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Challenges of Electric Power Industry Restructuring for Fuel Suppliers

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Preface

Section 205(A)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data and information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information.

The purpose of this report, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, is to provide an assessment of the changes in other energy industries that could occur as the result of restructuring in the electric power industry. This report is prepared for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

The legislation that created the EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions. The EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decisionmakers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

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Executive Summary

The current movement to restructure U.S. electricity generation markets and make them more competitive may lead to changes in the financial risks and demands on the supply and transportation infrastructures for the fuels used in electricity generation. This report examines the potential impacts of restructuring of the U.S. electric power industry on the markets for electricity generation fuels—coal, nuclear, natural gas, petroleum, and renewable energy.

Included in this report are a brief review of electric power industry restructuring already in progress at the Federal and State levels, detailed discussions of the major qualitative issues for each of the major fuel supply markets, and a presentation of a range of possible quantitative results, based on the Energy Information Administration's (EIA) National Energy Modeling System (NEMS).

The following paragraphs summarize the discussions of issues related to the markets for coal, nuclear, natural gas, petroleum, and renewable fuels, followed by the quantitative analysis of electric power industry restructuring on fuel markets.

Coal

The U.S. coal and electric power industries are tightly linked: more than 87 percent of total domestic coal consumption is used for generation by utilities, and coal accounts for more than 56 percent of utility power generation. Thus, competitive electricity generation markets will have far-reaching implications for the coal industry. Power generators will attempt to pass on market risks to coal producers and carriers (primarily railroads) wherever they can. As a result, coal purchase contracts will likely become shorter in duration and lower in price. The traditionally stable coal market may absorb some of the volatility of electricity markets.

Electric power industry restructuring is expected to result in renewed pressure for cost cutting and consolidation in the coal industry, extending the trend of the past decade or more. Future gains in productivity will result from the computerization of administrative tasks and continuing improvements in production technology. Taking advantage of economic returns to scale will be another important component of the cost reduction effort. Small firms may be forced out of business, and large firms are likely to continue increasing in size through acquisitions and mergers. In addition, the trend toward shorter contract durations and an uncertain customer base will lead financial institutions to evaluate coal mines on a "balance sheet" basis rather than on the traditional project financing basis, increasing the pressure for industry consolidation.

Risk management will become an important new tool for coal producers. Coal futures markets, already being developed in some areas, will provide a mechanism for risk hedging and for price discovery. Risk reduction may also be accomplished by vertical integration, alliances with railroads or power producers, or the creation of multi-fuel conglomerates. Restructuring will change the business relationships among coal producers, railroads, and power generators, creating incentives for new alliances and the convergence of energy markets.

Emerging changes in the structure of the railroad industry may also affect the economics of both the coal and electric power industries. Transportation costs are a major component of the delivered price of coal to electricity generators, and over half of all coal consumed by them is delivered by rail. As the demand for low-sulfur western coal increases in the coming years, the importance of railroads will become even greater. The full effect on rail rates of the recent and ongoing consolidation of major railroads remains to be seen: the railroads may continue to lower rates as they achieve greater economies of scale, or they may be unwilling to lower rates once they establish their market power, as many coal shippers are concerned will be the case.

Nuclear Power

Nuclear power accounts for about 13 percent of current U.S. electricity generating capacity and about 19 percent of total electricity generation. As the States restructure electricity markets over the next few years, however, some nuclear power plants are expected to become uneconomical. Competitive electricity prices may be so low that nuclear power plant operators will not see

enough income to enable them to recover the costs of operating and maintaining the plants and the costs of capital improvements, such as steam generator replacements. In the immediate future, some nuclear power units will be at risk of early retirement as a result of restructuring.

The additional inability of plant operators to cover a plant's full costs, including capital costs, under restructuring produces "stranded costs." The stranded cost recovery issue will not, however, be the major factor in retirement decisions. Ultimately, the long-term viability of nuclear power generation lies in the industry's ability to keep its operating costs competitive with new sources of generation. For nuclear plants, operating costs after deregulation will be driven mainly by plant size, age, capacity factors, and requirements for new capital improvements. Issues surrounding the recovery of future decommissioning costs remain to be resolved. In the long run, however, the market value for long-term firm capacity and for electricity in each region of the country will determine the value of nuclear power plants.

Average fuel costs make up only about one-fourth of the operating costs for nuclear power plants, but the competitive environment created by a restructured electric power industry will encourage nuclear power plant operators to reduce all operating costs, including the costs of purchasing and managing nuclear fuel. Moreover, if early retirements of nuclear power plants result from competition in electricity markets, the demand for nuclear fuel will be reduced. To compete, suppliers in the nuclear fuel industry will be forced to reduce prices or improve efficiency. In an industry that has already seen significant contraction during a decade of depressed prices, further consolidation is likely as companies seek to pool resources and spread risks.

Natural Gas

Natural gas, used for about 9 percent of electric utility generation, is primarily used during peak demand periods and is the preferred energy source for new generating capacity. The electric power and natural gas industries are both network industries, in which energy sources are connected to energy users through transmission and distribution networks. As the restructuring of electricity markets proceeds, the development of institutions, such as futures contract markets and electronic auction markets, could lead to greater integration of the electricity and natural gas industries and the emergence of competitive energy markets.

The availability of market information and public markets for natural gas and electricity will be a key to the development of an integrated energy market for those commodities. Price volatility for gas and electricity will spur the growth of futures markets and promote the efficient allocation of resources. Challenges for the natural gas industry include the development of shorter term contracts with standard terms and low transaction costs, improvements in deliverability and flexibility, and the synchronization of same-day nominations for deliveries of gas and electricity. Metering and measuring of gas flows throughout the industry are also likely to become more important as more frequent exchanges of energy take place among market participants.

Oil

Restructuring of the U.S. electric power industry should have little overall impact on crude-oil-derived fuels (distillate and residual). In 1996, for example, petroleum, which fueled 2.2 percent of electric utility generation, accounted for only 2.3 percent of the Nation's petroleum consumption. With the deregulation of electricity generation and the resulting incentive for power generators to lower fuel costs, the use of relatively expensive residual fuel oil for electricity production is likely to decline even further. As a result, petroleum refiners may be faced with a growing problem: how to dispose of "leftover" residual fuel and petroleum coke. Among other options, two possibilities are related to electricity markets: (1) selling petroleum coke to electricity generators for use as a fuel blending component, and (2) gasification at the refinery by using integrated gasification combined-cycle (IGCC) technology to produce steam for process heat and for electricity production.

Finally, electricity deregulation may provide oil companies with opportunities to expand synergistically into a related business. A number of oil companies have gained experience in electricity production as a means of exploiting their natural gas holdings in other countries, and they could become important players in the U.S. market as capacity needs grow in the future. Meanwhile, as economic considerations increasingly dictate when distillate fuel oil (and other fuels) will be purchased and at what price, electricity generators will be relieving the pressure on both available supply and the marginal price in the very volatile heating oil market that characterizes the Northeast during severe cold snaps.

Renewables

Because electricity generation from renewable sources (other than hydropower) generally is more expensive

than power from conventional sources, unconstrained competition in electricity generation would likely result in a reduced role for renewable energy facilities. As a result, a variety of proposals under consideration by State legislatures and by the U.S. Congress include specific provisions to support the continued development and use of renewable energy. Renewable portfolio standards and system benefits charges are among the programs being considered. Green marketing and pricing programs, already being implemented by electric utilities, may also provide a means to increase consumer demand for electricity from renewable fuels.

The role of renewable energy sources in competitive electricity markets will also depend on the cost and performance of the individual renewable fuels: biomass (primarily wood), geothermal, solar, and wind. In addition, because renewable energy generating facilities generally depend on the availability of energy resources at specific sites—often at sites remote from major electricity grids—transmission issues will affect the penetration of renewable fuels in the electricity generation market.

Quantitative Impacts on Fuel Markets

A quantitative analysis was conducted to determine the impacts that competitive electricity generation markets could have on fuel supply industries. To capture the uncertainty about the conditions under which a competitive electricity market will operate, EIA prepared a range of possible outcomes (i.e., analysis cases) based on different assumptions about key electricity and energy variables. Two full competition cases (assuming low and high fossil fuel consumption), in addition to a partial competition case (the reference case from EIA's *Annual Energy Outlook 1998* (*AEO*)), were compared with a no competition case in order to illustrate the possible impacts of competition.

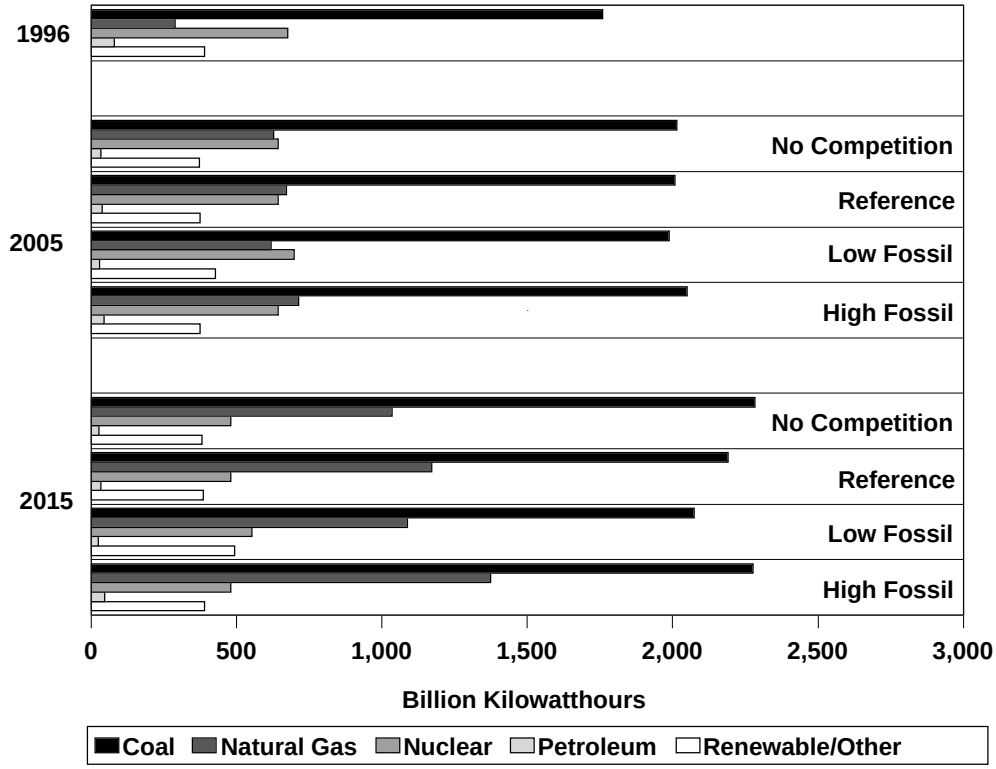
In all the cases, natural-gas-fired turbines and combined-cycle plants garner most of the market for new generating capacity when more competition was assumed. From 1996 to 2015, additions of coal-fired capacity are projected to range from about 20 gigawatts in the low fossil fuel case to 49 gigawatts in the no competition case, whereas additions of natural gas turbine and combined-cycle capacity range from about 256 gigawatts in the no competition case to 324 gigawatts in the high fossil fuel case. In all the cases, natural gas is projected to have an increasing share of electricity generation as demand levels grow (Figure ES1).

Unless required by Federal policies, the restructured electricity market is not projected to stimulate renewable energy technologies. Overall, the cases analyzed suggest that renewable resources will remain more costly than fossil fuel alternatives through 2015 and will penetrate electricity markets only to the extent compelled, such as by a renewable portfolio standard that mandates generation from renewable sources. If policies require increased use of renewable energy, the cases suggest that average electricity prices will increase slightly. Biomass, wind, and geothermal would be the most likely technology choices for expanded use of renewable energy.

In the competition cases examined, natural gas production is projected to range from 0.8 percent lower to 2.2 percent higher than in the no competition case in 2005 and from 0.3 percent to 6.0 percent higher in 2015. The projected average natural gas prices at the wellhead range from a low of $2.05 per thousand cubic feet in 2005 to a high of $2.61 per thousand cubic feet in 2015 (all prices expressed in real 1996 dollars). Overall, the results from all the cases suggest that restructuring in the electric power industry will stimulate demand for natural gas and that rising demand will lead to higher wellhead prices as the discovery process progresses from larger and more profitable fields to smaller, less economical ones. The projected price increases also reflect more production from higher-cost sources, such as offshore conventional recovery and onshore unconventional gas recovery from such sources as tight sands, Devonian shales, and coalbed methane. Electricity restructuring is not expected to have a significant impact on crude oil production because petroleum-based generation is a small share of overall electricity generation.

In the national coal market, two factors lead to significant changes: (1) the environmental regulations creating a national market for sulfur emissions credits, which encourages minimization of sulfur emissions and, thus, fuel sulfur content; and (2) the competitive electricity generation market, which rewards the minimization of generation fuel costs. The impacts of both changes are seen in the cases analyzed here. Across the cases, competition tends to favor the use of natural gas over coal for electricity generation because natural-gas-fired power plants are generally projected to be more economical than coal-fired plants. The exception is the high fossil case, which assumes higher demand for electricity than in the *AEO* reference case, no renewable portfolio standard, and continued operation of relatively higher-cost generating plants (up to 6 cents per

Figure ES1. Electricity Generation by Fuel Type in Four Cases, 1996, 2005, and 2015



Note: Data do not include nonutility generation for own use, cogeneration, or electricity imports. Renewable/other includes pumped storage hydroelectric.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

kilowatthour). The cases vary in their projections of consumption shares for low-, medium-, and high-sulfur coals, regional production shares, and minemouth prices. Production of high-sulfur coal is relatively stable across the competition cases and declines by about 19 million tons in the low fossil case in 2010. In contrast, low-sulfur coal production is more volatile and increases by as much as 80 million tons in 2015 in the high fossil case due to increased demand for coal while requirements to limit sulfur dioxide emissions are tightening.

Total energy consumption for electricity generation is projected to grow from 1996 to 2015 in all the cases analyzed. Consumption levels increase for all fossil fuels and renewable sources, whereas consumption of nuclear electricity generation declines as a result of retirements and the lack of new construction. There is little variation in total energy consumption among the competition cases, except when higher demand levels are assumed. There are, however, variations in the levels of consumption of natural gas and coal across the cases, with natural gas tending to gain and coal to lose market share as the industry moves from a regulated to a competitive environment.

The average price of fuel used for electricity production in 2015 is projected to be about the same as in 1996 in all but the high fossil case (Table ES1). In the high fossil case, an increase of about 11 percent in the average price is projected because of higher natural gas prices resulting from assumed higher drilling costs for onshore production. Natural gas prices increase slightly in the other cases but are offset by an almost 30-percent decline in coal prices between 1996 and 2015.

Electricity prices are projected to decline from 1996 levels, even in the case of no competition, because of lower coal prices and modest additions of new capacity. In the competition cases, prices fall even further as a result of efficiency improvements in plant operations and fewer additions of capital-intensive coal plants. Prices in competitive markets are based on marginal costs, which tend to be lower than the current average embedded costs.

Table ES1. Energy Consumption and Prices for Electricity Generation

Projection	1996	2005				2015			
		No Competition	*AEO98* Reference	Low Fossil	High Fossil	No Competition	*AEO98* Reference	Low Fossil	High Fossil
Energy Consumption by Electricity Generators (Quadrillion Btu per Year)									
Distillate Fuel	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.09
Residual Fuel	0.67	0.28	0.30	0.22	0.36	0.20	0.25	0.16	0.37
Petroleum Subtotal	0.75	0.34	0.37	0.28	0.44	0.27	0.32	0.23	0.46
Natural Gas	3.04	5.39	5.69	5.23	6.01	7.98	8.71	8.02	10.06
Steam Coal	18.36	20.60	20.55	20.35	21.04	23.16	22.29	21.21	23.21
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	4.45	4.37	4.37	5.06	4.31	4.44	4.53	6.25	4.59
Electricity Imports	0.39	0.39	0.34	0.37	0.37	0.28	0.28	0.30	0.30
Total	34.20	37.96	38.19	38.75	39.03	41.25	41.26	41.91	43.75
Energy Prices to Electricity Generators by Source (1996 Dollars per Million Btu)									
Fossil Fuel Average	1.54	1.46	1.49	1.44	1.51	1.49	1.60	1.51	1.71
Petroleum Products	3.27	3.61	3.57	3.76	3.46	4.13	4.00	4.27	3.77
Distillate Fuel	4.90	5.17	5.16	5.15	5.14	5.45	5.47	5.42	5.40
Residual Fuel	3.07	3.23	3.20	3.34	3.09	3.67	3.60	3.79	3.36
Natural Gas	2.64	2.58	2.63	2.56	2.72	2.80	2.98	2.85	3.32
Steam Coal	1.29	1.14	1.14	1.11	1.13	1.01	1.03	0.97	0.97

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Introduction

The movement toward a competitive electricity generation market has been underway for several years. Many consumers, producers, and regulators see increased competition as a key to more efficient production of power and lower end-use prices. With the electric power industry accounting for more than $210 billion in annual sales, the implications of deregulated electricity generation markets for capacity choice, operating costs, and fuel choice are significant. This report examines potential impacts of restructuring and deregulation of the electric power industry on the markets for electricity generation fuels—coal, nuclear, natural gas, petroleum, and renewable fuels.[1]

The U.S. electric power industry is in the midst of a transition that is changing electricity generation operations from regulated monopolies to entities that operate in competitive markets. As the transition progresses, the competitive pressure for lower electricity prices could alter the Nation's power generation fuel mix. The possible ramifications vary in likelihood and complexity. Generating companies may change their fuel purchase arrangements and inventory practices. Higher cost generating plants may be retired in favor of more efficient, low-cost power plant technologies, and the shares of electricity generation from different fuels may change. (For example, legislation may be enacted to ensure some level of market share for renewable fuels in the generation mix.)

Electric power industry restructuring may lead to new financial risks and demands on the supply and transportation infrastructure of the fuels used for electricity generation. This report analyzes issues that electricity restructuring creates for each fuel market.

Major Restructuring Changes Already in Progress

Numerous structural changes in the electric power industry are yet to come. Already, however, there has been significant progress by regulators, legislators, and the utilities themselves toward a competitive electricity market.

FERC Actions

Perhaps the single most sweeping change so far has been the outcome of recent actions taken by the Federal Energy Regulatory Commission (FERC), which has the responsibility for regulating the Nation's interstate trade in electric power. Pursuant to guidelines set forth in the Energy Policy Act of 1992 (EPACT) regarding open access to transmission services at equitable rates, the FERC issued Orders 888 and 889 in 1996. These orders were designed to remove impediments to competition in wholesale electricity trade and are expected to bring more efficient, lower cost power to the Nation's electricity consumers. On February 26, 1997, in response to various rehearing requests, the FERC announced a number of minor adjustments to the rules, to become effective 60 days after they appeared in the *Federal Register*.[2]

Order No. 888, entitled *Promoting Wholesale Competition Through Open Access Nondiscriminatory Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, requires all public utilities that own, control, or operate transmission facilities to provide nondiscriminatory open access transmission

[1] Renewable fuels are hydroelectric (conventional), geothermal energy, biomass (wood, wood waste, peat, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and / or other waste), solar energy (solar thermal and photovoltaic), and wind energy.

[2] For further details concerning FERC actions regarding electric power industry regulatory reform, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE-EIA-0562(96) (Washington, DC, December 1996), Chapter 7. In addition, EIA has recently published a report entitled *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, that updates information on restructuring activities by the FERC, Congress, and the States.

services by filing tariffs that offer others the same transmission services they provide to themselves. In addition, it provides for a stranded cost mechanism to aid in the transition to a more competitive industry. Stranded costs are those that utilities prudently incurred to serve customers under a regulated environment, which could go unrecovered if customers switch to other suppliers. The FERC stressed that providing for stranded cost recovery would ensure the financial viability of utilities that provide reliable, essential electric service.

Order No. 889, *Open Access Same-Time Information System and Standards of Conduct (OASIS)*, further ensures nondiscriminatory transmission service by requiring public utilities that own, control, or operate transmission facilities to develop an Internet-based bulletin board system that provides same-time information about electricity prices and the availability of transportation capacity on transmission lines. This rule requires public utilities to obtain information about their transmission system for their own wholesale power transactions in the same way their competitors do—through the Internet OASIS system, which began commercial operation in January 1997. It also requires them to separate their functions of wholesale power marketing and transmission operation.

As a result of the FERC Orders, many investor-owned utilities that own transmission lines have begun to establish independent system operators (ISOs) to manage and operate the transmission systems in their regions. Eleven ISOs have been approved, proposed, or are under discussion, covering all parts of the United States except the Southeast. Utility participation is fragmented, however, and issues have arisen regarding participation by Federal and other publicly owned utilities. As of April 1998, four ISOs were operating: California ISO; ISO-New England; Pennsylvania, New Jersey, Maryland Interconnection; and the ERCOT ISO. Each has procedures for pricing transmission services—in particular, when congestion occurs in the transmission system. It is too early to determine what, if any, changes may be seen in generation patterns and fuel consumption as a result.

Congressional Actions

While no Federal legislation that applies directly to electric power industry restructuring has been enacted, a number of bills have been introduced in recent years, and Congress has been actively pursuing the matter (see Appendix A). Electricity workshops and Congressional Committee hearings have been and are being held to investigate the issues and impacts and to hear industry views on the role the Federal Government should play in restructuring the industry. Restructuring legislation was introduced but not passed during the 104th Congress. Revised legislative proposals have been introduced and are being debated in the hopes of mandating a federally guided approach to restructuring before the end of the 105th Congress. On June 26, 1998, the Secretary of Energy submitted to Congress the Administration's proposed legislation to implement the Comprehensive Electricity Competition Plan that was released by the Administration on March 25, 1998.

The common theme among the proposals is to set forth guidelines that will benefit and protect electricity consumers by giving them the right to choose among competitive suppliers while securing lower rates and higher quality service. Some proposals encourage energy conservation and efficiency programs and the use of renewable sources of energy. One bill that contains the most proactive measures concerning renewables, H.R. 1359 introduced by Congressman Peter A. De Fazio (D-OR), instructs the Secretary of Energy to establish a National Electric System Public Benefits Board to fund programs related to renewable energy sources, universal electric service, affordable electric service, energy conservation and efficiency, or research and development in each of these areas. The bill also provides for a renewable energy portfolio standard and for renewable energy credits. Two bills set forth a date certain for retail competition. H.R. 655, the Electric Consumers' Power to Choose Act of 1997, introduced by Congressman Dan Schaefer (R-CO), specifies December 15, 2000; and S. 237, the Electric Consumers' Protection Act of 1997, introduced by Senator Dale Bumpers (D-AR), specifies December 15, 2003, as the date by which all retail customers will be able to choose their electricity providers.

Also included in the Federal proposals are bills to repeal the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Public Utility Holding Company Act of 1935 (PUHCA), both of which are being identified as impediments to a truly market-driven electric power industry. Some groups believe that PURPA and PUHCA repeal should be instituted, but only as part of legislation that would comprehensively address the many issues associated with restructuring. Additional issues—including privatization of the Federal Power Marketing Administrations, Federal Power Act amendments prescribing State parameters relative to instituting retail competition, the recovery of stranded costs, and the role that the Federal Government should play in restructuring the electric power industry—are addressed in various bills.

Appendix A summarizes pending Federal legislation and the Administration's plan[3] for the restructuring of the electric power industry, including an overview of the major issues contained in each.

State Actions

Retail competition is being deliberated on a State-by-State basis. The utility regulatory commissions and the legislatures of nearly all 50 States and the District of Columbia are in different stages of the implementation process, from informally studying the idea to passing legislation that specifies the date and conditions of full retail competition. In order for a State to make the transition to a fully competitive market, its legislature must first pass legislation that authorizes the conversion to deregulation. Only then can the State regulatory commission proceed with approved implementation plans. Six States, however, have been able to initiate competition through regulatory orders only. Figure 1 shows the progress being made throughout the United States toward establishing full retail competition. As of July 1, 1998, 12 States had enacted restructuring legislation.

On March 31, 1998, California became the first State to open its retail electricity market to competition. Retail access pilot programs are also underway in a number of States, including Idaho, Illinois, Massachusetts, Michigan, Missouri, Montana, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, Texas, and Washington. While there are similarities among them, each pilot program contains specifications (regarding size and duration, flexibility, billing and metering, targeted customers, etc.) that vary from one program to another.[4] Pilot programs are being instituted to provide insights into the workings of retail access. The lessons learned will serve as the building blocks for full retail competition.

Also being examined by those involved in formulating retail competition guidelines are Federal and State jurisdictional issues. Some groups believe that, while States may be in a position to direct certain aspects of full retail competition, the Federal Government is in the best position to address broader aspects, such as the environment, rules of reciprocity, and a date certain for customer choice. The rules of the game have been and will continue to be redefined by Federal and State regulators and legislators.

Some of these issues are discussed in more detail in two other Energy Information Administration reports, *The Changing Structure of the Electric Power Industry: An Update* and the recently released *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*.

The Role of Fuel Markets in Electricity Generation

More than one-third of the primary energy consumed in the United States is used to generate electricity. In 1996, the Nation produced 3,447 billion kilowatthours of electric power. Of that amount, utilities accounted for 3,077 billion kilowatthours and nonutilities generated the remaining 370 billion kilowatthours.[5] Coal-fired generation has been and continues to be the largest contributor to the supply of electricity, followed by nuclear, natural gas, renewables, and petroleum. In 1996, utility purchases accounted for 87 percent of the U.S. coal market, 53 percent of the renewables market, 12 percent of the natural gas market, 2 percent of the oil market, and virtually all the uranium available in the commercial market.[6] Investor-owned utilities spent approximately $22.8 billion on coal in 1996, $7.4 billion on natural gas, $3.0 billion on nuclear fuels, and $2.4 billion on petroleum.[7] Because fuel costs account for two-thirds of utility power production expenditures,[8] the future price of fuels is a critical issue for utilities facing the change to a competitive market.

Since 1986, there has been a downward trend in fuel costs. In the coal industry, increased productivity, lower transportation rates, and changing market conditions have produced a steady decline in coal prices. Average prices for natural gas to electric utilities have generally

[3] U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 1998).

[4] Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE/EIA-0620 (Washington, DC, May 1998), Chapter 4.

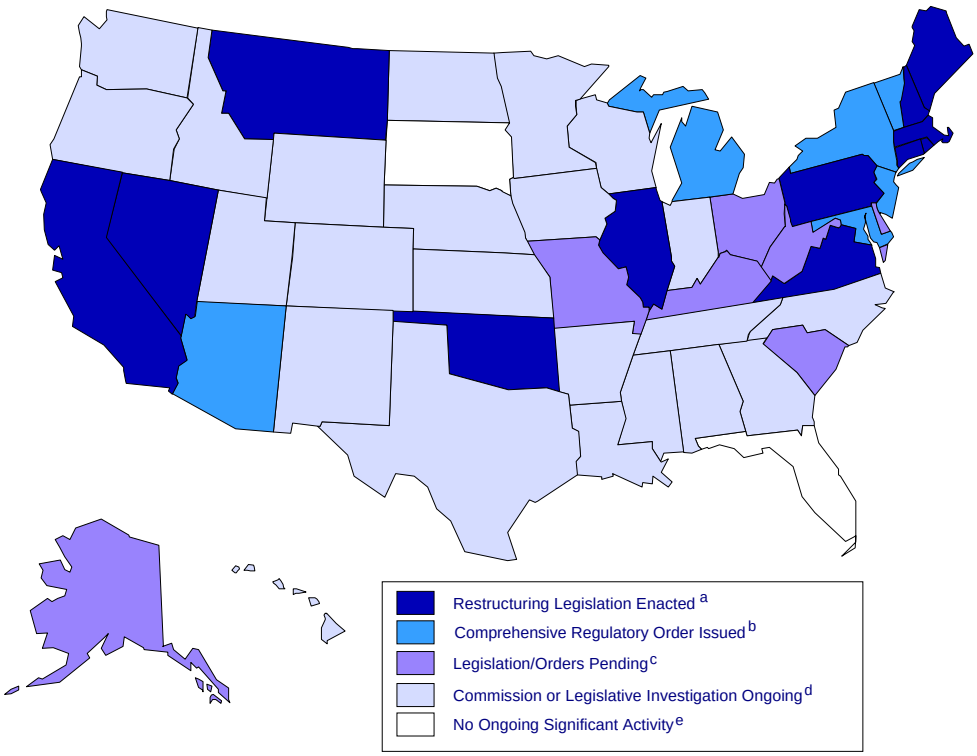
[5] Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997), pp. 13-14.

[6] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), pp. 211, 265, 195, 161, and 259, respectively.

[7] Energy Information Administration, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants" (1996); FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others" (1996); and estimates made by the EIA Office of Coal, Nuclear, Electric and Alternate Fuels.

[8] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996*, DOE/EIA-0437(96/1) (Washington, DC, December 1997).

Figure 1. Status of State Electric Utility Deregulation Activity as of July 1, 1998



[a]California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia.
[b]Arizona, Maryland, Michigan, New Jersey, New York, and Vermont.
[c]Alaska, Delaware, Kentucky, Missouri, Ohio, South Carolina, and West Virginia.
[d]Alabama, Arkansas, Colorado, District of Columbia, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Nebraska, New Mexico, North Carolina, North Dakota, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming.
[e]Florida and South Dakota.
Note: Texas allows competitive wholesale wheeling as authorized by SB 373, enacted in 1995. Legislation authorizing retail wheeling will be revisited in 1999. California, Massachusetts, and New Hampshire each have regulatory orders and legislation in place.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

trended downward from a 1983 peak to a 16-year low in 1995, although they recovered somewhat in 1996.[9] A large worldwide surplus of uranium has also caused its prices to decrease precipitously over the past decade or more.

Keeping fuel costs down is a major goal for electricity producers in maintaining competitive prices. As a consequence, fuel suppliers will be faced with many challenges to cope with the coming changes to their industries and remain competitive. Chapters 1 through 5, on the fuel markets, examine some of the challenges and opportunities brought about by electric power industry restructuring. Each fuel market is addressed in a separate chapter, where issues important to that particular market are discussed. Because the fuels vary widely in their economic and technological characteristics and in their alternative power uses, there is no consensus set of issues applying to all markets. As a result, the individual fuel chapters vary in the depth and scope of their analysis. Chapter 6 presents the results of a quantitative analysis conducted to estimate the magnitude of the impacts that competitive electricity generation markets could have on the fuel supply industries, based on model projections from EIA's National Energy Modeling System.

[9] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), p. 181.

1. Impacts of Electric Power Industry Restructuring on the Coal Industry

The U.S. coal and electric power industries are tightly linked. Over 87 percent of all the coal consumed in the United States is for electricity generation by utilities, and coal is the primary fuel for more than 56 percent of utility power generation (Table 1). Deregulation of the electric power industry, therefore, has a potentially profound impact on the coal industry. Moreover, that impact will be compounded by a concurrent consolidation of the rail industry, which is the largest carrier of coal and a major determinant of the price of coal delivered to electric power generators.

Implications of Electric Power Industry Deregulation

The deregulation of electricity markets will have far-reaching implications for the coal industry. In the electric power industry itself, deregulation is expected to result in intensified price competition, growing price volatility, shorter-term wholesale electricity transactions, and industry consolidation and structural changes. Today, as the electric power industry is moving rapidly toward retail competition, the wholesale electricity market is already reaching full-scale, open competition. The deregulated wholesale market is proving to be highly dynamic; prices tend to be volatile and transactions short term. The electric power industry is undergoing consolidation through mergers and acquisitions and, at the same time, has started unbundling its generation, transmission, and distribution functions from an integrated structure.

Dynamics of a Deregulated Power Generation Industry

With open competition and electric industry unbundling, most U.S. electricity generators in the future are likely to function as "merchant" plants, much like oil and gas producers, with no guaranteed market for their output. These merchant plants will be in constant competition for sales of their output. Plant operators will look to cut costs wherever they can and to manage risks in both the fuel and electric power markets. The electric power industry has already started a consolidation, and it is expected to continue. At the same time, convergence between electric power, natural gas, and coal markets is also taking place.

All these developments reflect strong incentives for electricity generators to become lower cost producers, expand market share, and remain profitable in a deregulated environment. In a fully competitive retail electricity market, only those generators with costs low enough to produce electricity at market prices, as opposed to costs that are simply low enough to meet regulatory oversight, will be able to sell electricity profitably and remain viable.

Electric power generators will face new risks in a deregulated environment, and they must manage their operations to cover their costs in more competitive markets. Yet, greater uncertainty will prevail in virtually every aspect of their operations. Most notably, they will operate without a guaranteed market or price for their electricity. As retail competition unfolds, the market for their electricity will become even more uncertain in magnitude, timing, and price.

Risk management in power generation and in fuel purchasing will focus primarily on managing the spread between electricity and fuel prices, known as the "spark spread." Power generators will use various physical and financial techniques, such as futures or options contracts, to manage risks in both electricity and fuel markets. They will also attempt to pass on risks to fuel suppliers wherever possible. Such risk management techniques are well established in the oil and gas markets and recently have begun to emerge in electricity markets. In the near future, they will become important in coal markets as well.

Uncertainties in power markets will lead power generators to change their coal purchasing practices. They will shift from long-term to shorter term contracts to remain flexible in coal purchasing, and their contracts for coal purchases will include terms and conditions

Table 1. Electric Utility Net Generation and Coal Receipts by NERC Region, 1996

NERC Region	Coal	Other Fuel	Total Generation	Coal	Appalachian Receipts	Interior Receipts	Western Receipts	Total Receipts
	Billion Kilowatthours			Percent Share	Million Short Tons			
ASCC	0.2	4.8	5.0	4.6	NA	NA	NA	NA
ECAR	467.8	56.8	524.6	89.2	123.0	41.5	35.7	200.2
ERCOT . . .	104.2	117.7	221.8	47.0	0.0	51.3	29.1	80.5
FRCC	59.8	79.1	138.8	43.1	13.4	7.7	0.7	21.8
MAAC	106.7	98.1	204.7	52.1	43.5	0.0	0.0	43.5
MAIN	136.4	95.7	232.0	58.8	1.8	17.5	56.9	76.2
MAPP	115.6	44.3	159.9	72.3	0.0	1.3	70.6	72.0
NPCC	37.7	141.8	179.4	21.0	12.9	0.0	0.0	12.9
SERC	358.4	228.2	586.6	61.1	100.4	30.2	18.9	149.5
SPP	166.2	122.4	288.6	57.6	0.0	5.6	91.6	97.2
WSCC	184.7	344.8	529.5	34.9	0.0	0.0	104.3	104.3
Total[a]	**1,737.5**	**1,333.6**	**3,071.0**	**56.6**	**295.0**	**155.1**	**407.8**	**858.0**

[a]Excludes 6.4 billion kilowatthours of electricity generated in Hawaii, all from other fuels.
NA = Not available.
Source: Energy Information Administration Form EIA-759 for electric utility net generation by fuel type and Federal Energy Regulatory Commission Form 423 for coal receipts by coal-producing region.

enabling them to react to unanticipated changes in the coal market.

Complicating the above scenario is the regional disparity in coal dependence (Table 1). While 56.6 percent of all utility generation in the United States is coal-fired, regional dependence on coal varies widely, ranging from less than 5 percent for Alaska (ASCC) to almost 90 percent for the ECAR region (Figure 2). Further complications will arise from a consideration of the source of the coal used in power generation. For example, the SPP and MAAC regions are similar in their levels of coal dependence, but generators in the SPP obtain their coal mostly from suppliers in the West, whereas the MAAC region relies primarily on Appalachian coal. The difference in their coal sources may result in very different responses to deregulation.

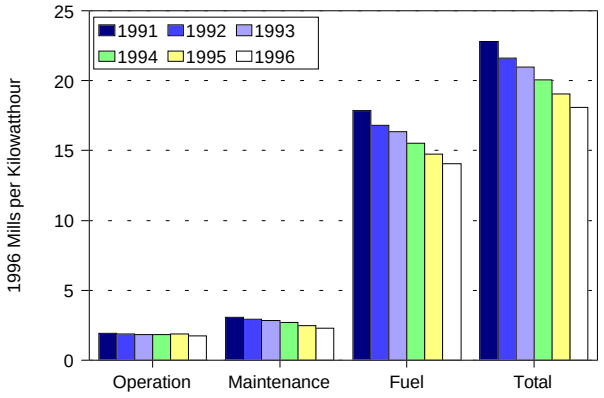
The Link to Coal Prices

The dependence of coal producers on the electricity generation market closely ties them to developments in the electric power industry. Once electricity markets are deregulated, power generators will try to cut fuel costs by putting pressure on both minemouth and delivered coal prices. Among the many strategies to cut costs, power generators will focus on reducing fuel costs, which are seen as being manageable and are the largest component of production costs at coal-fired power plants—over 75 percent. Power generators generally have less opportunity to cut nonfuel (operation and maintenance) costs (Figure 3). The importance of fuel costs is clearly reflected in today's incremental wholesale power sales, which are largely based on relative fuel costs.

Over the past decade, coal costs for electricity production have declined substantially. For example, between 1991 and 1996, they declined by 21 percent—from $17.84 to $14.08 per megawatthour (MWh) (in 1996 constant dollars)—while operation and maintenance costs remained flat. Much of the recent decline in coal costs is attributable to falling coal prices. Coal producers and carriers (primarily railroads) have improved their productivity and competed for utility coal business. In a deregulated electricity market, power generators are certain to look for still lower coal costs, adding pressure on both minemouth and delivered coal prices.

To remain competitive, power generators will intensify pressures on coal producers for lower coal prices, but will not be willing to make long-term commitments for coal purchases. This will mark a significant departure from past practices, with far-reaching impacts on the coal industry.

Figure 3. Average Power Production Expenses for Major U.S. Investor-Owned Coal-Fired Electric Utility Plants



Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

carriers wherever they can. This has already resulted in significant reductions in coal contract prices and duration. Price pressures mean lean profits for coal producers and new challenges to find ways to cut costs to remain viable. In addition, volatility in electricity markets may well be reflected in the coal markets. With the greater use of short-term transactions for coal and increasing market uncertainty, coal producers, like power generators, could well find themselves subject to considerable price and volume volatility and risks, which they will need to hedge.

The Coal Industry Response

Changing Industry Structure

Coal Production Trends

The result of a competitive, deregulated electricity market will likely be further consolidation in the coal industry. Pressure from electric power generators for lower coal prices will mean reduced revenues and, hence, profits, which will drive out smaller, inefficient coal producers. This will benefit larger companies, as larger size generally results in lower overhead and mining costs through economies of scale, diversification of business, and the availability of financial resources to make new investments in mines and to improve productivity.

Coal may also be included in attempts by energy companies to integrate their operations across energy sources. Combining electricity and gas in transactions is already a common business practice. This is one aspect of the widely discussed phenomenon termed "convergence" of the energy industry. Some coal producers today are packaging coal and sulfur emission allowances. Convergence could expand to include coal, as well as emission allowances, along with electricity and gas.

Only those coal producers with the ability to obtain financing and manage risks will survive. They must be able to face the challenge of investing with lower and less certain revenues per ton. Small coal producers may not have the financial resources to do this. Increasingly, balance-sheet financing of companies, based on the company's overall financial strength, will replace project financing of specific mining ventures. This, in turn, will favor the larger companies and may act as an incentive for further consolidation.

Coal Industry Concentration. The coal industry has been undergoing consolidation for some time, creating fewer but larger mines and firms and producing more coal (Table 2). Two basic forces have been driving consolidation in the coal industry. In the 1960s and 1970s, more stringent mine safety and reclamation laws forced many small mines out of operation. Then, in the 1980s, falling coal prices caused small, inefficient producers to close down or be bought out, and pressure to reduce costs motivated producers to seek economies of scale by forming larger units.[11] Under deregulated electricity markets, power generators will further increase the pressure on coal producers to lower prices, intensifying the recent trend toward increasing consolidation and concentration of mining operations and firms.

Nationally, concentration among coal producers has increased. The top four coal producers had a market share of 32.9 percent in 1996, up from 19.6 percent in 1986.[12] In coal reserve holdings, a key indicator of future production, concentration among the four largest reserve holders fell from 10 percent in 1985 to 7.2

[11] Electric Power Research Institute, *Structural Change in the Coal Industry: Coal Industry Concentration Trends, 1970-1994*, TR-105026 (May 1995).

[12] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 13; and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 15.

Table 2. Coal Production Trends

Industry Characteristics	1970	1980	1990	1996
Number of mines	5,601	3,969	2,707	1,903
Number of surface mines	2,662	2,082	1,285	1,018
Number of underground mines	2,939	1,887	1,422	885
Average production per mine, surface.	102	236	471	642
Average production per mine, underground	116	179	299	463
Percent of production east of the Mississippi River	93	69	61	53
Percent of production west of the Mississippi River	7	31	39	47

Source: Energy Information Administration, Form EIA-7A, "Coal Production Report," and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

percent in 1990.[13] However, a recent survey indicates that the concentration of reserve holdings may also be increasing. In 1996, the four largest reserve holders held 8.7 percent of total U.S. coal reserves.[14]

Increasing concentration in coal production can be seen in the Powder River Basin (PRB), the Nation's largest and fastest growing coal-producing region. Coal production in the PRB is dominated by a small number of large surface mines, which currently include 14 of the Nation's 15 largest mines, and is becoming increasingly concentrated. In 1986, the top 4 producers in the PRB accounted for 48 percent of its total output: Amax (14 percent), Arco (14 percent), Exxon (12 percent), and Nerco (8 percent). By 1996, the top 4 producers represented 77 percent of the Basin's total output: Peabody (33 percent), Kennecott (17 percent), Arco (15 percent), and Cyprus Amax (12 percent).[15]

The number of both surface and underground mines fell dramatically between 1970 and 1996, increasing the average production from both types of mines (Table 2, Figure 4). Surface mines on average produced six times more in 1996 than they did in 1970, due largely to the regional shift in coal production toward large western surface mines. Western coal production accounted for 47 percent of the U.S. total in 1996, up from only 7 percent in 1970. Deregulation of the electric power industry is likely to bolster this trend.

The coal industry is also increasingly becoming international. Foreign-affiliated coal firms made up only 1.4 percent of total production in 1976.[16] By 1995, three of the top five U.S. coal producers had foreign affiliations, and production by foreign-affiliated firms had risen to 30.7 percent.[17]

Another clear trend is that the coal industry is largely becoming composed of companies focusing almost exclusively on the coal business. Companies that currently have long-term interests in the coal industry tend to have more significant expansion plans; in fact, most recent acquisitions have been made by companies that have coal as their main business. Such firms also tend to operate mines more efficiently and reliably. Other types of companies—such as electric utilities, steel manufacturers, and oil companies—have mostly left the coal industry. For example, between 1989 and 1994, six petroleum companies sold or offered to sell their coal divisions.[18] It is noteworthy that such companies brought large amounts of capital to the coal industry, yet they failed to attain the same level of expertise and commitment as those dedicated primarily to the coal industry.[19] Kerr-McGee, the only remaining major

[13] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 10.

[14] National Mining Association, *Facts About Coal*, 1996 (data compiled from a National Mining Association survey of major producers may not be all inclusive), p. 14.

[15] Energy Information Administration, Form EIA-7A, "Coal Production Report."

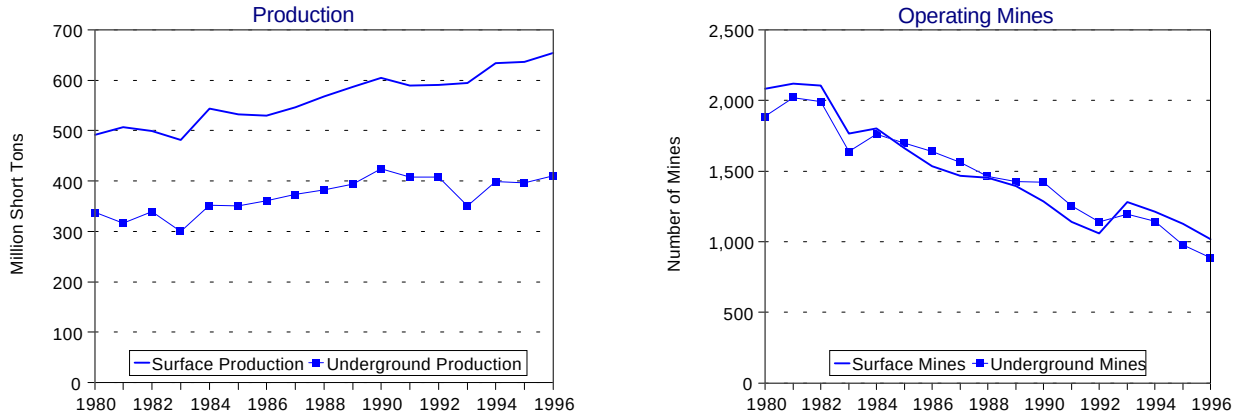
[16] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 13.

[17] Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(96) (Washington, DC, January 1998), p. 82.

[18] *Ibid.*, p. 54.

[19] Electric Power Research Institute, *Fuel Management for Competitive Power Generation-A Guide to Managing Change*, TR-107890 (April 1997), pp. 6-13.

Figure 4. Production and Number of Operating U.S. Coal Mines



Sources: Energy Information Administration, Form-EIA-7A, "Coal Production Report."

petroleum company with significant coal holdings, recently put those assets up for sale.[20]

On the other hand, the deregulation of electricity markets may drastically affect the current composition of the coal industry, if many multi-fuel conglomerates are formed to maximize the flexibility and reliability of their fuel supply options. Competitive pressures in the electric power industry will provide incentives to coal producers to reduce costs through mergers and acquisitions. This option will appeal to those producers who hope to take advantage of economies of scale and achieve greater flexibility in managing supply contracts with electric power generators. In the short run, this will increase concentration, but will also lead to further reductions in coal prices, increases in productivity, and larger mine operations. In the long run, however, increasing concentration in the industry could result in less competitive pressure among producers, at which point prices may level off or rise.

One way to reduce costs is to shift production to larger, more efficient, low-cost mines. This is reflected in the trend of mine closings over the past three decades. Between 1980 and 1996, the total number of coal mines fell by more than half, with the average mine in 1996 producing more than 2.5 times the 1980 level (Table 2). In addition, production at the largest mines is becoming increasingly concentrated (Table 3). By 1996, mines producing more than 1 million short tons represented nearly three-quarters of total output, and the largest 20 mines were responsible for 30 percent of total coal production. Mine closures also show relatively more underground mines than surface mines being closed. The resulting shift toward surface mines, coupled with the shift toward predominantly large surface mines in the West, increased the market share of surface-mined coal (Figure 4).

Surface mines have lower production costs per ton than underground mines, as can be seen in the lower minemouth prices of coal from these mines (Figure 5). For surface mines in the 500,000 to 1,000,000 short-ton range, prices at the minemouth in 1996 were 18 percent lower than those of underground mines. The difference was even more dramatic for surface mines that produced more than 1 million tons. Overall, the production cost per short ton for surface mines is less than half that for underground mines, reflecting the economies of scale of larger mines, the highly productive thick seams, and the low overburden ratios (cubic yards of overburden per ton of coal in the seam) of western surface mines.

Coal Industry Investment Trends

Opening a large coal mine requires a substantial investment. Also, planning, acquiring property rights, developing access, purchasing capital equipment, developing the mine and support facilities, and covering startup costs extend over several years before the mine is fully operational. Thus, potential investors in new mines face the challenge of recovering and earning a return on their invested capital.

[20] Intertec Publishing Corp., "Kerr-McGee to Exit Coal Business," *Coal Age* (March 1998), p. 10.

Table 3. Coal Production by Mine Size
(Percent of Total Production)

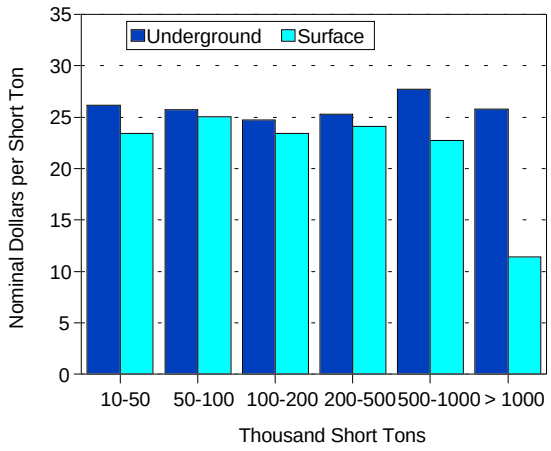
Mine Production (Short Tons)	1970	1980	1990	1996
1,000,000 and over	--	44.4	63.5	74.3
500,000 to 999,999	59.6	15.3	11.1	10.5
200,000 to 499,999	14.0	16.7	12.8	8.9
199,999 and below	26.3	23.6	12.7	6.2

-- = Not applicable.

Note: Components may not add up to 100.0 percent due to independent rounding.

Sources: U.S. Department of the Interior, Bureau of Mines, *Mineral Yearbook 1970*, "Coal—Bituminous and Lignite" (Washington, DC, 1972), Table 8; Energy Information Administration, *Coal Production 1980*, DOE/EIA-0118(80) (Washington, DC, May 1982), Table 5; *Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991), Tables 1 and 4; and *Coal Industry Annual 1996* (DOE/EIA-0584(96) (Washington, DC, November 1997), Table 6.

Figure 5. Average Minemouth Price per Ton by Mine Type and Mine Size, 1996



Sources: Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

The traditional method of financing coal mines is "project finance." By this debt financing method, each mine is treated as a separate business entity that must stand on its own financially. Lenders have limited or no recourse to the mining company itself. The mine entity obtains a loan based on projections of its expected future revenues and costs. A basic requirement for project finance is a contract (or contracts) with customers monetarily able to repay the debt. The financing agreement with the mine dedicates a certain portion of revenues from the contract(s) to repay the loan. The assurance of the revenues from the contract gives the mine entity its financial credibility. Project financing of coal mines has typically been based on long-term coal sales contracts with electric utilities.

Power generators now want contract terms that are shorter, with frequent re-openers to adjust the price of coal to the market, making the use of project finance techniques much more difficult. This problem is analogous to that of merchant power plants, which have no guaranteed market for electricity. In this new business environment, most financing will be done on a corporate balance sheet basis rather than through project finance. Investors—both equity and debt—will most readily fund mining companies that are large, diversified (even international), low cost, and financially strong. Such companies are likely to invest only in proposed new coal mines that offer production costs so low that they are viable under most future market scenarios.

Only about a dozen financial institutions specialize in financing coal mines, and these institutions see project finance as increasingly difficult for new mines. Investors also face higher risks due to the increased uncertainty facing coal producers. Those firms that are able to obtain debt financing will generally use more balance sheet financing, which favors the large and most profitable companies. Smaller firms will find it difficult to secure financing or to use balance sheet financing, leading to a further consolidation of the coal industry, which many analysts had considered to be nearly complete.

Effective risk management tools may help to provide the needed revenue stability to assist in securing financing for new investment. The amount of equity required will increase, and a broader set of investors, perhaps including international investors, may enter the market. One bond rating agency predicts that, during the next several years, mining projects will attempt to raise rated

debt (bonds) in the broader markets as an alternative to specialized lending sources.[21]

These financing considerations are likely to provide even more pressure to accelerate the consolidation of the coal industry. As mines become larger and more capital intensive, more capital will be needed for each mine. Also, small- and medium-sized coal producers will find it increasingly difficult to obtain financing, as their operations are too small to cover the increased capital investments. This, in turn, will favor the larger coal producers that have greater resources.

Not all financial analysts agree with this perspective, however. Some question whether the consolidation of the coal industry can go any further, arguing that additional gains from consolidation may not be feasible.[22] Some say that smaller operations, where the mine management has an ownership interest, have a stronger incentive to be profitable and may be run better than a mine operated by a large corporation.[23]

Changing Coal Prices

Whatever the outcome of coal industry consolidation, coal producers will increasingly face tough, ongoing competition based on low but volatile prices. They must respond to this challenge by finding ways to sell coal profitably at lower prices and to address emerging price and volume risks. Their efforts will focus on (1) cutting costs, (2) managing risks, and (3) redefining customer relationships. Some coal producers will be able to do this better than others, and they will have a competitive advantage.

Cutting Costs

Several methods are available for coal producers to reduce costs. First, they may improve the management of coal mining operations to increase efficiency. Second, mining firms may invest in more productive equipment to lower production costs. Third, consolidation may reduce costs through economies of scale and, at the same time, increase the producer's negotiating power to deal with large power generation and transportation counterparts. Another strategy to cut costs is to close down high-cost mines and/or to restructure some of them to be more economical. Efficient companies may be presented with opportunities to buy inefficient mines for a low price, make the necessary restructuring investments, and turn them into financially viable operations.

Such cost-cutting measures are not new. The coal industry has resorted to these measures to remain competitive and viable over the past decade to survive previous shakeouts. The coal industry's ability to change the way it structures its operations, utilizes labor, and adopts new technologies has resulted in substantially lower mine costs, which, when coupled with lower coal transportation costs, explains why coal prices to power generators have declined steadily in both nominal and real dollar terms over the past decade (Table 4). The emerging electric power industry deregulation and restructuring add to the ongoing pressure for coal producers and carriers to reduce costs. The coal industry is certain to continue to use those cost-cutting measures that have worked in the past as well as other new measures (such as forging new business relationships with power generators and coal carriers).

Mine Productivity and Labor Issues. Mine productivity, measured in tons per miner hour, has increased significantly over the past decade and a half, by 6.9 percent per year from 1980 to 1996, with gains for surface mines being slightly higher than for underground mines (Table 5). The gains are attributable primarily to capital investment in more efficient technology, the closing of less efficient mines and the

Table 4. Average Coal Prices Delivered to Electric Utilities
(Dollars per Short Ton)

Price	1970	1975	1980	1985	1990	1996
Nominal	7.13	17.63	28.76	34.53	30.45	26.45
Real (1996 dollars)	25.78	46.16	52.54	48.46	35.85	26.45

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal—Bituminous and Lignite" and "Coal—Pennsylvania Anthracite" chapters; **1980-1996**: Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

[21] A. Simonson and D. Nayduch, "Project Finance Criteria: Mining Projects," *Standard & Poor's Global Project Finance* (March 1997), pp. 18-21.

[22] Personal communication, Steve Fiscor, Executive Editor, *Coal Age* (July 3, 1997).

[23] Personal communication, Al Bertoni, National City Bank, Kentucky (July 28, 1997).

Table 5. Coal Mine Productivity by Mine Type
(Short Tons of Coal Produced per Miner Hour)

Year	Overall	Under-ground	Surface
1970	2.36	1.72	4.53
1975	1.83	1.19	3.26
1980	1.93	1.20	3.21
1985	2.74	1.78	4.24
1990	3.83	2.54	5.94
1996	5.69	3.57	9.05

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal-Bituminous and Lignite" and "Coal-Pennsylvania Anthracite" chapters; **1980-1990:** Energy Information Administration, *Coal Production Report,* DOE/EIA-0118, various annual issues; and *Coal industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997), Table 48.

opening of more productive mines, and the regional shift of production toward western coal. A more experienced work force and more flexible working conditions have also contributed to productivity gains.

Coal prices and mine productivity are closely related. As prices fall, coal producers must make more efficient use of all assets—including labor—for improved productivity, or they will lose profits. Inefficient mines eventually close, improving the average productivity for the industry. Conversely, during periods of high prices, high-cost mines can be opened profitably, thus lowering average productivity. The relationship between coal prices and productivity gains is circular: productivity gains allow coal prices to be lowered and price declines induce actions by coal producers that raise productivity and cut costs.[24] This has been the case in recent years, and electric power deregulation is expected to reinforce this trend through price pressure on coal producers.

Labor composes roughly half of total mining costs, making it a major cost component for coal producers.[25] As a result, there has been substantial substitution of capital for labor in the coal industry over the years, yielding significant productivity gains and mine cost reductions. With increasingly efficient equipment and technologies applied to coal mining, the number of coal miners has declined over the years—by 5.8 percent per year, from 154,645 in 1986 to 83,462 in 1996.[26] During the same period, total coal output has increased on average by 1.7 percent per year.

The United Mine Workers of America (UMWA), the largest union of coal miners with nearly 33,000 members, is opposed to electric industry deregulation. The union is concerned that efforts by coal producers to cut costs in a deregulated electricity market will eventually lead to wage cuts and layoffs for miners (as power generators look to reduce coal prices).[27] Recently, the UMWA began a major lobbying effort to build grass roots opposition to any legislation in Congress to deregulate the electric utility industry by 2000.[28]

In the past decade, coal producers so far have moved to make capital investments that increase mine productivity and cut labor costs. Is there room for further reduction in labor costs? One possibility is that the similarity of operations between surface mines and the construction industry may create downward pressure on wages in some surface mines. An influx of workers from the construction industry moving into surface mining operations may create a wage structure that resembles the construction industry, with resulting lower average wages.[29]

Innovation in Mining Technology. Coal producers have been able to raise productivity and lower costs, in part, by adopting new, more efficient production technologies. Underground coal mining has advanced from the conventional "room and pillar" method to the more efficient continuous mining method. Since about 1980, highly productive longwall mining has greatly expanded in the United States, contributing significantly to productivity gains in underground mining (Table 6).[30] In surface mining, productivity gains have come from the use of progressively larger draglines to excavate coal, as well as larger trucks to haul it. The industry has a history of innovation and of moving quickly to adopt new, more efficient mining methods and technologies. Such innovation can be expected to continue in the future.

[24] Electric Power Research Institute, *Central Appalachia: Coal Mine Productivity and Expansion*, IE-7117 (September 1991).
[25] *Ibid.*
[26] Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 40.
[27] Personal communication, Doug Gibson, Director of Communications, United Mine Workers of America (June 24, 1997).
[28] N. Knox, "U.S. Electric Deregulation Loses Steam," *The Detroit News* (June 19, 1997).
[29] Personal communication, Leslie Coleman, National Mining Association (June 1997).
[30] Energy Information Administration, *Longwall Mining*, DOE/EIA-TR-0588 (Washington, DC, March 1995), Chapter 4.

Table 6. Coal Production by Mine Type
(Million Short Tons per Year)

Mine Type	1970	1975	1980	1985	1990	1996
Surface Mining	272	361	492	533	605	654
Underground Mining	341	294	338	351	425	410
Longwall Mining	7	9	26	61	115	194
Total	**613**	**655**	**830**	**884**	**1,029**	**1,064**

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal—Bituminous and Lignite" and "Coal—Pennsylvania Anthracite" chapters; **1980-1990:** Energy Information Administration, *Coal Production Report,* (DOE/EIA-0118), various annual issues; and *Coal industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997).

Competitive pressures for lower coal prices will continue to encourage coal producers to take advantage of new technologies that increase productivity. The most promising new technologies currently on the horizon include further improvements in underground mining methods, the use of larger equipment in surface mining operations, and computerization applied to a wide range of administrative and mine maintenance activities.

Technological improvements in underground mining methods have been a major driving force for the substantial gains in productivity over the past decade, particularly the spread of longwall mining. Further gains may be obtained from more automated longwall operations (reducing labor requirements), faster advancing longwalls with deeper cutting shearers (to increase extraction rates), and more rapid and reliable conveyors (to speed coal haulage).[31] Increased use of computer controls with "expert systems" that draw upon human experience are also expected to improve longwall productivity. Real-time monitoring of the cutting blades can increase or reduce pressure to take full advantage of the equipment while reducing wear and increasing reliability.

Faster continuous miners also offer potential improvements in productivity. A mid-1970s continuous miner would produce at 5 tons per minute or less. Today's continuous miners can cut 10 tons per minute and load at 15 to 20 tons per minute.[32] Increased output and reliability can be achieved through improved drill bits and roof bolting technology. Increased reliability and more repairable equipment offer further gains in productivity. The use of self-diagnostic equipment that can direct repair personnel to the source of the problem will cut repair time.

In surface mining, increasing productivity is also closely tied to improvements in technology. Gains have come from the use of larger, more powerful draglines and dozers for strip mining and larger coal loaders and haulers to carry the coal. Manufacturers have noted that sales of trucks below 200 tons capacity have recently dropped, while sales of trucks above 200 tons have increased. Recently, the first 300-ton trucks have been introduced in the Powder River Basin.[33] New designs in buckets also offer improved performance for large draglines.

Technological innovation can also improve administrative and auxiliary work outside the mine. Using electronic data interchange (EDI), coal producers can speed the processing of purchase orders and billing. EDI can also interconnect the computer systems of coal producers, transporters, and power generators. The Rail-Utilities-Mining Group, formed in October 1996, is developing shipment, scheduling, routing, and payment standards for coal and coal transportation services.[34] Industry standards for coal quality analysis results and invoices are also under development.

Improvements in the technology for handling coal are also possible. One example is the on-line coal quality analyzer, which provides real-time sampling of coal quality. This ensures consistent coal quality and the ability to meet varying specifications for different customers—capabilities that will be valuable in a competitive short-term market. Real-time analysis of coal may also facilitate the creation of coal hubs, where

[31] *Ibid.*, Chapter 5.
[32] Electric Power Research Institute, *Central Appalachia: Coal Mine Productivity and Expansion*, IE-7117 (September 1991), pp. 2-11.
[33] R.A. Carter, "Battle of the Behemoths," *Coal Age* (January 1997), pp. 24-25.
[34] J.P. Bradshaw, "Doing Business in Cyberspace," *Mining Voice* (March / April 1997), pp. 20-25.

coals are blended to meet a wide variety of specifications. By interfacing with the accounting systems of the coal producer and power generator, on-line analyzers can also be used for payment purposes.[35] Their use will reduce laboratory and labor costs and ensure timely coal quality adjustments to the price of coal on the basis of coal quality.

Managing Risks

Coal producers will need to manage new risks arising from uncertainties in the deregulated electricity market. Power generators, facing increasingly uncertain electricity prices and sales volumes, will focus on managing the "spark spread"—the price differential between electricity and fuel—both to cover costs and to earn a return. They can manage the spread, to some extent, with risk management instruments, such as futures or options contracts. They will also try to manage their risks by sharing them with fuel suppliers, for example, by linking fuel purchase arrangements to electricity market conditions.

In addition to uncertainties arising from risk management efforts by power generators, coal producers must also deal with new uncertainties of their own. Coal contracts are growing shorter, more coal is sold on the spot market, and sales to power generators are becoming more uncertain. This uncertainty creates larger price volatility, and the resulting risks can have a significant impact on profitability unless steps are taken to manage them. A variety of methods or tools—financial, physical, and organizational—are available for coal producers to manage these new risks.

Coal producers may mitigate price risks by using financial risk management tools, such as forward or futures and options contracts. Although futures contracts for coal are not yet offered by any institutionalized exchange market, when offered, they will allow coal producers and power generators to lock in a coal price in the short to intermediate term. If the market coal price declines, the producer has the option either to sell the coal at the contract price or to sell the futures contract.

Because they are standardized in terms of quantity, quality, and delivery requirements, futures contracts are traded on commodity exchanges, allowing firms to use futures contracts markets as a means of price discovery as well as for hedging risk. Futures contracts have a small degree of flexibility in the contract specifications, but their homogeneity is the key to their usefulness.

The development of standard futures contracts for coal has lagged behind those for natural gas and electricity because coal prices are less volatile than those of other energy commodities and coal is more variable in quality. The New York Mercantile Exchange (NYMEX), a major futures exchange for oil, natural gas, and electricity, received approval from the Commodity Futures Trading Commission on May 11, 1998, for a Central Appalachia coal futures contract, which it hopes to offer in late 1998 or early 1999.[36] This contract will cover clean-burning coal with delivery to ports along the Big Sandy River and the Ohio River from Big Sandy, Kentucky, to Huntington, West Virginia. NYMEX is considering a Powder River Basin coal futures contract as well.

Until coal futures contracts are established, coal producers can use (non-standard) forward or options contracts to reduce price risk. Arco Coal Sales has offered call options on its coal, with delivery dates between 1999 and 2004.[37] Kennecott Energy is reported to have sold options to power marketers for delivery of PRB coal in 1999.[38] Zeigler Coal Holding is also rumored to be selling coal options, but Zeigler officials will say only that they are interested in the idea.

A coal producer can also purchase or sell an electricity or natural gas futures or options contract, a practice called "cross-commodity hedging." For example, a coal producer may purchase an option to buy electricity at a "strike" price of $25.00/MWh. The coal delivery contract may specify a price of coal that translates into $25.00/MWh. If the price of coal increases to a level that translates to $28.00/MWh, the producer can sell the coal on the spot market, realizing a profit of $3.00, and instead provide electricity to its customer through the futures contract.

The creation of regional "coal hubs," where coal can be blended and delivered to the ultimate consumer by multiple modes of transportation, has been proposed as a physical method to manage risks.[39] A coal hub would provide a common regional delivery point where coals

[35] R.C. Woodward and B. Lee, "On-line Analysis Evolves," *Coal Age* (March 1997), pp. 22-25.
[36] Pasha Publications, Inc., "Feds Approve Coal Futures Contract," *Coal Outlook* (May 18, 1998).
[37] Pasha Publications, Inc., "Arco Seeks Bids on Coal Option Contracts," *Coal Outlook* (March 9, 1998).
[38] Pasha Publications, Inc., "Kennecott Sells Options for Future PRB Delivery," *Coal Outlook* (January 26, 1998).
[39] M . Hyrnick, "Management of Coal Options Through Fuel Flexibility," 1995 EPRI Fuel Supply Seminar, New Orleans, LA.

can be traded and blended to meet the specifications of a wide variety of coal users, allowing coal producers and generators greater flexibility in transactions. The feasibility of coal futures contracts would also increase with the creation of hubs representative of specific markets. To date, however, no coal hubs have been created.

Coal producers may also reduce risks through diversification of their customer base, allowing them to reduce market risk by becoming less dependent on any one customer. For example, some producers export a portion of their output, reducing the risks associated with the domestic market. Exports traditionally make up a small part of U.S. production—only about 8.5 percent in 1996[40]—but increased uncertainty in the domestic U.S. market may make international markets more attractive. Exports may be a hedge against declining U.S. prices,[41] but they may not be an option for all producers. Indeed, export markets are highly volatile and have their own risks.

Other potential approaches to risk management create closer ties between companies. Kennecott Energy recently signed an alliance agreement with Enron Capital & Trade Resources making each the preferred provider of the other in joint coal/energy deals.[42] Traditional mergers, both with other producers (horizontal integration) and with customers (vertical integration), are also options. Each of these organizational methods allows parties with complementary needs and resources to share the new risks within the deregulated electricity market.

Changing Customer Relationships

The deregulation of electricity markets is already changing the relationship between coal producers and their power generation customers in significant ways: coal supply contract terms are changing in that (1) purchase arrangements are becoming shorter in duration and existing contracts above market price are being renegotiated; and (2) new types of business arrangements are emerging. Many of these new relationships differ greatly from the traditional arms-length relationships between electric utilities and their fuel suppliers.

Because both electricity generators and coal producers will need to focus on meeting the demands of the competitive electricity marketplace, both entities will have a greater commonality of interest than they had in a regulated marketplace. Cooperative relationships between fuel buyers and sellers are already emerging, with the objective of sharing opportunities and risks in the electric power marketplace. Vertical integration may even be an option.

Changing Contract Terms. The procurement of coal by power generators traditionally has involved a mix of contracts of various lengths as well as spot purchases. Deregulation of the electric power industry will create uncertainty about electricity and fuel prices and their volumes due to the lack of guaranteed markets for electricity. Electricity sales will vary over time and more widely across customer types. The result will be a dynamic market situation in which the parties involved must be able to respond quickly to changing market conditions. Faced with these uncertainties, committing to conventional long-term coal contracts will be increasingly difficult for power generators.

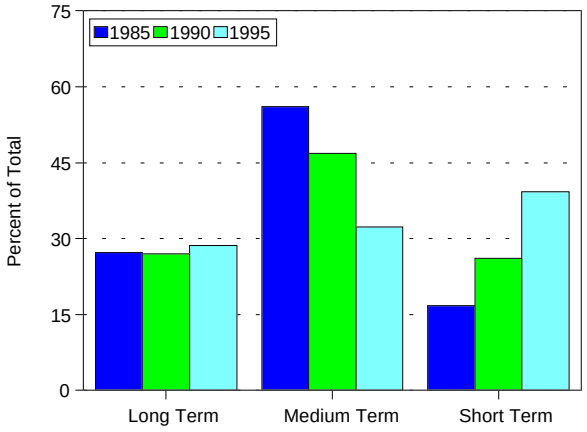
Large amounts of coal have traditionally been purchased under long-term contracts, some of which exceeded 30 years. However, contract durations have increasingly become shorter. In terms of tonnage share, deliveries of coal under contracts of shorter duration (less than 10 years) more than doubled from 17 to 39 percent between 1985 and 1995, while medium-term (11 to 30 years) deliveries shrank from 56 percent to 32 percent, and longer term (over 30 years) deliveries remained relatively unchanged from 27 percent to 29 percent during the same period (Figure 6). As coal prices have fallen over the past decade, and are expected to continue falling for some time to come, power generators have been shortening contract durations.

Uncertainties in deregulated markets will lead power generators increasingly toward shorter term, more flexible arrangements, including spot market purchases. (Spot market coal purchases currently account for less than 20 percent of all utility coal receipts. Their prices are substantially lower than contract prices.)[43] New coal contracts tend to have re-openers and other clauses that increase flexibility or pass on some of the electricity market risks to coal producers.

One new type of contract that has emerged over the past several years ties the price of coal to the price of

[40] Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 76.
[41] A. Blumenfeld, "Exports to 'Swing' into Favor in the United States," *Coal Age* (July 1997), pp. 35-36.
[42] Pasha Publications, Inc., "Enron, Kennecott Form Alliance," *Coal Outlook* (March 9, 1998).
[43] Energy Information Administration, *Electric Power Monthly, September 1997*, DOE/EIA-0226(97-09) (Washington, DC, September 1997).

Figure 6. Distribution of Contract Coal Tonnage by Contract Duration



Source: Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October, 1995), Table 32, and the Coal Transportation Rate Data Base.

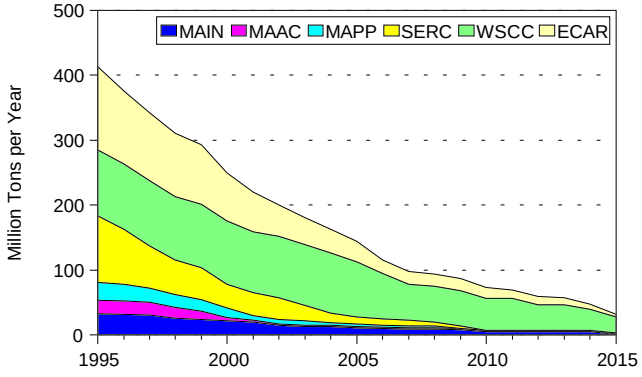
wholesale electricity. This is a way for power generators to ensure that their fuel costs will remain competitive. In some cases, the coal price is linked to specific electricity market transactions. Through this type of coal supply contract, the coal producer and the power generator share both the opportunities and the risks.

While new coal supply contracts are becoming increasingly short term, existing long-term contracts are also being renegotiated for lower prices. Many of the long-term coal contracts currently in force were signed when the electric power industry was regulated. The expectation at that time was that fuel costs under these contracts could be recovered from ratepayers through the normal ratemaking process. For many utilities, this included a "Fuel Adjustment Clause," which, subject to prudence review, automatically passed on all changes in fuel costs to customers. Since these contracts were entered, however, coal prices have declined substantially, making the price of coal under many remaining contracts higher than the current market price. It is no longer clear whether the cost of coal under these above-market priced contracts can be recovered from electricity customers once the industry is fully deregulated. Above-market contracts are making many generators uncompetitive in the current wholesale market. As a result, above-market contracts are considered to be potential "stranded liabilities" that may not be recovered.

What happens to above-market contracts will have an impact on power generators, their coal suppliers, and the overall coal market. Many will be renegotiated, bought out (as was done in the past), or will expire over the next several years. In order to avoid financial losses, power plant operators will need to ensure that these contracts are renegotiated or terminated before their plants are exposed to the full effects of open competition. Thus, timing is particularly important.

A recent analysis of coal supply contracts in the six National Electric Reliability Council (NERC) regions most dependent on coal shows that above-market contracts constitute a large portion of the coal contracts in force, but that over half will expire by 2005 (Figure 7).[44] At the beginning of 1995, 413 million short tons out of 492 million short tons under long-term contract in those regions were above market prices. This tonnage was estimated to decline to 342 million short tons by the end of 1997, but 144 million short tons will still remain in effect at the end of 2005. Of this, about 27 million short tons will be for coal from "captive" mining operations, mostly in the Western Systems Coordinating Council (WSCC), where the plant operators also own the mines.

Figure 7. Above-Market Contract Coal Returning to Market, 1995-2015



Source: Hill & Associates, Inc., *Generating Cost Study, 1996* (Annapolis, MD, 1996).

[44] Hill and Associates, Inc., *Generating Cost Study, 1996* (Annapolis, Maryland). The six regions are the East Central Area Reliability Coordination Agreement (ECAR), the Mid-Continent Area Power Pool (MAPP), the Mid-Atlantic Area Council (MAAC), Mid-American Interconnected Network (MAIN), Southeastern Electric Reliability Council (SERC), and Western Systems Coordinating Council (WSCC). "Above market" in this study is defined as above the price that would be obtained for a new coal contract—typically about 5 percent above the spot price. This premium reflects the added benefit in terms of reliability, security of supply, and coal quality assured by contract purchase.

Coal tonnage under above-market contracts and their expiration dates vary among the NERC regions. The East Central Area Reliability Coordination Agreement (ECAR) region originally had the most above-market contracts (128 million tons in 1995); however, all but 30 million tons will expire by 2005. Declines in all the other regions except WSCC are similarly precipitous. In WSCC, 85 million of the 101 million tons of above-market contract coal outstanding in 1995 will still not have expired by the end of 2005. This largely reflects the fact that many of the power plants in this region are located at the minemouth, and some are captive operations.

Pressures on both electricity generators and coal producers to renegotiate terms of above-market contracts (or to restructure captive mining operations) will be intense, as coal sales to power generators ultimately depend on the amount of electricity the generators can sell.[45] Coal producers may be more willing to renegotiate above-market contracts than before to avoid seeing their customers become uncompetitive and nonviable.

Coal contracts can be above market price due to high transportation rates. Thus, coal carriers may also feel pressure to renegotiate their transportation rates. If the carrier has a degree of market power (as discussed below), however, the generator's negotiating leverage may be more limited.

While above-market coal contracts will eventually cease to be a problem for most electric utilities, such contracts have been an important source of revenue for many coal producers. Expiration and renegotiation of these contracts, which have ensured profitability and stability for coal producers, may create financial difficulties for many coal producers. The renegotiation and expiration of above-market contracts in the past have already reduced the contract premiums substantially. For example, in the Southeastern Electric Reliability Council (SERC) region, contract premiums dropped from 23 percent in 1990 to 10 percent in 1996.[46] With fewer long-term contracts, coal producers will sell more coal on spot markets, which are more competitive than contract markets and bring lower prices (and profits) to the coal producers.

New Business Arrangements. Increasing competition is forcing many electricity generators to rethink how they deal with fuel suppliers. New cooperative relationships are, in some cases, replacing the traditional arms-length, adversarial purchasing practices. Opportunities are now emerging for coal producers, railroads, and electricity generators to develop new strategic relationships, causing new arrangements, such as strategic alliances, "coal-by-wire," "tolling," and "energy swaps" to emerge.

By working together, coal producers, carriers, and generators can coordinate their operations both to take advantage of opportunities and to create economies. For example, they can share market information and structure deals to realize specific opportunities. Coal producers and railroads can jointly schedule transportation to reduce downtime, and closer coordination can reduce the size of inventories and move the parties closer to "just-in-time" deliveries. Taken a step further, coal producers may be able to help manage coal inventories at some power plants. In addition, centralized rail fleet operations may allow carriers to reduce the number of cars they need, reducing capital costs, and master contracts that consolidate volumes over multiple plants may reduce rates and allow power generators to optimize shipments of coal among power plants.

Strategic alliances offer one avenue for cooperating to share opportunities and risks. A number of major coal companies and electricity generators are currently seeking such relationships. For example, Cyprus Amax Minerals Company has announced that it has formed strategic alliances with 12 of what it calls "leadership utilities," including coal tolling arrangements.[47]

In tolling, a power marketer (or fuel supplier) contracts with the operator of a generating plant to convert the power marketer's fuel into electricity, which is delivered over a transmission line to an agreed-upon location. The generator does not take title to either the fuel or the electricity, but is paid a tolling fee for its services. The power marketer owns the electricity output and is responsible for selling it. Several coal tolling arrangements have recently been announced (Table 7). A power plant with underutilized generation capacity may generate greater revenues by tolling the available plant capacity, and the power marketer may have access to low-cost fuel and have power marketing opportunities.

Tolling as currently practiced is a temporary opportunity when the situation is right, not a permanent relationship. It is typically used when a plant operator's

[45] C. Seiple, "At-Risk Generation: Implications for the Coal Industry," *Coal Age* (March 1997), p. 28.

[46] T. A. Myers and B. O'Neill, "Converging Coal Prices in Retail Power Markets," *Coal Age* (June 1997), p. 42.

[47] R.D. Rosenberg, "Who Wins in a Competitive Power Market: Gas? Coal? Or Rail & Mining Interests?" *Public Utilities Fortnightly* (April 1, 1997), pp. 41-45.

Table 7. Announced Coal Tolling and Energy Swap Transactions

Toller	Utility	Size of Deal	Plant	Type of Deal
Vitol Gas & Electric (VGE)	Public Service Electric & Gas	750,000 tons	Hudson	Coal Tolling
VGE	Midwest utility	700,000 tons	NA	Energy Swap
VGE	Western utility	400,000 tons	NA	Energy Swap
VGE	Lower Colorado River Authority	200,000 tons	NA	Energy Swap
VGE	LCRA	500,000 tons	Fayette	Energy Swap
VGE	Commonwealth Edison	NA	NA	Energy Swap
Louisville Gas & Electric (LGE)	PSEG	750,000 tons	Hudson	Coal Tolling
LGE	Ohio Edison	945,000 tons	Burger	Coal Tolling
Entergy Services	Southern Co.	60,800 MWh	Crist	Coal Tolling
Carolina Power & Light	Appalachian Power	NA	Amos	Coal Tolling
Detroit Edison	Wisconsin utility	NA	NA	Coal-by-Wire
Cyprus Amax Coal	Ohio Edison	800,000 tons	Burger	Energy Swap
Zeigler Coal	NorAm Energy Services	100,000 tons	Springfield, IL	Coal Tolling
CINergy	East Coast utility (VA/MD)	800,000 tons	NA	Coal Tolling
Lakeland Electric & Water	NP Energy	9,000 tons	NA	Coal Tolling

NA = Not available.

Sources: **VGE:** *Coal Outlook*, 20:7; *Coal Outlook Supplement* (February 3, 1997);*Coal Outlook*, 20:47; *Coal Week*, 23:3; *Coal Outlook*, 21:20; *Coal Outlook*, 21:17; **LGE:** *The Energy Daily* (February 18, 1997); **LGE:** *Power Markets Week* (June 24, 1996); **Entergy**: *Power Markets Week* (February 12, 1997); **Carolina P&L:** *Coal Outlook Supplement* (August 5, 1996); *Coal Outlook*, 20:9; **Detroit Edison:** *Coal Outlook*, 20:21; **Cyprus Amax:** *Coal Outlook*, 23:2; **Zeigler Coal:** *Coal Outlook*, 21:10; **CINergy:** *Coal Outlook*, 20:27; **Lakeland:** *Coal Transportation Report*, 17:6.

access to power market information and/or low-cost fuel supplies is restricted in some way, or when the plant operator has a different tolerance for risk. A customer may also initiate the process, acquiring fuel and having it converted into electricity by a generator, buying the electricity at a lower price than the same generator could offer. "Reverse tolling" occurs when the value of the coal is greater in the spot market than in the electricity market. An electricity generator may have a stockpile of coal that, if burned, would receive a price in the electricity market that is less than needed to cover its generation cost. Through reverse tolling, the coal is sold on the spot market, and the generator can earn a profit without burning the fuel itself.

Energy swaps are a more flexible arrangement than tolling, in which the parties involved agree to exchange coal, electricity, gas, or cash. For example, a power marketer may arrange to supply a power generator with coal in exchange for electricity. Unlike a tolling deal, the power generator is not obligated to burn the coal, but is free to sell the coal to another party. Moreover, the timing and location of each part of the transaction may vary, provided that a method is agreed upon to assign value to each part.

Tolling, reverse tolling, and energy swap transactions are manifestations of the "convergence" of energy markets, which has emerged from a dynamic power marketplace just since 1995. These methods of doing business reflect the new fluidity in the market as well as the new characters of the players, all of whom are competing for market share and profit. These transactions also show how the inputs and outputs of electricity generation are becoming virtually interchangeable, providing mechanisms for fuel suppliers, electricity generators, and power marketers to operate in each other's markets.

The Role of the Railroads in Competitive Electricity and Coal Markets

The coal industry is facing a double challenge. Just when the major customers of the coal industry are being restructured, the railroads—the dominant transportation mode for coal—have been undergoing a significant consolidation. The role of the railroads in bringing coal to market is vital, and rail industry consolidation is

controversial. Any changes in the structure of the railroad industry may affect the economics of both the coal and electric power industries.

Major railroads are merging to create larger companies, and concerns are being raised about their market power. Coal shippers—i.e., coal suppliers and power generators—are concerned that the railroads may seek to capture larger economic rents from them and, as a result, adversely affect their competitiveness. Some fear that by favoring the shippers that provide them with the most profitable traffic, railroads will charge discriminatory rates to others. The railroads contend that competition will be adequate, and they argue that larger operations will reduce costs and improve service and efficiency through economies of scale.

Importance of the Rail Industry to Coal

Although transportation modes differ among the regions, railroads are the most widely used mode of transportation for coal. Nearly 58 percent of all coal delivered to consumers in 1996 involved rail as the primary transport mode (Table 8). Further, average coal hauls are getting longer, reflecting the increased penetration of western coal carried by rail into southern and eastern utility coal markets. According to one study, the average haul of contract utility coal by rail lengthened by 33 percent, from 485 to 643 miles, between 1979 and 1995.[48] Coal is an important cargo for the railroads as well. In 1996, Class I railroads, defined as systems with operating revenues of more than $250 million, received 22.5 percent of their gross revenues from transporting coal, and coal composed 43.8 percent of the total tons of freight hauled by rail.[49]

While the distance coal travels has lengthened, average coal transportation costs have been declining for every mode over the past decade. Although rail rates for coal per ton mile increased slightly in nominal dollar terms, they declined by 51.0 percent in real dollar terms from 1985 to 1995.[50] Such declines (in rates per ton mile) have contributed to the increased competitiveness of more distant western coal sources in eastern markets. The competitiveness of different coal-producing regions is, therefore, sensitive to rail rates, and even small differences in rates can tip the balance in regional competition.

Because of differences in shipping distance and transportation mode, transportation costs vary greatly among different sources of coal. Eastern coal is costlier at the minemouth, but its transportation costs are lower, involving relatively shorter hauls to consumers not just by rail but also by low-cost barge. Low-cost western coal is shipped primarily by rail over great distances, thus involving a larger transportation cost. In 1995, coal transportation costs on average represented 11.8 percent of the delivered price for Interior region coal, 19.9 percent for Appalachian coal, and 51.4 percent for western coal.[51] For some western coal hauls, transportation costs account for up to 75 percent of delivered fuel costs.[52]

Increasing Rail Concentration and Concerns

The first single-company transcontinental railroad, the Canadian Pacific Railway, was completed more than 100 years ago, in 1887. All other North American railroads both before and since have provided only regional service. However, the present trend in the rail industry

Table 8. Coal Transportation by Mode, 1996

Mode	Rail	Water	Truck	Conveyor	Total[a]
Thousand Short Tons	611,674	247,935	99,941	98,934	1,059,892
Share of Total (Percent) . . .	57.7	23.4	9.4	9.5	100.0

[a]Total includes 1,408,000 short tons for which the transportation mode is not known.

Source: Energy Information Administration, Form EIA-6, "Coal Distribution Report." See *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 65.

[48] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 34; and the Coal Transportation Rate Data Base.

[49] Association of American Railroads, *Commodity Freight Statistics* (1997).

[50] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 37; and the Coal Transportation Rate Data Base.

[51] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 50; and the Coal Transportation Rate Data Base.

[52] G. E. Vaninetti and J. J. Valentine, "Outlining the Impacts of Utility Deregulation on Railroads," *Coal Age* (December 1996), p. 51.

is toward increasing concentration, and the possibility that the U.S. rail market may be dominated by two major transcontinental railroads is even being discussed.[53]

In 1970, there were 71 Class I railroad companies. By late 1996, they had been combined into only nine.[54] Among western railroads, mergers over the past 16 years have resulted in only 2 major railroads, Burlington Northern-Santa Fe and Union Pacific-Southern Pacific. The most recent proposed development—the division of Conrail between CSX and Norfolk Southern—will leave only two major lines to serve the eastern part of the country. Currently, 5 companies—Burlington Northern-Santa Fe, Union Pacific-Southern Pacific, Conrail, CSX, and Norfolk Southern—combine to account for 90 percent of total railroad revenue from coal transportation.[55]

Perhaps an exception to the trend toward fewer, increasingly large railroads is a proposed plan by the Dakota Minnesota & Eastern (DM&E) Railroad to add a third railroad option to the PRB coal-producing region. This plan proposes to create a new railroad both by purchasing and upgrading existing track and by investing in new track. If it becomes a reality, the plan will create more railroad competition in the increasingly important PRB coal supply region. With this new railroad, DM&E Railroad hopes to capitalize on new business from utilities not yet using PRB coal in the Midwest and East.[56]

With the railroads carrying the largest share of coal shipments, coal shippers are concerned that the increasing rail concentration may weaken competitive pricing and affect them adversely through higher rail rates. Many coal shippers believe that the rail rates they receive depend on the intensity of competition among the carriers serving them. They argue that increasing concentration among railroads creates fewer choices for coal deliveries. Particularly concerned are "captive shippers," who have only one transportation option. Coal shippers also perceive that railroads can attempt to maximize their profits by favoring coal producers and power generators they think will give them the most profitable traffic.[57] They also claim that duopoly pricing could develop, with railroads implicitly colluding with each other to set prices at higher than competitive rates.[58]

The railroads, on the other hand, contend that competition will be adequate and that, to compete and survive, they need to take advantage of economies of scale through mergers and acquisitions. Reducing costs and improving performance, they argue, will ultimately benefit rail customers through lower transportation costs.[59] They also suggest that a larger geographic scope of company operations may broaden markets for coal producers and offer more coal supply choices for electricity generators.

New Rail Technologies for Moving Coal

The railroads have adopted many cost-cutting measures in the past. They have already reduced train crews where possible (for example, phasing out the brakeman position and leaving only the engineer and conductor to run a train[60]). Further cost savings from reductions in train personnel are unlikely. Future productivity gains are more likely to come from improvements in the capital stock. The old carbon steel cars are being replaced by ones made of lighter materials—stainless steel in the East, aluminum in the West.[61] Ultra-light, high-strength composites are being considered for use in the next generation of cars.[62] Increased use of alternating current locomotives will also improve productivity.[63]

Railroads are continuing to adopt technological innovations that offer more options to their customers and greater flexibility in operations. One such example is the "coaltainer," a specially designed container for

[53] C. Jones, "Whose Pound of Flesh is Extracted by Deregulated Markets?" *Power* (April 1997), p. 19.

[54] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-1107301 (December 1996), p. 3-1.

[55] *Ibid.*, p. 3-12.

[56] "Industry Reacts Cautiously to DM&E Project," *Coal Transportation* (June 16, 1997).

[57] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-107301 (December 1996), p. 2-2.

[58] R. D. Rosenberg, "Who Wins in a Competitive Power Market: Gas? Coal? Or Rail & Mining Interests?" *Public Utilities Fortnightly* (April 1, 1997), pp.41-45.

[59] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-107301 (December 1996), p. 3-2.

[60] D. M. Sawinski, ed., *U.S. Industry Profiles, The Leading 100* (first edition, 1995), p. 506.

[61] Chilton Publications, "Conrail Builds 600 Stainless-steel Rail Cars," *Iron Age New Steel* (September 1997).

[62] G. Welty, "Will Composition Enter the Mainstream?" *Railway Age* (August 1997).

[63] C. Deutsch, "Riding the Rails of Technology," *New York Times* (August 1, 1997).

intermodal transportation of coal. The containers can be transported both by rail and by truck, creating the equivalent of a rail spur without having to build one.[64] This and other new technologies may provide a competitive alternative for power generators who are captive to a single carrier.

Another innovation is the use of real-time satellite monitoring to improve the scheduling and routing of trains through computerized traffic management systems. Electronic data interchange (EDI), already extensively used by most railroads, can be expanded to offer potential improvements in many areas, such as better coordination among coal mines, railroads, and power generators for reduced cycle times and inventory levels. EDI will become increasingly important as more electricity generators move toward "just-in-time" inventory management. Norfolk Southern has already begun marketing this type of service.[65]

Options for Coal Shippers To Increase Rail Competition

Most rail rates are generally negotiated between the shipper and the railroad. As competitive pressures rise, coal shippers will seek to have as many options as possible for their shipments to give them greater leverage in rate negotiations. Such options for shippers include increasing access to alternative modes of transportation, forming new relationships, and using transactions that reduce transportation costs.

Consolidation of the electric utility industry may, in itself, create more choices for power generators. Larger companies, for example, may have more options in plant dispatch, which will enable them to dispatch those power plants getting the best rail rates. In addition, the larger size of the merged power companies may give them leverage to negotiate lower rail rates through volume discounts.[66] Many of the utility mergers that have taken place so far have been between utilities that predominantly use coal.

The most direct approach to fostering competition, where feasible, is to create new or extended tracks, called "spurs," from a power plant to a second railroad line, giving the power company access to a competitive delivery option. Several electric utilities have recently built or are building new spurs (Table 9). Sometimes, the mere threat of building a spur can force railroads to renegotiate prices.

Rates may also be reduced by cooperation among railroads, coal producers, and power generators to increase the efficiency of rail operations. Strategic alliances among coal producers, power generators, and railroads have the potential to control costs and risks in a deregulated market. Shippers and carriers can also work together to create economies of scale. For example, by creating a centralized operation for a group of plants, the railroad can reduce the number of cars in its rolling stock, resulting in lower capital costs.

Table 9. Recent Railroad Spur Development Activity

Utility	Plant	Original Carrier	Status	Connection
Grand Island Electric Dept., Nebraska	Platte	UP	Considering	Burlington Northern Santa Fe
Nebraska Public Power District	Gentleman	BN	Completed	Union Pacific-Southern Pacific
Omaha Public Power District.	Nebraska City	BN	Planned	Union Pacific-Southern Pacific
Houston Power & Light	Parish	ATSF	Completed	Union Pacific-Southern Pacific
Alabama Power Company.	Miller	CSX	Approved	Norfolk Southern
Savannah Electric & Power	McIntosh	CSX	Completed	Norfolk Southern
Western Farmers Electric Cooperative	Hugo	Kiamichi	Underway	Texas, Oklahoma & Eastern
Tennessee Valley Authority	Kingston	NS	Planned	CSX
Gulf States Utility	Nelson	Kansas City Southern	Completed	Union Pacific-Southern Pacific
Mid American	Council Bluffs	BN	Completed	Union Pacific-Southern Pacific
Wisconsin Electric	Pleasant Prairie	UP	Underway	Canadian Pacific Rail

Sources: *Coal Outlook*, 21:17, 21:19, 21:25, 21:29, 21:44, 21:46, and 22:33; *Coal Transportation Report*, 16:16; *Coal Week*, 23:19; *Journal of Commerce*, February 19, 1997.

[64] "A Whole New Way of Moving Coal," *Mining Voice* (March / April 1997), p. 9.

[65] H. J. Holcomb, "How to Break up Conrail in 14,810 Pages," *The Philadelphia Inquirer* (June 24, 1997).

[66] Electric Power Research Institute, *Fuel Management for Competitive Power Generation—A Guide to Managing Change*, TR-107890 (April 1997), pp. 4-8.

"Coal-by-wire" and tolling arrangements, as discussed above, offer new ways for coal producers, power generators, and power marketers to market their products in a competitive electricity market. If a reasonable rail rate is not available for its own plant, for example, a power generator may be able to send the coal to another plant and have the coal-generated electricity delivered through the transmission grid, reducing or saving coal transportation costs. It should be noted, however, that coal-by-wire is, to a great extent, limited by the availability of the transmission grid.

Summary

Electric power industry deregulation will open wholesale and, eventually, retail power sales to competition. Because coal is the major fuel used in electricity generation and electricity generators are the major consumers of coal, the coming changes will present a variety of challenges and opportunities to the coal industry.

Power generators will eventually be unbundled from the integrated electric utility structure and function as merchant plants, with no fixed customer base of present-day ratepayers. Competition among power generators will focus on price cutting and risk management. Attempts to cut prices will focus on fuel costs, the largest component of a power plant's production costs, which, in turn, will put pressure on coal prices. Power generators will not be willing to commit to new, long-term, fixed-price coal supply contracts, and they will seek to renegotiate existing high-price contracts to reduce fuel costs. Fluid electricity markets and increasing numbers of short-term coal transactions will increase the volatility of coal prices and the uncertainty of demand, requiring astute risk management by coal suppliers.

The coal industry has been cutting costs and consolidating production at both the mine and corporate levels for over a decade now. Electric power industry deregulation will continue, if not hasten, these processes. Productivity gains and cost reduction will result from improvements in technology, particularly the computerization of administrative tasks, as well as the use of bigger and more efficient mining machinery. Small firms, unable to take advantage of technological improvements and improve efficiency, will either go out of business or be bought out by larger firms, and large firms are likely to continue to increase in size through acquisitions of small firms or mergers with other large firms.

Coal industry financing will change dramatically under deregulation and will be a new challenge for coal producers, especially small producers who do not have large financial resources. The trend toward shorter contract durations and an uncertain customer base will lead financial institutions to evaluate coal mines on a "balance sheet" basis rather than the traditional "project financing," increasing the pressure on the industry to consolidate.

As coal contracts become shorter in duration and price volatility increases, risk management will be a crucial tool for coal producers to learn about and use in maintaining competitive viability. The most important development in this regard is the coming futures market in coal. Although coal's extreme variability in quality is a problem, NYMEX has one coal futures contract planned for Central Appalachian coal and is considering a Powder River Basin coal futures contract as well. Coal futures markets will not only allow risk hedging but also play the role of a coal price discovery mechanism. Other strategies for reducing risk include merging with other coal producers, creating alliances with customers (both railroads and power generators), vertical integration, and the formation of multi-fuel conglomerates.

The railroad industry, which will also figure prominently in any deregulation scenario, compounds the challenges faced by coal suppliers. Being the dominant carrier of coal, railroads can greatly influence coal transportation costs and, thus, the competitiveness of both coal producers and power generators. Of particular concern is that the increasing concentration of the railroad industry through consolidation may create the potential for the exercise of market power to extract large monopoly rents from coal shippers, with the possibility of changing the economics of coal production, distribution, and consumption at both the national and regional levels. On the other hand, the railroads may continue to lower their coal transportation rates through economies of scale and efficiency gains as they have done over the past years.

Deregulation will change the business relationships among coal producers, the railroads, and power generators. Coal producers may ally with railroads to provide delivered coal on a fixed schedule, allowing power plants to manage their inventories by less costly "just-in-time" methods. Coal producers and electricity generators may engage in profit- and risk-sharing alliances, such as coal tolling, a form of short-term alliance that allows plants to increase utilization rates and lower inventory costs. The strong incentives for the convergence of energy forms will expand to coal.