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The economics of coal production cycles in New Mexico

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Introduction

Since its beginning in territorial days, the New Mexico coal mining industry has experienced nearly three production cycles. If we have read all signals correctly, New Mexico is at or near the apex of the third such cycle. This report attempts to identify the economic and political factors that impact coal production and lead to these production cycles.

Coal has held a special status in the Western World since even before the beginning of the Industrial Age. Development and growth of an industrial economy and the advent of railroad and steamship transportation systems were the impetus for large-scale coal production, but coal had been previously used as a residential fuel, for minor smelting, metal-smithing operations, and simple forging. To a great extent, the Industrial Age was spawned and fueled by coal as a basic process fuel. Industry gave birth to world commerce, enriched cultures, the electrical age, and worldwide increases in standard of living. However, in the U.S. in a general way and particularly in New Mexico, coal production historically has been cyclical. It has not experienced a steady increase proportional to the fairly steady increase in industrial output. For example between 1920 and 1960, while the nation's output of goods and services increased several fold, New Mexico coal production declined overall.

Discussion

New Mexico coal production history, with the peaks of each cycle numbered, is summarized in Fig. 1. Production peaks 1 and 2 correspond with wartime economies. New Mexico participated in the national effort by supplying anthracite from the Cerrillos coal field to the U.S. Navy during World War I and bituminous coal to the Los Alamos Laboratories during World War II. By 1920 80% of the nation's energy needs were supplied by coal, and New Mexico had just experienced its first coal boom. Nationwide production peaked again in 1947, in New Mexico in 1943. The earlier peak and onset of decline in New Mexico has been attributed to a reduced labor pool—a result of the manpower demands of the war effort.

Production peak 3 is actually the culmination of a two-phase period of sustained growth. The first phase, initiated in 1962, was due to development of large strip mines by utility companies. The utility industry realized that natural gas and fuel oil prices would probably undergo a sharp upturn and consequently took the initiative of establishing itself in the coal-mining industry at a time ☞

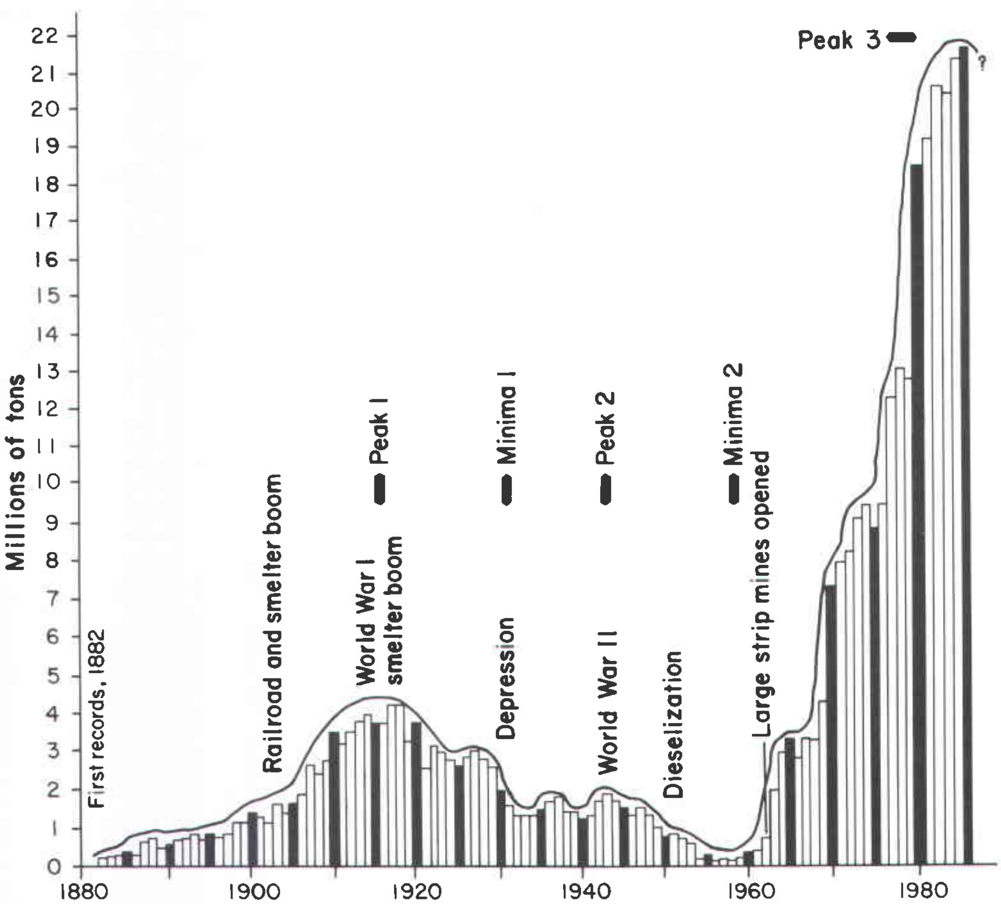

FIGURE 1—New Mexico coal production history (modified from Keystone Coal Industry Manual, 1981).

Also in this issue

Coming soon

Caldera-like collapse at Kilbourne Hole Maar
Mineral paragenesis, structure, and "ore-shoot" geometry at the U.S. Treasury mine
Harry McAdams State Park
Sedimentology of the Cutoff Formation, Guadalupe Mountains
Oil and gas discovery wells, 1986

TABLE 1—Fossil-fuel costs for electricity generation in the United States, 1965–1986 (cents per million Btu); * second quarter only (source: DOE/EIA, 1985a).

Year	Coal	Fuel oil	Gas
1965	24	33	25
1970	31	48	27
1971	36	56	29
1972	37	60	31
1973	41	80	34
1974	71	193	48
1975	81	203	75
1976	85	200	103
1977	95	226	129
1978	112	219	143
1979	122	308	175
1980	135	437	221
1981	153	539	282
1982	165	485	340
1983	166	459	347
1984	166	484	358
1985	165	432	343
1986	162*	224*	231*

when nationally the fuel-cost factor weighed in favor of natural gas (Table 1).

The second phase of growth leading to production peak 3 was stimulated by the Arab oil embargo in 1973 and the "energy crisis" that it produced. During and following that crisis many oil- and gas-fired boiler operations were cutback or scheduled for shutdown, and existing coal-fired plants operated at 100% of capacity while construction on new coal-fired facilities accelerated. During 1974 the Federal Energy Administration was actually given the power to order existing gas- and oil-fired electrical generating stations to revert to burning coal.

In the 1970's, as a result, 1) many new coal mines opened in the Powder River Basin of Wyoming, 2) the northeast Texas lignite fields were developed, 3) North Dakota's lignite reserves were developed, and 4) existing mines in New Mexico and Arizona were expanded (Fig. 2). There might have been even more rapid growth in coal usage during this time had there not been concern for the nation's air quality. It is important to note, however, that despite the growth in coal usage during the late 1970's, coal never did capture more than a 55% share of the utility fuel market, the amount that it had in 1955 (Fig. 3).

Thus the production maxima are fairly well understood. Not so well understood are the decline phases and production minima. Referring back to Fig. 1, we note that production minimum 1 coincided with the collapse of the stock market and the depression that followed. The gradual decline leading to minimum 1 reflects the post-WWI cooling of the economy, widespread unemployment, and the advent of natural gas usage on a local scale.

Production minimum 2 occurred in the 1950's and is associated with a burgeoning petroleum industry, which supplied low-cost natural gas through major regional pipelines to the utility industries and homes, and also to the fact that diesel fuel displaced coal as a railroad locomotive fuel. Coal production plummeted; the low was reached in New Mexico in 1958–59 when annual production dropped to 85,000 tons (New Mexico State Inspector of Mines, 1958). Nationally the low came somewhat later, during the 1972–73 period, and by this time the nation was relying on coal for only 18% of its energy needs (Lindbergh and Provorse, 1977). As the 1950's came to a close, petroleum imports had begun a steep climb. The stage was set for coal production in the western U.S. to enter a period of sustained growth that would span more than 25 years.

Current market factors

The four main factors that we believe will collectively shape the U.S. coal industry during the next 2–5 years are: 1) the declining U.S. industrial base as manifested by the shrinking steel, base metals, and auto industries; 2) the current world surplus of crude oil and ample domestic supplies of natural gas that allow fuel oil and gas to compete with coal on a cost/Btu basis; 3) the moderation in the growth rate of U.S. electrical consumption—in both residential and commerical sectors; and 4) the recent completion and coming on line of nuclear generating stations. A fifth factor is federal coal-leasing policy and other regulatory demands, which will probably have little effect in the short term, but may have greater impact in an extended time frame.

Of these five factors, the declining U.S. industrial base should cause the greatest concern because it has the greatest potential for coal market devastation, influencing both the steam-coal and metallurgical-coal markets. Manufacturing of an automobile requires about 10^8 Btu's—the energy contained in about 5 tons of coal (Tien et al., 1975). Actually the coal is first converted to electricity, a conversion process that is only 24% efficient. Thus, 20–22 tons of coal are ultimately required to manufacture each automobile. And it follows that the loss of 4 million vehicles a year to the import market translates into a reduction in coal demand of 88 million tons (if all the electrical energy required was generated with coal). Moreover, this represents 4 million days of labor if we use the productivity figure of 20 tons per man day, which in turn translates into 12,000–13,000 jobs in the coal industry alone.

Although factors 2 and 3 are justifiable concerns currently, surplus of crude oil and moderation in electrical energy demand can be reversed quickly in times of prosperity, bullish markets, and economic optimism. In addition, world crude oil surpluses can be

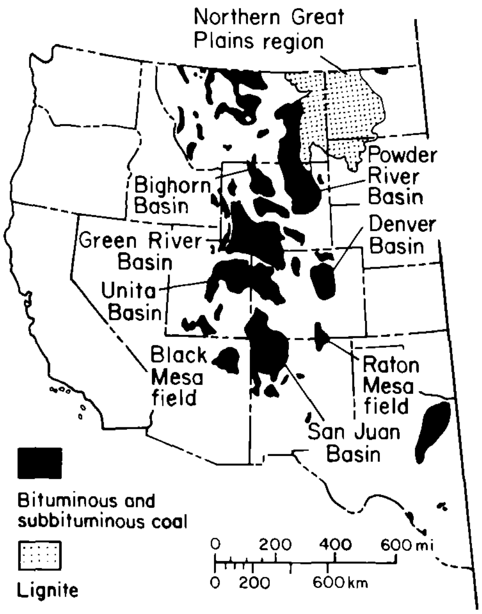

FIGURE 2—Coal fields of the western United States (after U.S. Geological Survey, 1960).

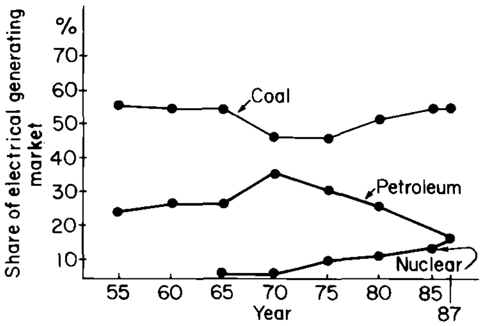

FIGURE 3—Fuels used in generation of U.S. electrical energy since 1955 (hydroelectric share not shown; after DOE/EIA, 1985b, p. 4).

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reversed easily by developments in the politically volatile Middle East. However, it is likely that further development of African, Asian, and Latin American oil fields, with or without new Arctic American or Canadian finds, will have a depressive effect on world oil prices for at least the next decade. Factor 4, nuclear capacity, will produce a short-term blip in the cycle, but does add to the down cycle of coal at present. This factor is short term because no new nuclear facilities are being planned or sited, and when the current inventory of stations under construction comes on line it will then become a fixed quantity in an expanding population, and we hope, economy.

Federal coal leasing policy

The fifth factor, federal leasing and regulation policy, is a controversial issue. We discuss only its economic impact and not the relative merits and intent. Any regulatory policy has negative economic impacts, but current coal-leasing policy contains economic disincentives for an already moderate-risk venture to the extent that federal coal lands are now almost a priori removed from consideration by the serious mining-industry investor. A major factor, the moratorium on leasing of federal coal, has been in effect anyway since 1971 (it was lifted from January 1981 to September 1983, but has been reinstated).

The salient economic points of the new federal coal leasing policy are: a) minimum bonus bids in the competitive bidding system, b) the diligent development and advance royalty clause, c) site specific environmental impact statements required for each mine that is subsequently opened, d) the required posting of reclamation bonds, and e) changing federal policy that itself creates corporate uncertainties about financial undertakings involving federal land. An additional point—the abolishment of the preference-right-lease system—is discussed under a separate heading. All of these factors have the effect of increasing the front-end capital required for any proposed mining operation. "Front-end" is the capital required to bring a mineral property to the point of production.

Other federal regulatory policies deal primarily with mine safety, mine drainage, and reclamation procedures such as timing, sequence, and end result. High safety standards are to be praised, but they come at a cost of reduced productivity (Fig. 4). Passage in 1969 of the Mining Safety Act ultimately was reflected in a 25% drop in productivity because more "unproductive" or "indirect" personnel were required in the mine. This had the effect of reducing our competiveness in the world export market. With respect to coal surface mines, reclamation and revegetation work is widely viewed as necessary, but in New Mexico this adds approximately $0.50 to the cost of each ton of coal produced (Tabet, 1977; Roybal and Eveleth, 1983). Roybal and Eveleth (1983) determined that reclamation will cost nearly $9,500/acre at one of New Mexico's active coal mines.

The coal research and data processing programs sponsored by the federal government, almost entirely through the U.S. Geological Survey, place a great deal of high quality information in the hands of industry and the interested public. These efforts include detailed geologic mapping and coal resource assessment work within the National Coal Resource Evaluation Program, and the computerized coal National Coal Resource Data System (NCRDS). However, basic research, coal resource data, and coal quality information are not limiting factors in the coal industry. Economics—market forces—determine and limit the rate of growth of this industry just as they do for all business endeavors in a free society. So, despite their ambitious data-gathering programs, the federal government's regulatory policies relating to coal leasing, development, safety, and reclamation will nonetheless add to the economic burden of the coal mining industry. It is worth noting that some government contractors are awarded contracts that specify "a-cost-plus-fair-return." This guarantees the contractor a profit. In contrast, potential developers of the raw materials of industry from U.S. owned lands are not accorded the same treatment.

The abolishment of preference-right leases

The preference-right-lease application (PRLA) system was abolished in 1977 in part because it was said to encourage speculation. Perhaps it did. However, obtaining a PRLA required that some exploration work be done, and this preleasing exploration work was financed by the private sector. Once the lease to a proven coal tract was obtained it became income-producing property for the U.S. government. Under the replacement system for PRLA's, the exploration work is financed by the taxpayer and leasing revenues are lost as the federal agency responsible goes about the business of detailed tract analysis so that it can eventually set a minimum bonus bid. The new system also places a prospective miner or developer at the mercy of bureaucratically collected data. Under the old (PRLA) system the mining industry evaluated its own data. Under the new system, the resource data that will be provided to prospective bidders is generated by the federal government. The old system wasn't all bad. Thomas Kleppe, former Secretary of Interior, recognized this in 1976 when he stated: "The federal exploration program contemplated in the coal leasing ammendment act of 1975 could be extremely costly (potentially billions of dollars) and would unnecessarily involve the federal government in an activity that can be better handled in the private sector" (Coal Age Magazine, 1976).

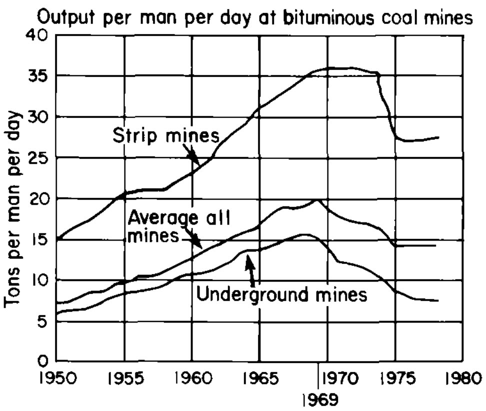

FIGURE 4—Coal productivity in U.S., 1950–1977; note that the Mine Safety Act was passed in 1969 (after Lindbergh and Provorse, 1977).

Fuel cost comparisons

It is instructive to examine recent trends and compare costs of boiler fuels and electrical-generation technologies. The fuels are fuel oil, natural gas, coal, and the alternative to these fossil fuels—isotopically enriched uranium. Table 2 lists the current delivered coal prices for selected southwest U.S. utility operations. While this cost-per-ton data is useful economic information for geologists and coal miners, cost-per-Btu data for fuel oil, gas, and coal are necessary for comparison. Table 3 compares 1973–1986 fuel data, and note that while coal has held a considerable price advantage over both fuel oil and natural gas, the price differential between coal and fuel oil narrowed significantly during 1985 and 1986. Cost of fuel oil had been as much as 10 times the cost of coal as a New Mexico electric utility fuel, but by mid-1986 it had dropped to approximately 1.6 times the cost of coal.

Natural gas prices have declined significantly also, especially since 1983 (Table 3), although not to the extent that fuel oil prices have dropped. New Mexico uses a relatively minor amount of natural gas in electrical generation, and far less fuel oil. The natural-gas-fired generating capacity is centered in the southeastern portion of the state, where very little fuel-switching capability exists. In the northwest, three major utilities have constructed coal-fired electric-generation facilities, and two of these have natural gas capacity at older, separate, plant locations that are maintained now as peaking stations. This peaking capacity is about 10% or less of the total generating capacity of the two utilities. Although the quantities involved in New Mexico are quite small, we see that fuel oil and natural gas costs compare closely with the national average (Table 1).

Because we are not presenting specific plant-fuel costs, the tables do not show that some major utilities in the state were able to purchase gas for 185¢ per million Btu by mid-1986. These are delivered costs of fuel and do not take into account such post-combustion factors as flue gas desulfurization, wet scrubbers, electrostatic precipitators, and ash removal/haul-back, all requirements that apply to coal use only. Therefore, the cost of delivered gas does not have to decline and ☞

TABLE 2—Delivered coal prices for some selected utility operations in southwest U.S. in 1986; * major participant in a consortium (from industry sources).

Supplier	Purchaser	Point of delivery	Cost/ton (dollars)
Arizona Public Service Co. Navajo mine (NM)	Arizona Public Service Co. Four Corners Generating Plant	mine–mouth generating plant	17.00
Public Service Co. of NM* San Juan mine (NM)	Public Service Co. of NM* San Juan Generating Plant	mine–mouth generating plant	24.00
Pittsburgh & Midway McKinley mine (NM)	Arizona Public Service Co.	Cholla Generating Plant near Winslow, AZ	31.00–32.00 (recent range 29.00–52.00)
Alamito Coal Co. (NM)	Salt River Project	Springerville, AZ	40.00 (recent range 23.40–45.15)
Spot market purchases	Salt River Project	St. Johns, AZ	43.00 (recent range 42.35–46.85)
Peabody Coal Co. Black Mesa mines (AZ)	Salt River Project	Navajo Generating Plant, Page, AZ (Lake Powell)	20.00 (recent range 18.80–22.40)

cross the coal price graph, it has only to approach, perhaps within 160 to 180%, the coal price in order to initiate some fuel switching. The switching is constrained by the fuel capabilities of the plants within a grid system.

The Department of Energy's viewpoint on the industry's fuel-switching capability follows (DOE/EIA, 1985b):

> . . . data suggest that the utility industry is, by and large, able to respond to shortages of specific fuels by switching to alternate fuels, at least in the short run. The options for switching, however, are primarily available for responding to coal strikes or natural gas shortages.

Fuel-switching capabilities are unique to certain regions. The northeastern U.S., the mid-Atlantic states, and California have considerable fuel oil to natural gas switching capabilities. On the other hand, the electric utilities in the Southwest and Rocky Mountain states, have only limited flexibility in switching from coal to natural gas, not at the same boiler but in the form of standby units called peaking stations. An interesting note on fuel options is that the Fuel Use Act of 1976 would prohibit the use of natural gas as an electric utility fuel by 1990. However, the Oil and Gas Production Revitalization Act introduced in Congress in January 1987 (H.R. 5596) contains a clause that would repeal the natural gas limitations set forth in the 1976 act. If this revitalization act is not passed, maximum flexibility in electric utility fuel options may be curtailed by government regulation within 2½ years.

Nationally, during the past 2 years, declining crude oil prices have made fuel oil available to utilities at much lower prices. As a result, fuel oil consumption increased by nearly 48% between mid-1985 and mid-1986, an increase confined largely to New England, the middle and south Atlantic states, and California. Fuel oil displaced natural gas as an electric-utility fuel in these areas, and consequently, the nationwide consumption of natural gas by utilities fell 8.3% during this time period (DOE/EIA, 1986). This in turn helped drive down the price of gas so that in certain regions, such as the southwest, a slight increase in gas usage was noted, initiating a trend opposite that of the nation. Overall, falling petroleum prices have had little impact on the fuel mix in the Four Corners and Rocky Mountain states where oil-fired plants account for less than 1% of installed capacity.

In mid-1986 U.S. electrical generating capacity by fuel type was as follows: coal, 54.3%; fuel oil, 5.2%; natural gas, 10.9%; nuclear power, 15.6%. Hydroelectric power accounted for virtually all of the remaining 14.0% (DOE/EIA, 1986).

New Mexico

Insulated as it is from the effects that declining petroleum prices can have on fuel mix at electrical generating plants, why is coal demand in New Mexico moderating and likely to decrease during 1987? One reason is that the major state utility (Public Service Company of New Mexico; PNM) designed its coal-fired plant with export capacity and for 20 years has sold power into the Southwest grid, including California. The southern California system left some of its natural-gas- and fuel-oil-fired plants idle and purchased the cheaper coal-generated electricity from New Mexico. This occurred under the late 1970's fuel price structure; under current fuel-price structure, fuel-oil- and natural-gas-fired plants are being operated at capacity, and electric power from coal generating plants in New Mexico is being refused.

The economics are this: although natural gas at the California plant may be 160–200% of the cost of coal at the New Mexico plant, the cost of electrical energy delivered to the California consumer from either plant will be about the same. This is due to the higher cost of operating the coal-fired plant and transmission line losses.

A significant cause for the softening coal demand at electric utilities in New Mexico during 1986–1987 was the commissioning of units no. 1 and no. 2 of the Palo Verde Nuclear Generating Plant 30 mi west of Phoenix. Unit no. 1 was authorized for full-power operation in 1985; unit no. 2, in April 1986. Each unit uses a pressurized-water reactor and can generate 1,270 megawatts. At present, total installed capacity there is 2,540 megawatts. A third 1,270-megawatt unit has begun receiving fuel and is scheduled to go into operation during the third quarter of 1987; Nuclear Regulatory Commission (NRC) authorization for full-power operation, barring any unforeseen circumstances, will be given by early 1988. The plant will at that time become the largest nuclear-generating facility in the United States. PNM has a 10.2% interest in the facility, but has opted for a sale-leaseback arrangement on units no. 1 and 2. However, it will begin accepting power from unit no. 3 late in 1987 and is entitled to 130 megawatts. Under the sale leaseback, PNM has the option of ultimately accepting 390 megawatts from Palo Verde. Whether the company exercises this option for the additional power depends on the economics of coal vs. nuclear, not load on the system.

PNM's excess capacity problem, in part due to currently low oil and gas prices, which are displacing part of the California market, is compounded by events in their own load region. The most important of these is the virtual disappearance of uranium mining and milling in the Grants uranium region; the uranium industry was one of their largest consumers of electrical energy, and indeed it appeared to be a thriving industry back in the 1973–1975 period when commitments were made to the Palo Verde Generating Station. Also, the utility has some overcapacity because of a slightly less than projected growth rate in demand in the private/residential sector.

Faced with this overcapacity, PNM will be forced to choose between continued operation of all four coal-fired units at the San Juan Generating Station west of Farmington or to accept their share of power from the Palo Verde Nuclear Plant. This decision will be an economic one, and it focuses our attention on the importance of nuclear-fuel procurement costs to New Mexico's coal mining industry and employment figures.

During late 1986 fuel costs for coal delivered at the San Juan Generating Station were in the 119¢ to 128¢ per million Btu range. Most recent cost estimates for nuclear fuel delivered to the Palo Verde plant are 79.8¢ per million Btu (Pers. comm., Media Relations Department, PNM, 1987). While there are additional operating costs at the plant that can moderate or increase this fuel cost advantage, these costs are not available. Construction and financing costs, however, far exceeded original estimates. Currently, it appears that this fuel-cost differential is going to be significant because plant-operating costs

TABLE 3—Fossil-fuel costs for electricity generation in New Mexico, 1973–1986; contract purchases only (in cents per million Btu); * month of May only (source: DOE/EIA, 1986).

Year	Coal	Residual fuel oil	Natural gas
1973	15	77	42
1974	19	159	58
1975	23	171	73
1976	26	184	91
1977	29	204	144
1978	42	219	164
1979	48	319	207
1980	56	545	247
1981	70	599	283
1982	78.5	580	322
1983	83.7	509	363
1984	93.4	541	349
1985	109.2	370.9	359
1986	102.8*	175.9*	314*

at Palo Verde are not expected to bring any surprises. The NRC has written a favorable report on the construction and operation of the plant.

The transmission system serving the Palo Verde plant has been completed under budget and is in operation. It was financed by and will be managed by the Salt River Project. Power will be distributed to the other utilities with part interest in Palo Verde—Arizona Public Service Company, Southern California Edison, Los Angeles Department of Water and Power, and El Paso Electric—several of which are among those who have already been by-passing New Mexico coal-generated power. If Palo Verde turns out to be a reliable source with a high plant capacity (the percentage of time it is on line), its 3,800 megawatts of power will obviously have an impact on the New Mexico coal industry.

PNM is currently evaluating the economics of the situation and will have an announcement by or before mid-1987. One alternative is to shut down one or more units at the San Juan plant, with a resulting reduction in capacity of 330–500 megawatts. This would correspond with a decrease in coal consumption of at least 1.7 million tons per year. Depending on whether or not any new coal markets are developed, this scaleback could change the coal-mining growth curve New Mexico has enjoyed for 27 years. Or, as we indicated in Fig. 1, the production fall off may be of such magnitude and duration that the peak of cycle no. 3 will emerge by the end of 1987. The state has already lost one coal mining operation during the last half of 1986: Carbon Coal Company at Gallup, New Mexico. Their only customer, Arizona Electric Power Cooperative, shut down all the coal-fired generators at the Apache station during August and September 1986, and began buying power from the Southwest grid. The Palo Verde plant is, of course, part of this grid. Any scaleback in operations at the Arizona Public Service Company's Four Corners Generating Station or at the Cholla plant near Joseph City, Arizona, would, of course, only exacerbate the coal market condition, but these stations have been base-loaded since their inception.

On the positive side for the mining industry is the ultimate intention of the Salt River Project (Arizona) to expand a pilot coal-stripping operation in the Salt Lake coal field (west-central New Mexico) into a commercial stripping operation. The open-pit mine would be developed in the Moreno Hill Formation (Upper Cretaceous), and the coal would be transported by truck 70 miles to the Coronado Generating Plant near St. Johns, Arizona, while the feasibility of a railroad is studied. Production at the new site could more than offset the production losses due to the shut down of Carbon Coal, but would not compensate for the potential scaleback at the San Juan plant. However, the long-term cost effectiveness of this Salt Lake coal mine is uncertain.

Summary and outlook

Optimism on the part of the U.S. coal mining industry has to be tempered by 1) continuing decline of the U.S. industrial base and 2) continuing low to low–moderate crude oil and natural gas prices, which encourage fuel-switching in the electric utility industry. Both these factors have had a greater effect thus far on the nation at large than they have had on New Mexico and the Four Corners states. This is because of the very limited industrial/manufacturing base in the Southwest (excluding California), the very limited fuel-switching capacity of the electric utility industry in this region, and almost nonexistent fuel-oil-fired capacity.

Impinging directly upon the New Mexico coal industry and threatening to interrupt a 27-year period of continuous growth, are developments in the uranium and nuclear-fuel industries. These are 1) the decline and virtual demise of the uranium mining/milling industry in this state, which was a large consumer of electrical energy and 2) the completion of units 1 and 2 of the Palo Verde Nuclear Generating Plant near Phoenix and the expected completion in the third quarter of 1987 of unit no. 3. PNM has a 10.2% interest in the plant and will begin accepting power from unit no. 3 following start-up later in 1987. This interest represents excess capacity for PNM, and thus the company will end up with some fuel-switching options. Currently fuel-procurement costs favor the nuclear facility by a significant margin, but there are some plant operation costs yet to be determined.

Federal coal-leasing policy does not have immediate, short-term implications for the New Mexico coal industry. The policy does have long-term implications because such a significant percentage of the state's strippable coal is on federal land, and interested bidders will be forced to look at federal coal leases eventually. The leasing policy contains many provisions that tend to increase front-end capital requirements and consequently become a disincentive to leasing. It is significant to note that the last three coal mines to open in the state of New Mexico have been on privately owned land.

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U.S. Geological Survey, 1960, Map of coal fields of the United States, 1 sheet.

Geographic Names

U.S. Board on Geographic Names

Cieneguilla Creek—stream, 23.3 km (14.5 mi) long, heads on west slope of Agua Fria Peak at 36°21′51″N, 105°13′18″W, flows west and north to Eagle Nest Lake, 7.4 km (4.6 mi) north–northeast of Agua Fria; Colfax County, NM; 36°30′02″N, 105°15′42″W; USGS map of Eagle Nest, scale 1:24,000.

Comanche Pass—pass, in the Manzano Mountains at the head of Comanche Canyon 9.7 km (6 mi) west–northwest of Torreon; Torrance County, NM; 34°44′20″N, 106°24′15″W.

Tusas Mountains—mountains, 80 km (50 mi) long and 32 km (20 mi) across, extend north–northwest from Ojo Caliente between Tres Piedras on the east and Tierra Amarilla on the west to a point 12.9 km (8 mi) northeast of Chama; Rio Arriba County, NM; 36°59′30″N, 106°29′00″W (northwest end), 36°18′00″N, 106°04′00″W (southeast end); *not:* Brazos Mountain Range.