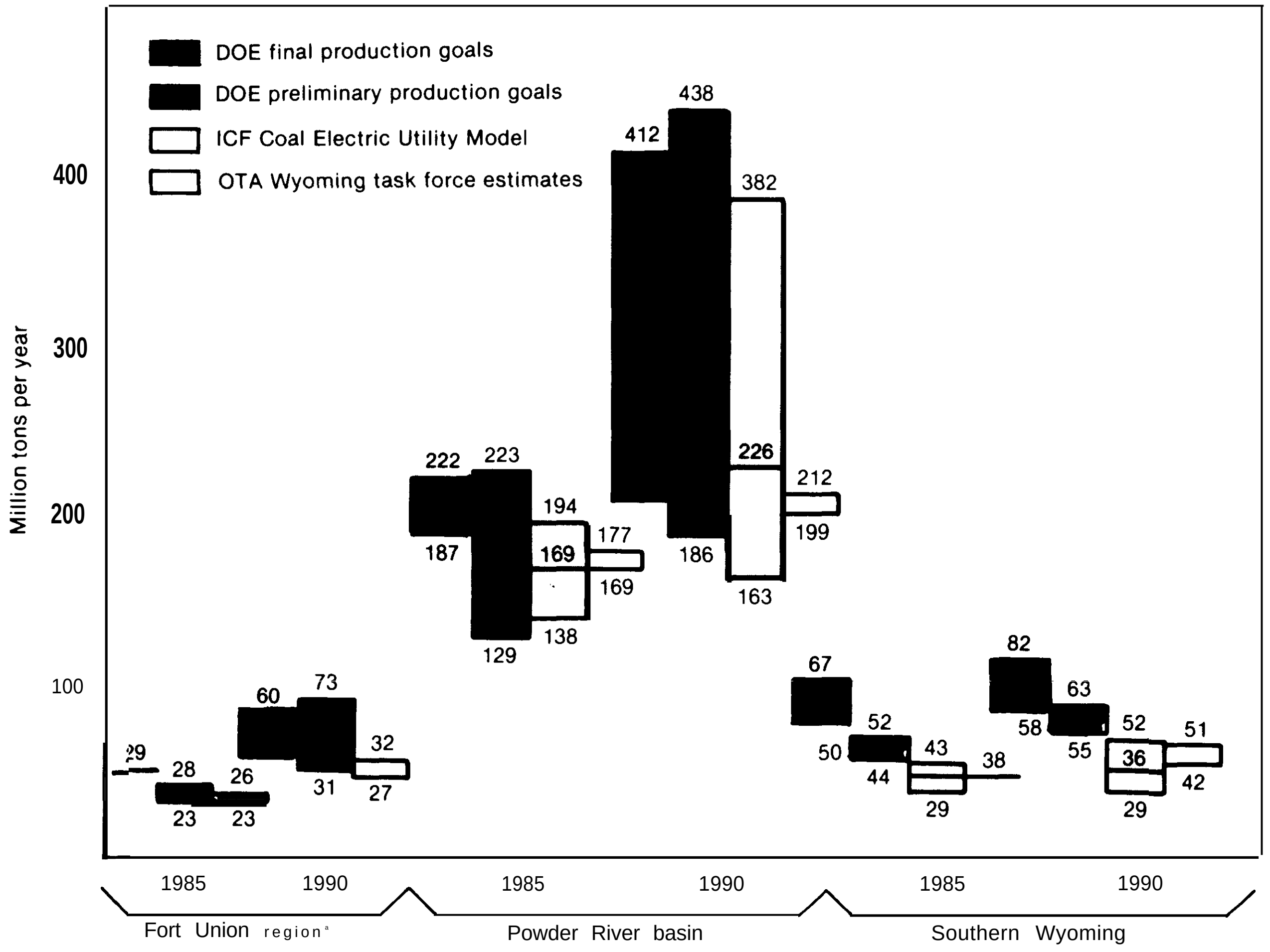
The OTA task force and ICF projections of 38 million tons for southern Wyoming are exactly the same in 1985 (see fig. 21) and are considerably lower than DOE's midrange forecast of 50 million tons, In fact, DOE's midrange forecast for 1985 is almost the same as the OTA likely high estimate of 51 million tons for 1990. The primary reason for the high DOE numbers is that the DOE model considerably understates transportation costs from southern Wyoming because distances in the model are calculated using a centroid located in the Powder River basin, In 1990, DOE's low forecast is still higher than ICF's high forecast (for the reason just mentioned) and the OTA range of likely to likely high production falls within the midrange to upper range of the ICF forecast. For reasons that are not clear, the ICF base forecast drops below its 1985 forecast (from 38 million to 36 million tons) and is thus lower than the OTA task force projection.

Colorado

The DOE and ICF forecasts for 1985 are very close (36 million and 35 million tons respectively); the OTA task force estimate in this case is an estimate of minimum demand. For 1990, the OTA task force estimate of 32 million to 38 million tons is comparable to the ICF and DOE low forecasts, The ICF base forecast is considerably higher than the DOE

DOE and ICF forecasts shown in table 31, These ranges are indicative of the sensitivity of demand to changes in assumptions that are plugged into the model, but are not necessarily indicative of what is likely to happen in the real world. Even though the low to high ranges identified by OTA for analysis of existing Federal leases are narrower than the model ranges, it is likely that demand for 1985 and 1990 will be within the range. After 1990 uncertainties and ranges in forecasts increase considerably (see final section of this chapter]; OTA did not attempt to develop most likely ranges of demand for the post-1990 period.

Figure 21.—Demand Projections for the Fort Union and Powder River Coal Regions and Southern Wyoming, Compared to OTA Task Force Estimates



[a]No OTA protection

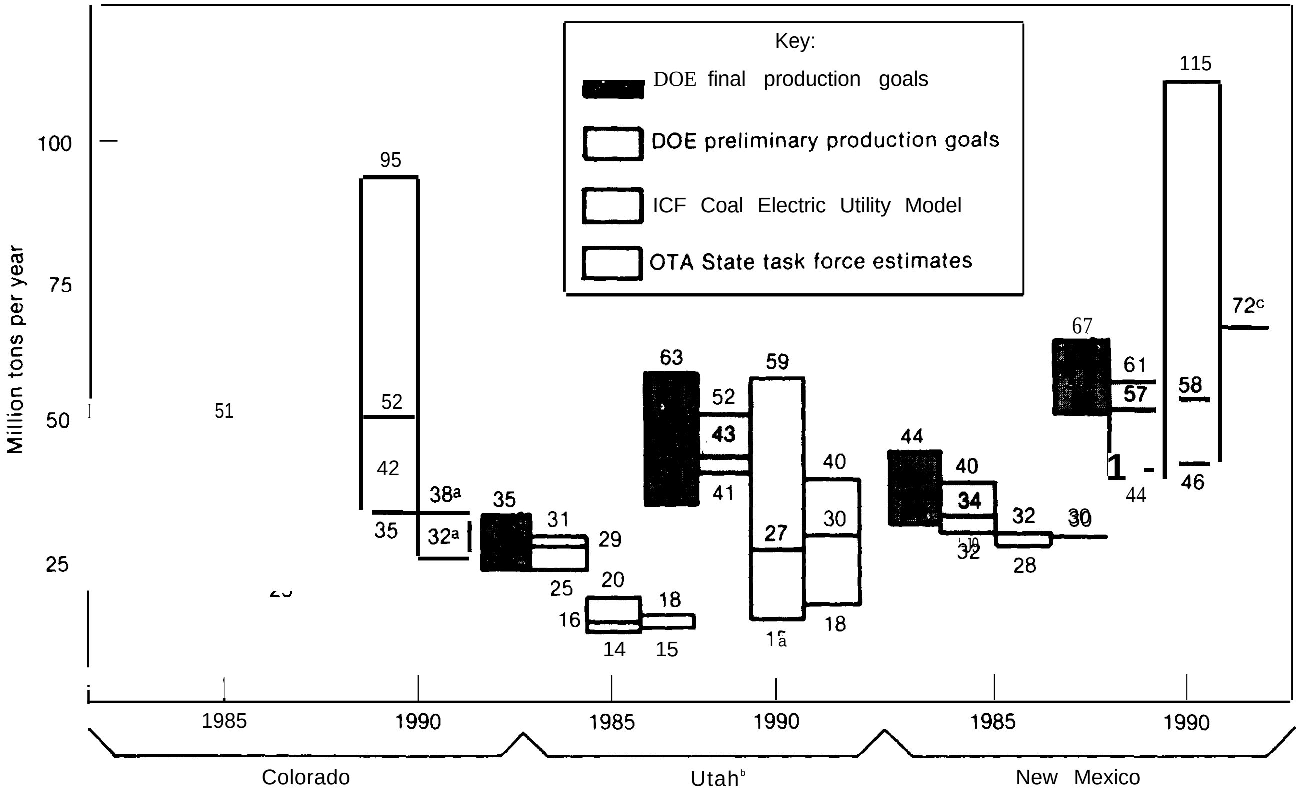
SOURCE Table 30

medium forecast (52 million v. 42 million tons). The OTA task force estimate was conservative; and although the DOE and ICF models may not be sensitive to the especially disadvantageous situation in Colorado with respect to transportation costs, as discussed earlier in this chapter, demand in 1990 may be closer to the DOE range than the OTA range.

Utah

The forecasted ranges by DOE and ICF do not overlap at all in 1985. The OTA task force estimated that 1985 production in Utah would come from mines currently in operation or construction. In 1980, the State geological survey estimated planned 1985 production would be between 15 million to 18 million tons. Probably the ICF base of 16 million tons and the DOE medium forecast of 29 million tons is a reasonable low to high range. In 1990 the ICF base projection and OTA mis-estimate are close (27 million and 30 million tons respectively) but are considerably lower than the DOE midrange forecast of 43 million tons. The DOE medium forecast is quite close to the OTA high estimate of 40 million tons.

Figure 22.—Demand Projections for Colorado, Utah, and New Mexico, Compared to OTA Task Force Estimates



[a]Figures shown are low ranges.
[b]OTA demand estimates for-central Utah only
[c]Figure represents maximum likely demand.

SOURCE Table 30

New Mexico

The ICF base forecast and the OTA estimate in 1985 are exactly the same (30 million tons) and 4 million tons lower than the DOE forecast, which indicates good agreement among all three forecasts. In 1990 the DOE and ICF forecasts are very close (57 million and 58 million tons respectively) but are considerably lower than the OTA task force estimate of 72 million tons. The OTA task force estimate was admittedly an optimistic estimate, and assumed that in the 1990's New Mexico would be shipping 20 or more million tons of coal to Texas markets. A substantial portion of Texas exports would come from captive mines. The OTA task force estimate has been categorized in table 31 as a potential high production level rather than a "most likely" level of production. If it is assumed that New Mexico exports a more modest level of 10 million tons per year to the South-Central States in 1990, the OTA estimate would drop to 62 million tons, which is close to the DOE and ICF projections.

Comparisons of Forecasts

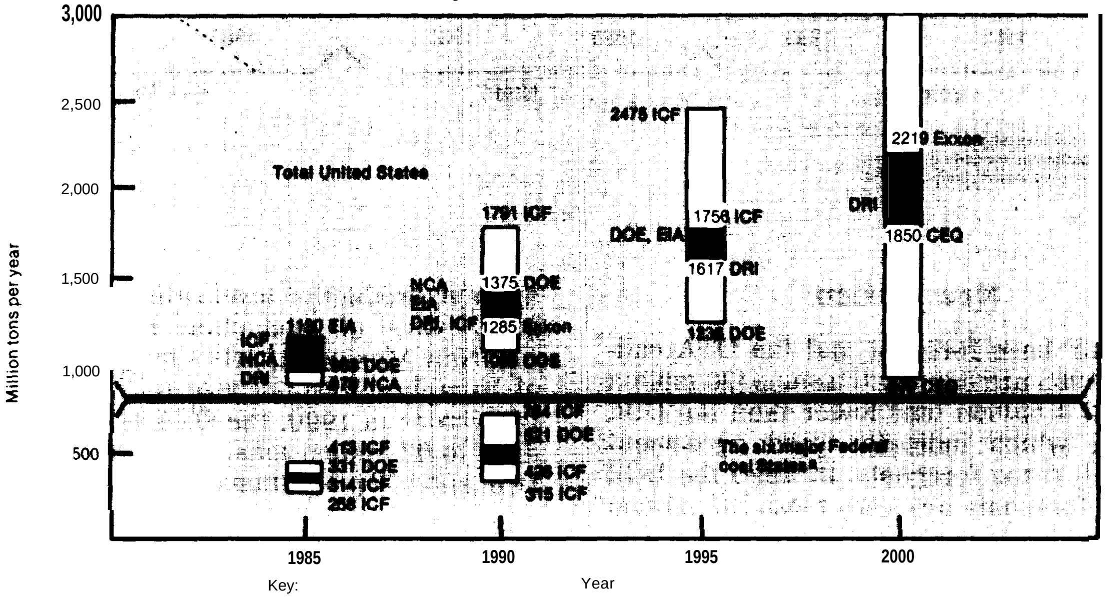
The comparisons between the three sets of forecasts for the major Federal coal regions and States allow a few generalizations. First, compared to the DOE and ICF forecasts, the OTA task force estimates are quite consistently lower than, or near the lower of the mid-range forecasts of the two models. Although the specific reasons for this vary, this is probably generally because the OTA task force estimates are more sensitive to some of the factors discussed earlier in this chapter that have weakened the competitive position of Western coal. Another reason is that the OTA task forces quite uniformly did not consider synthetic fuels or foreign exports to be significant sources of demand before 1990. Should demand from these sources materialize to a greater extent than expected by the task forces, demand might be higher than the "most likely" levels estimated. However, inclusion of the higher midlevel forecasts from other sources increases the upper range of the "most likely" estimates sufficiently that possible demand from these sources is likely to be adequately accounted for. A second generalization is that the 1990 forecasts from all sources tend to have wider ranges than the 1985 forecasts. This can be attributed to the higher levels of uncertainty in the factors affecting demand 10 years from now compared to 5 years from now.

Demand for Western Coal: 1990=2000

Forecasts for the demand for Western coal after 1990 have a much higher level of uncertainty than the period from 1980 to 1990, and OTA has not tried to conduct any quantitative analysis for the 1990's. However, a number of demand forecasts are available for the United States through 2000, and these can be used to get a general idea of possible trends and development through to the end of this century.

Table 32 shows eight forecasts made in the last few years for total U.S. coal production in 1985, 1990, 1995, and 2000. Elements of these forecasts are compared schematically in figure 23. Also shown in figure 23 for 1985

Figure 23.– Demand and Production Forecasts for the United States: 1985-2000 and the Six Major Federal Coal States:[a] 1985-90



CEQ Council on Environmental Quality
DRI Data Resources, Inc.
DOE Dept. of Energy National Coal Model[c]
EIA Energy Information Administration
ICF ICF Coal Electric Utility Model
NCA National Coal Association

[a]Colorado, **Montana. New Mexico, North Dakota, Utah, and Wyoming**
[b]Intermediate high and low forecasts **from the various sources not shown.**
[c]**DOE's 19S0 preliminary production goals are shown here rather than the final goals because they are more comparable with other production forecasts See discussion p 100**

SOURCE Table 32.

and 1990 are the DOE and ICF forecasts for the six major Federal coal States combined. From 1990 to 2000 both the range of "most likely" forecasts in figure 23 (shaded) and the range of low to high increase greatly, reflecting the greater uncertainties inherent in forecasting over longer periods of time. In fact the low forecast in 2000 (899 million tons) made by the Council on Environmental Quality (CEQ), is lower than the lowest medium projection in 1985 (963 million tons by DOE) (see table 32). The CEQ forecast is based on a low-energy growth scenario in which conservation is the main focus of national energy policy.

Electrical growth rates after 1990 are generally projected to be similar to or lower than growth projected for the 1980-90 decade. For example, Exxon's projection of 5.3 percent from 1978 to 1990 drops to 2,9 percent from 1990 to 2000. ICF projects electrical growth rate continuing at 3.0 percent from 1990 to 1995. Consequently, according to these projections of electrical growth rate, rates of increase in coal demand for utility use can be expected to be somewhat lower or about the same in the last decade of this century, although conversion of oil and gas to coal may offset lower overall electrical growth rates.

Significant areas of potential new demand for western coal after 1990 include: 1) synthetic fuels, 2) industrial boilers, and 3) foreign export. Possible (but not necessarily probable) levels of demand for Western coal for these uses after 1990 could total on the order of 250 million tons, which is more than the total of 231 million tons produced in the West in 1979. Coal consumption for synthetic fuels plants could be around 100 million tons (see p. 100), Incremental demand for industrial boilers from 1990 to 2000 in the whole United States could be on the order of 100 million tons (assuming the 7-percent growth in demand projected by NCA from 1979 to 1990 continues) of which perhaps half might be supplied by the West, Foreign exports could possibly range from 50 million to 100 million tons,

Most of the projections shown in table 32 are not disaggregated to a level that allows a close look at trends in forecasted production from the six major Federal coal States, but most forecasts make a breakdown between production from the West and East. Some trends are evident when Western coal production is translated into percentage of total U.S. coal production (see table 33). All the forecasts show a steady increase in the West's share of total U.S. coal production between 1985 and 2000. A significant part of this increase is due to the fact that more Western coal must be mined to make an equivalent contribution to U.S. energy needs compared to Eastern coal. For example, the CEQ forecast did not take this into account, and adjusting their forecast to correct for the lower heat content of Western coal increased CEQ's low coal demand scenario in 2000 from 782 million to 899 million tons (see footnote, table 32).

A comparison of the different forecasts for any given year in table 33 shows that there is a considerable range in the percentage that is projected to come from the West. In 1985 the West's share of total U.S. production is projected to range from 33 to 43 percent and in 1990 from 38 to 49 percent. The Energy Information Administration production forecasts, which are the lowest for these 2 years agree with the most recent forecast in table 33 made by NCA and it seems likely that the growth rate of Western coal production will increase at a lower rate than the various model forecasts (DOE, ICF, and DRI) indicate. In 1995 the forecasted percentage of Western coal production begins to converge (from 47 to 52 percent) with a mid point of 49.5 percent and in 2000 Western coal production is projected to exceed so percent of U.S. production.

In table 33 the numbers in parentheses indicate the percentage of total U.S. coal production that would come from the six major Federal coal States. It is clear from these percentages that these States account for most of the production from the West, but the DOE and ICF forecasts show production from

Table 33.—Forecasted Changes in Contribution of Western Coal to Total U.S. Production

	Western coal production as percent of total United States[a]			
	1985	1990	1995	2000
EIA production forecasts (1979) . .	33	38	47	—
Exxon (1979)	—	45	—	53
DOE production goals (1980)	40(34)[b]	46(38)	49(39)	—
ICF CEUM forecasts (1980)	38(30)	44(33)	50(38)	—
Data Resources, Inc. (1980)	41(34)	49(41)	52(44)	55(46)
National Coal Association (1981) .	34	38	—	—
DOE final production goals (1981)	43(32)	47(32)	52(36)	—

[a]Western coal includes all production west of the Mississippi River. In addition to the six major Federal coal States, Western production includes coal mined in the Western Interior coal province, the Gulf Coast lignite province, Arizona, Washington, and Alaska. In 1979, Western coal production was 28 percent of total U.S. production and production from the six major Federal coal States was 21 percent of total production.

[b]Number in parentheses is production from the six major Federal coal States (Colorado, Montana, New Mexico, North Dakota, Utah, and Wyoming) as a percentage of total U.S. production.

SOURCE. See table 32

the major Federal coal States growing at a somewhat slower rate than total Western coal production between 1985 and 1995. The DRI forecast shows production from the major Federal coal States growing at a slightly faster rate than total Western coal production between 1985 and 1995. It is interesting to note that the final DOE production goals indicate a relatively smaller proportion of production from the major Federal coal States compared to the preliminary goals (i.e., 32 v. 38 percent in 1990). The final goals are considerably higher than the preliminary goals, but the assumed higher cost increases in transportation appear to have restricted the share that the Federal coal States obtain of the higher goals.

Summary

The analysis of the various factors affecting demand for coal from the major Federal coal States in this chapter allows a few general conclusions:

1. The demand for coal from the major Federal coal States will continue to grow at a faster rate than the total growth in the demand for coal in the United States due primarily to the low cost of mining this coal compared to the Midwest and Appalachia, and to the fact that more coal must be mined to meet equivalent energy needs because of the lower heat content of the coal.
2. However, because of several factors (increasing transportation costs and present SO_2 emission standards being among the most important) the competitive position of Western coal in the Midwest and South-Central United States (which are the major centers of demand for Western coal) will not be as favorable during the next 10 years. as compared to the previous 10 years. The net effect of these factors, combined with downward revisions in projected growth rates for electricity means that the growth in demand for Western coal will probably not be as great as some earlier forecasts had predicted.
3. After 1990 Western coal is expected to continue increasing its share of total U.S. coal production, but total Western coal production may increase at a slightly faster rate than coal production from the major Federal coal States. Offsetting slowed growth in demand because of possible reduced electrical growth are a number of possible new markets for Western coal for which precise demands are difficult to predict, but which could potentially be large consumers of coal. These potential major new markets for Western coal after 1990 are synthetic fuels, industrial boiler conversions, and exports to Asia.