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Informal Report

Rocky Mountain Coal for Southern California's Coal-Fired Electric Power Generation

University of California

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Rocky Mountain Coal for Southern California's Coal-Fired Electric Power Generation

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CONTENTS

ROCKY MOUNTAIN COAL FOR SOUTHERN CALIFORNIA'S COAL-FIRED ELECTRIC POWER GENERATION

by

Orson L. Anderson

ABSTRACT

This report is a scaled-down version of a "Study of Alternative Locations of Coal-Fired Electrical Generating Plants to Supply Western Coal to the Department of Water Resources." It covers three aspects of the major report: (1) coal resources in the Upper Colorado Plateau, (2) the possible transportation of those coal resources to southern California, and (3) the cost analyses of the coal transportation. Descriptions of 92 coalfields within an 800-mile radius of the Los Angeles energy market are included. The general legal regulations governing the acquisition and development of coal from state, federal, and private lands are discussed. This report also describes the existing and potential methods of transporting the coal to southern California.

I. INTRODUCTION

A recent comprehensive report was issued on proposed coal-fired electrical power plants in California by the Institute of Geophysics at the University of California, Los Angeles (UCLA) to the California State Department of Water Resources (DWR), entitled "Study of Alternative Locations of Coal-Fired Electrical Generating Plants to Supply Western Coal to the Department of Water Resources," hereafter called the DWR report.

The DWR report was assembled and edited from a number of separate reports prepared in support of the study by professors, students, and staff from four campuses of the University of California, including Los Alamos Scientific Laboratory (LASL). Many LASL staff were involved in this study, and much of their work will appear as separate LASL reports.

Those aspects of the DWR report involving (1) coal resources in the Upper Colorado Plateau, (2) the possible transportation of those coal resources to southern California, and (3) the cost analyses of the coal transportation are issued in this report. This compilation and the production of this aspect of the DWR report were supported in part by a contract between LASL and UCLA, involving the services of Orson L. Anderson, Consultant to LASL and principal investigator of the DWR report. This is the final report for the LASL-UCLA contract.

We describe 92 coalfields within an 800-mile radius of the Los Angeles energy market. Of these, 69 coalfields are eliminated from consideration as long-term suppliers of energy to the southern California area of power at the level of 100 MW or above. The 17 remaining coalfields are in Wyoming, Colorado, Utah, New Mexico, and Arizona. For each of these, a detailed report is made of the location, topography and climate, history, transportation and population, geology and deposits, quality, resources, mineability and production costs, resource ownership, and prospective future development. The general legal regulations governing the acquisition and development of coal from state, federal, and private lands are discussed.

We describe the existing and potential methods of transporting the coal to southern California from the 17 coalfields, with special attention to the problem of transporting coal from the Kaiparowits coalfield. These methods include existing railroads, potential railroads, potential slurry pipelines, and electrical transmission lines. A section on the legal constraints regarding rights-of-way for the various Western States and for Indian lands is included.

Power plant sites in the general southern California desert region were chosen because of a number of legal, political, and regulatory factors (Chap. 2, DWR report). Specific siting in the southern California desert region was focused on those areas that met standards on air quality, water availability, and environmental impact controls (Chap. 2, DWR report). For example, sites had to be 12 miles away from the nearest topographic relief greater than 2000 ft. Five sites were chosen in the general areas near Barstow, Cadiz, Goffs, and Rice in the Mojave Desert, and Blythe in the Colorado Desert (see Fig. 1-1).

Three areas outside California were selected for cost comparison purposes and because they are attractive for other reasons. Parker Valley, Arizona, is convenient and entirely within the Colorado River Indian Reservation (Fig. 1-1). It is thus subject to certain legal controls, especially concerning Colorado River water allocations. The Price-Green River region in eastern Utah was selected because it is being examined as a possible industrial-energy corridor by state and industry officials. It has favorable transportation factors for coal shipment as well (Fig. 1-2). Central White Pine County, near Ely, Nevada, was selected because of its water-supply potential and potential community enthusiasm for such a plant (Fig. 1-3).

In the computations, the electric transmission is between the plant and Edmonston, California, which is the site of the electric pumps of the California Water Project.

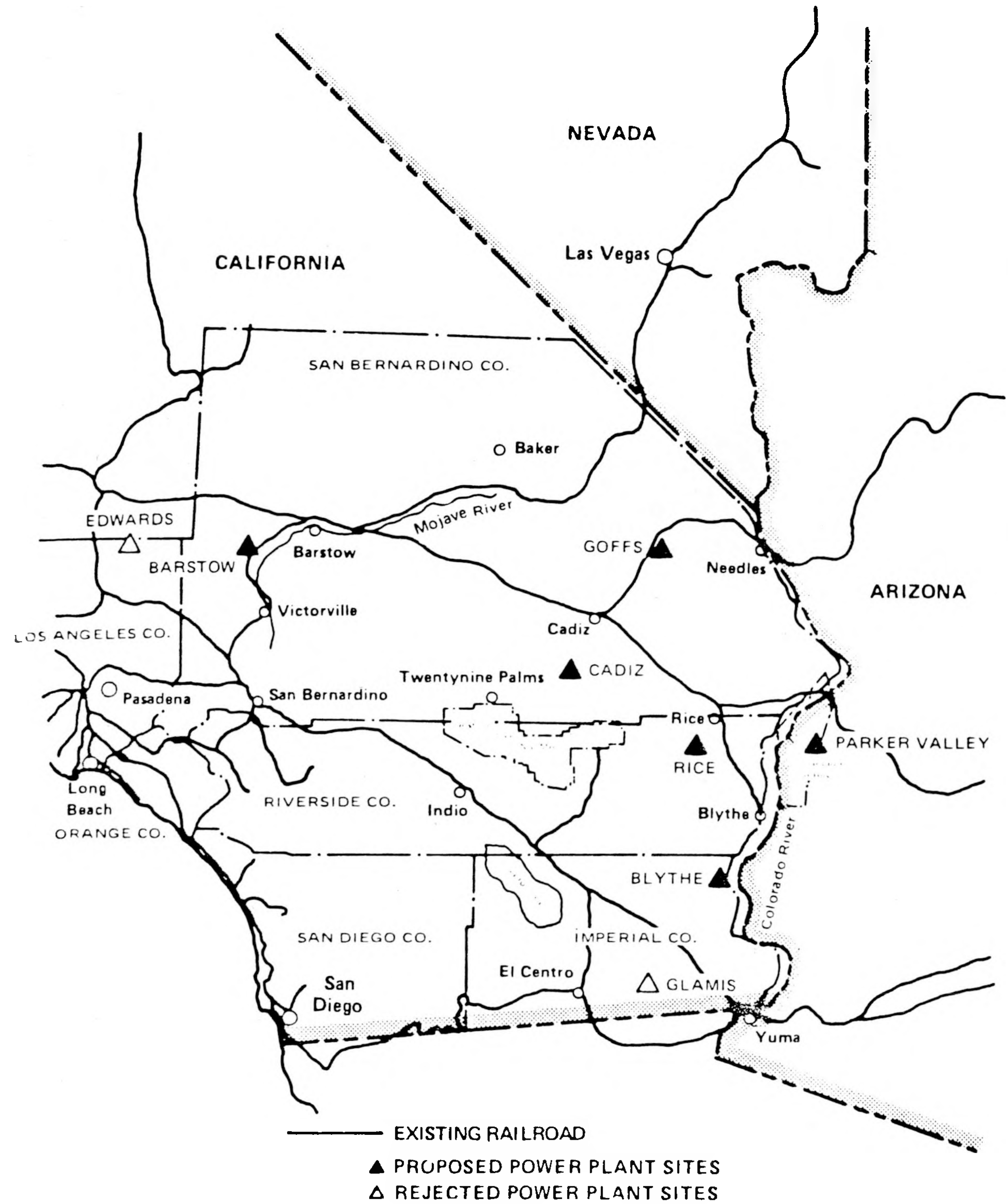


Fig. 1-1.
Proposed California and Arizona power plant sites.

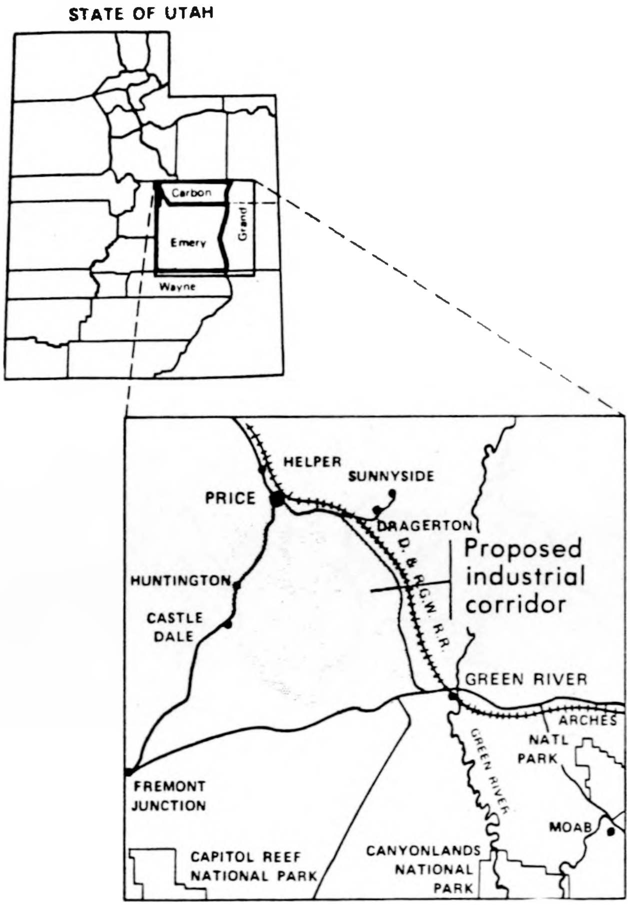


Fig. 1-2.
Proposed industrial corridor in Utah as a possible power plant site.

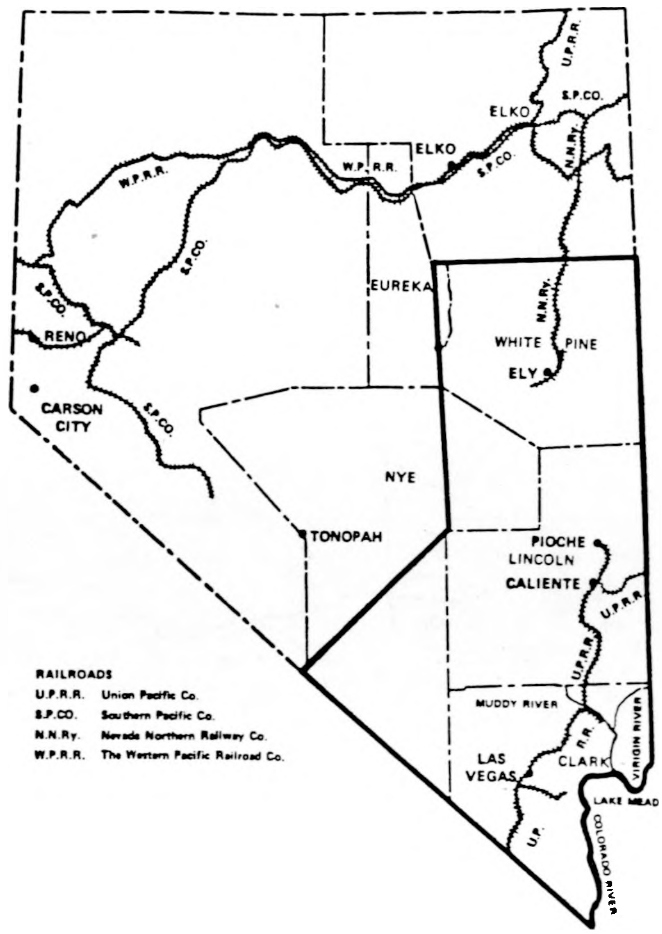


Fig. 1-3.
White Pine County as a possible power plant site.

2.1. Introduction[1]

2.1.1. Origin of Coal. Coal is "a readily combustible rock containing more than 50% by weight and more than 70% by volume of carbonaceous material, including inherent moisture, formed from compaction and induration of variously altered plant remains similar to those in peat."[2] The plants or plant fragments that eventually became coal accumulated in ancient fresh or brackish water marshes or swamps by growing in these environments or by being transported there by erosional processes. Two criteria were necessary to form a good coal deposit: a warm, humid environment that produced a great abundance of plant life, and a basin in which the plant remains could accumulate.

As the plant material continued to collect, the lower layers were slowly compacted and turned into peat.[3] The greater the amount of plant remains deposited in the swamp, the thicker the peat bed, and thus the resulting coal bed, will be. Very thick coal beds, characteristic of some Western States, require a very long period of optimum plant growth conditions accompanied by a nearly stable geologic period of very slow land subsidence.[4] In time, environmental conditions changed and the peat-forming basin was covered by marine deposits from a transgressing sea or by river-deposited sands and gravels. The process could have been repeated many times, giving rise to a sequence of coal seams, interbedded with sandstones and shales, but eventually the conditions conducive to the formation of peat disappeared and the material was buried under the thickening accumulation of sediment.

Coalification is the process by which the compacted peat is turned into coal, and it describes both the chemical and physical alterations of the peat. As the peat was buried deeper, both the pressure from the overlying sediments and temperature from the geothermal gradient rose, and the peat began to compact and devolatilize even further.[5] The deeper the burial or the longer the time spent buried, the more dense and devolatilized the coal will eventually become.

2.1.2. Classification of Coal. Coal is classified by any one of three properties. (1) degree of coalification or metamorphism (rank), (2) degree of impurity (grade), and (3) constituent plant materials (type).

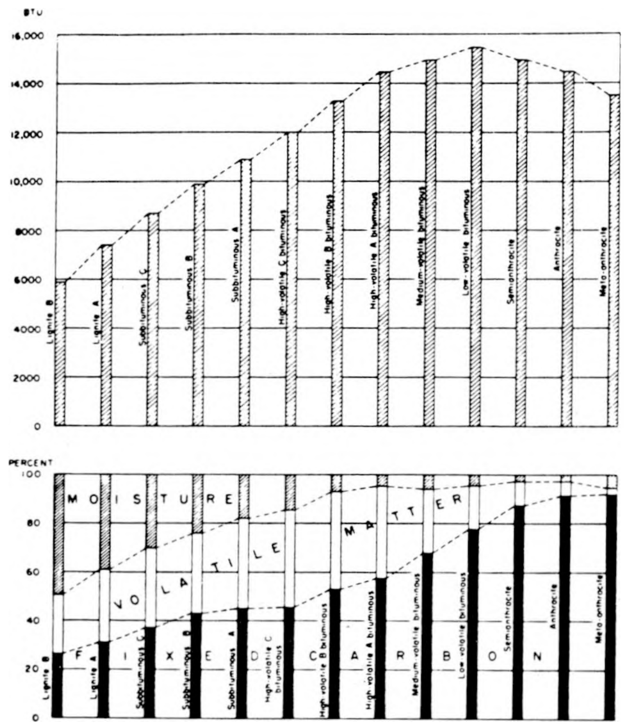


Fig. 2-1.
Variation of heat content, moisture, volatile matter, and fixed-carbon in coals of increasing rank. (Source: Jack A. Simon and M. E. Hopkins, "Geology of Coal," 1973. (See Ref. 4.)

Coal rank is determined by the variations in the percentages of fixed carbon (and volatile matter) and heat content based upon a mineral-matter-free basis as shown in Fig. 2-1 (see Table 2-1).[6] Thus the coal rank increases from lignite B to high-volatile A bituminous coal as the heat content increases from 6300 to 14 000 Btu per pound of most coal. Coal ranks from medium-volatile bituminous to meta-anthracite are determined by the increasing percentage of fixed-carbon over volatile matter. Both progressions are basically a result of increasing depth of burial, increasing temperature, and increasing burial time, therefore coal rank is a parameter of coal that is fairly consistent regionally. Thus, in general, the greater the geologic age of a coal deposit the higher in rank that coal will be. The

TABLE 2-1

CLASSIFICATION OF COALS BY RANK[a]

Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis) Equal or Greater Than	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis) Less Than	Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis) Greater Than	Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis) Equal or Less Than	Calorific Value Limits, Btu per Lb (Moist,[b] Mineral-Matter-Free Basis) Equal or Greater Than	Calorific Value Limits, Btu per Lb (Moist,[b] Mineral-Matter-Free Basis) Less Than	Agglomerating Character
I. Anthracitic	1. Meta-anthracite	98	---	---	2	---	---	Nonagglomerating
	2. Anthracite	92	98	2	8	---	---	
	3. Semianthracite[c]	86	92	8	14	---	---	
II. Bituminous	1. Low-volatile bituminous coal	78	86	14	22	---	---	Commonly agglomerating[e]
	2. Medium-volatile bituminous coal	69	78	22	31	---	---	
	3. High-volatile *A* bituminous coal	---	69	31	---	14 000[d]	---	
	4. High-volatile *B* bituminous coal	---	---	---	---	13 000[d]	14,000	
	5. High-volatile *C* bituminous coal	---	---	---	---	11 500	13,000	
						10 500	11,500	Agglomerating
III. Subbituminous	1. Subbituminous *A* coal	---	---	---	---	10 500	11,500	Nonagglomerating
	2. Subbituminous *B* coal	---	---	---	---	9 500	10,500	
	3. Subbituminous *C* coal	---	---	---	---	8 300	9,500	
IV. Lignitic	1. Lignite *A*	---	---	--	---	6 300	8,300	
	2. Lignite *B*	---	---	---	---	---	6,300	

[a]This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free Btu per lb.

[b]Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c]If agglomerating, classify in low-volatile group of the bituminous class.

[d]Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e]It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high-volatile C bituminous group.

coals in the Eastern United States are of Carboniferous Age [340 to 280 million years (Myr) old], and are thus of higher rank (bituminous and anthracite) than the Cretaceous and Tertiary (135 to 22 Myr old) coals of the Western United States, which are primarily lignite to high-volatile bituminous.

The grade of coal is a way of expressing that coal's quality. It is usually quite independent of the rank of the coal. The grade of a coal describes its content of deleterious constituents such as sulfur, ash, and trace elements. Although regional classification of coal resources by sulfur is being attempted, the ash, trace elements, and even sulfur vary greatly even within any one coal seam. Thus quality averaging over any large area is difficult. Coal quality has a very direct influence on the environmental impact of coal burning.

Coal rank, quality, and type combine to determine the uses to which a certain coal can be put. The two largest users of coal in the United States are electric power utilities and the metals industry. The latter group, which includes iron and steel producers, uses coal to fire furnaces and to reduce iron ore to metallic iron. For these purposes the metals industry requires the higher rank (anthracite and bituminous) coals and those coals that will coke.[7] Electric power utilities have been concerned primarily with the cost of the coal per Btu, and therefore they most often used the lower grade coals. Now, however, with much more stringent regulations on allowable emissions from coal-fired power plants, utilities are increasingly looking toward cleaner coals. These coals are not only less abundant and thus higher priced, but are also often the coals that are needed by the metallurgical industry. Coking coals are even less abundant than high-quality noncoking coals.

2.1.3. Coal Deposits in the United States. The coal deposits of the United States are classified by location into a descending hierarchy: (1) coal provinces, (2) coal regions, (3) coalfields, and (4) coal areas or districts.

Figure 2-2 shows the coal deposits in the six coal provinces of the United States. Coal provinces are major groups of coal deposits based upon geologic age, geologic structural setting, quality, and location. Coal within parts of the westernmost three (Pacific Coast, Rocky Mountain, and Northern Great Plains) coal provinces have been examined for this study. Coal regions are groups of coalfields having some geomorphic or geographic relationship.

Coalfields are generally separated from one another and usually have some special geographic or coal-quality characteristics. The coalfield is the unit of coal deposits used within this study. Coal districts or areas are the smallest subdivisions and represent areas of concentrated mining activity or coal development.

The quantity of coal in these deposits depends upon the criteria used in making the determinations. The classification system adopted by both the United States Geological Survey (USGS) and the United States Bureau of Mines (USBM) segregates coal deposits into two categories: reserves and resources.[8] (See Table 2-2.) Coal resources are the total estimated quantity of coal in the ground within the region of estimation. The coal reserve is that small portion of the total coal resource that has been reasonably identified and can be economically recovered at the time of determination. (Because not all the coal is recovered during mining, the coal reserve, also called the recoverable reserve, is only a percentage of the reserve base, i.e., that coal identified and economically mineable but not necessarily recoverable.) Coal deposits are thus described by both their degree of geologic identification and their degree of economic or technologic feasibility of recovery.

Table 2-3 gives the total identified and hypothetical coal resources of the United States. Table 2-4 breaks down the demonstrated reserve base of the United States by state and by potential mining method. Only 44% of the total estimated coal resources are identified, and only 11% compose the United States reserve base. About 5.5% [219 000 million tons (Mtons)] is in the demonstrated economically recoverable category.[9]

2.1.4. United States Coal Production. Figure 2-3 shows the annual production of bituminous and lignite coal in the United States from 1950 through 1974 by mining method. Table 2-5 lists these figures for the years 1969 through 1974. Although production declined from 595.4 to 591.7 Mton between 1972 and 1973, it increased to 601.0 Mton in 1974. Greatest production in any one year was the 631 Mton mined in 1947, and cumulative United States production through 1973 was over 40 billion tons (Bton).[10] Coal demand exceeded coal supply througnout 1973.[11] Figure 2-4 graphs the trends in coal production, capacity, and value per ton since 1950.

Coal production in the United States has been greatly influenced by the shifting energy requirements of the nation. Between 1947 and 1961, coal's contribution to the total United States energy demand dropped from 43.5% to 21% because of the increased availability of oil and gas and because of the decrease in coal use by the railroads.[12] Since that time there has been a tremendous growth in coal consumption by electric utilities. This increased demand is one of the reasons for the dramatic rise in average US coal prices shown in Fig. 2-4. Table 2-6 compares 1969 through 1973 average prices for total US coal production and coal produced by strip and underground mining.

Methods of production have changed greatly since coal was first stripped in about 1915. Table 2-7 shows the percentage of total United States coal production mined by stripping since 1915. The largest increase was between 1969 and 1971 when strip mining production gained 12 percentage points to 47%. Significantly, 1974 was the first year that more coal was mined by stripping than by underground methods. Since 1969, the year the Federal Coal Mine Health and Safety Act was passed, many small underground mines have been forced to close, decreasing total coal production capacity.[13] The Act

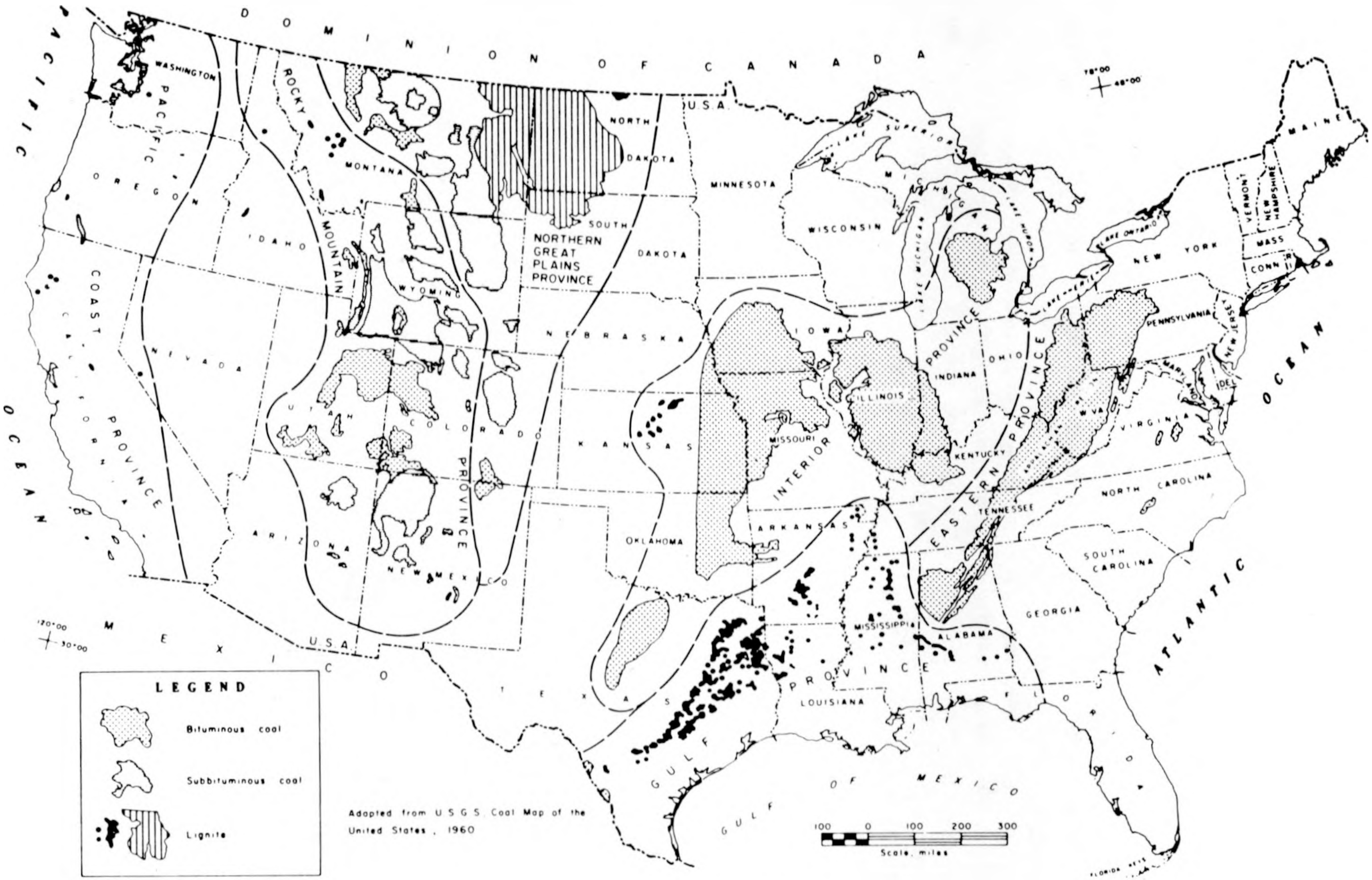
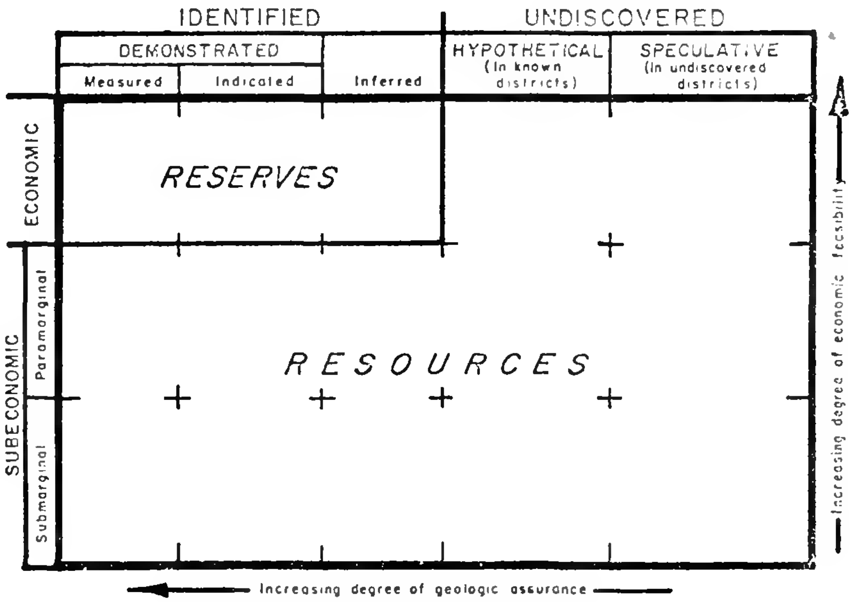


Fig. 2-2.
Coal provinces and deposits of the United States. (Source: Ref. 1, Fig. 1-4, pp. 1-35.)

TABLE 2-2

JOINT US GEOLOGICAL SURVEY AND US BUREAU OF MINES CLASSIFICATION OF TOTAL MINERAL RESOURCES



Resource - A concentration of coal in or on the earth's crust in such form that economic extraction is currently or potentially feasible.

Identified resources - Specific bodies of coal whose location, quality, and quantity are known from geologic evidence supported by engineering measurements with respect to the demonstrated category.

Undiscovered resources - Unspecified bodies of coal surmised to exist on the basis of broad geologic knowledge and theory.

Reserve - That portion of the identified coal resource that can be economically mined at the time of determination—also referred to as **Recoverable Reserve**. The reserve is derived by recoverability calculations from that component of the identified coal resource designated as the reserve base.

Identified-Subeconomic resources - Coalbeds that are not Reserves, but may become so as a result of changes in economic and legal conditions.

Paramarginal - The portion of Subeconomic Resources that (a) borders on being economically producible or (b) is not commercially available solely because of legal or political circumstances.

Submarginal - The portion of Subeconomic Resources that would require a substantially higher price (more than 1.5 times the price at the time of determination) or a major cost-reducing advance in technology.

Hypothetical resources - Undiscovered coalbeds that may reasonably be expected to exist in a known mining district under known geologic conditions. Exploration that confirms their existence and reveals quantity and quality will permit their reclassification as a Reserve or Identified-Subeconomic resource.

Speculative resources - Undiscovered coalbeds that may occur either in known types of deposits in a favorable geologic setting where no discoveries have been made, or in as yet unknown types of deposits that remain to be recognized. Exploration that confirms their existence and reveals quantity and quality will permit their reclassification as Reserves or Identified-Subeconomic resources.

The following definitions for measured, indicated, and inferred are applicable to both the Reserve and Identified-Subeconomic resource components.

Measured - Coal for which estimates of the quality and quantity have been computed, within a margin of error of less than 20 percent, from samples analyses and measurements from closely spaced and geologically well-known sample sites.

Indicated - Coal for which estimates of the quality and quantity have been computed partly from sample analyses and measurements partly from reasonable geologic projections.

Inferred - Coal in unexplored extensions of Demonstrated resources for which estimates of the quality and size are based on geologic evidence and projection.

TABLE 2-3

TOTAL ESTIMATED COAL RESOURCES OF THE UNITED STATES January 1, 1972

Figures in millions of short tons for resources in the ground, about half of which may be considered recoverable. Includes beds of bituminous coal and anthracite ~14 in. thick and beds of subbituminous coal and lignite ~2 1/2 ft thick.

Identified Resources[a]					Hypothetical Resources[b]			Total Resources
Overburden 0-3000 ft					Overburden 0-3000 ft	Overburden 3000-6000 ft	Total Overburden 0-6000 ft	Overburden 0-6000 ft
Bituminous coal	Subbituminous coal	Lignite	Anthracite	Total	Resources in unmapped and unexplored areas			
747 357	485 766	478 134	19 662	1 730 919	1 849 649	387 696	2 237 345	3 968 264

[a]Identified resources: specific, identified mineral deposits that may or may not be evaluated as to extent and grade, and whose contained minerals may or may not be profitably recoverable with existing technology and economic conditions.

[b]Hypothetical resources: undiscovered mineral deposits, whether of recoverable or subeconomic grade, that are geographically predictable as existing in a known district.

(Source: Paul Averitt, 1975; "Coal Resources of the United States, January 1, 1974." *U.S. Geological Survey Bulletin 1412* (Washington: U.S. Gov't. Print. Off.), Table 3, p. 14-15.)

also increased the cost of underground mining for those mines remaining open, leading to a total increase in coal prices and an accelerated shift to strip mining.

2.2. Preliminary Coal Source Identification

2.2.1. Area of Analysis. The ultimate sink for the possible coal-generated power evaluated in this study was assumed to be southern California. As such, every coalfield within a reasonable distance of the sink must be considered as a possible source. (Coalfields were selected as the initial unit of investigation because of their relative ease of identification.) In selecting an outer limit to the area of investigation, consideration was made of the possibility of moving the coal energy from source to sink by either electric transmission lines (generating electricity at the source) or by actually moving the coal. A circle 800 miles in radius from Los Angeles was selected as the outer limit of feasible coal sources because that distance is toward the outer limit of economic electric transmission distances and also includes all major coalfields west of the Continental Divide (south of Washington) and all fields south of the 43rd Parallel (with three exceptions). This area encompasses 92 individual coalfields within the Pacific Coast, Rocky Mountain, and Northern Great Plains coal provinces.

Significant areas of coal resources not evaluated as part of this analysis include the Denver region, Colorado; the Wind River region, Wyoming; the Bighorn Basin and Powder River Basin regions, Wyoming and Montana; and the Fort Union region, Montana, North Dakota, and South Dakota. Very significant coal deposits, many of which are strippable, underlie these large areas, but all are far from a southern California market and are of comparatively low quality.

The area of analysis, as shown in Figure 2-5, includes all coalfields within California, Nevada, Arizona, Utah, and New Mexico, and nearly all in Oregon, Idaho, and Colorado. Slightly under half of the coalfields in Wyoming are also included.

Coal production within this area totaled 33.4 Mton in 1973, and 46.4 Mton in 1975. Table 2-8 shows the 1973 total by state and by production method. The differences in methods of production between states is obvious: Utah produces over half of the deep-mined coal and none of that stripped, while New Mexico and Wyoming together strip half the coal produced in the area yet deep-mine only 17%. Over all, strip mining accounts for 72% of the area

TABLE 2-4

DEMONSTRATED RESERVE BASE OF COALS[a] IN THE UNITED STATES ON JANUARY 1, 1974

State	Anthracite		Bituminous		Subbituminous		Lignite	
	Under.	Surface	Under.	Surface	Under.	Surface	Surface	Total
Alabama	---	---	1 798	157	---	---	1 027	2 982
Alaska	---	---	---	1 201	4 246	5 902	296	11 645
Arizona	---	---	---	---	---	350	---	350
Arkansas	96	---	306	231	---	---	32	665
Colorado	28	---	9 227	870	4 745	---	---	14 870
Georgia	---	---	1	---	---	---	---	1
Illinois	---	---	53 442	12 223	---	---	---	65 665
Indiana	---	---	8 949	1 674	---	---	---	10 623
Iowa	---	---	2 885	---	---	---	---	2 885
Kansas	---	---	---	1 388	---	---	---	1 388
Kentucky, East	---	---	9 467	3 450	---	---	---	12 917
Kentucky, West	---	---	8 720	3 904	---	---	---	12 624
Maryland	---	---	902	146	---	---	---	1 048
Michigan	---	---	118	1	---	---	---	119
Missouri	---	---	6 074	3 414	---	---	---	9 488
Montana	---	---	1 384	---	64 450	35 464	7 098	108 396
New Mexico	2	---	1 527	250	607	2 008	---	4 394
North Carolina	---	---	31	[b]	---	---	---	31
North Dakota	---	---	---	---	---	---	16 003	16 003
Ohio	---	---	17 423	3 654	---	---	---	21 077
Oklahoma	---	---	860	434	---	---	---	1 294
Oregon	---	---	---	[b]	1	[b]	---	1
Pennsylvania	7 030	90	22 789	1 091	---	---	---	31 000
South Dakota	---	---	---	---	---	---	428	428
Tennessee	---	---	667	320	---	---	---	987
Texas	---	---	---	---	---	---	3 272	3 272
Utah	---	---	3 780	262	---	---	---	4 042
Virginia	138	---	2 833	679	---	---	---	3 650
Washington	---	---	251	---	1 195	500	8	1 954
West Virginia	---	---	34 378	5 212	---	---	---	39 590
Wyoming	---	---	4 524	---	24 997	23 845	---	53 366
Total	7 294	90	192 334	40 562	100 211	68 070	28 163	436 725

[a]Includes measured and indicated categories as defined by the USBM and USGS and represents 100% of the coal in place.

[b]Less than 1 Mton.

Source: U.S. Bureau of Mines. Demonstrated Coal Reserve Base of the United States on January 1, 1974. Bureau of Mines Mineral Industry Surveys, May 1975.

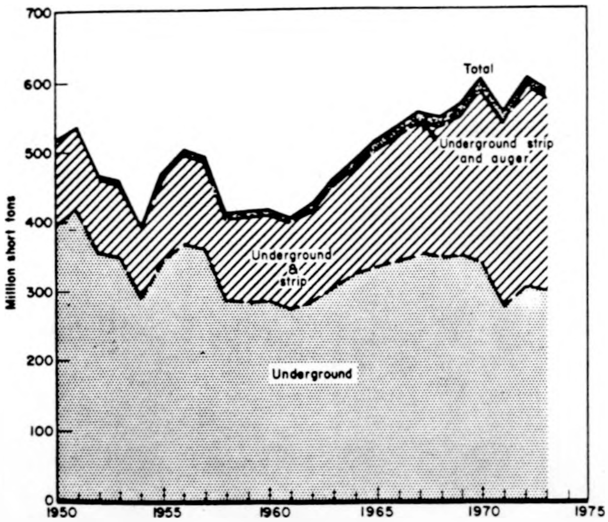


Fig. 2-3.
Production of bituminous coal and lignite, by type of mining, in the US, 1950-1974. (Source: Ref. 11, Fig. 1, p. 325, with 1974 production from Ref. 1, Table 1-9, p. 1-41.)

production. The largest deep mine in the area produces slightly over 1 Mton per year; most strip mines produce up to 7 Mton per year.

2.2.2. Governing Assumptions. The major criterion for this analysis is total cost minimization. Total cost includes not only the basis capital and operating costs, but also time, legal, political, social, and environmental costs. Straightforward costs include resource ownership, exploration, mine development, mine operation, coal quality and benefaction, reclamation and transportation costs (see Appendix A2 for a discussion of coal mining operations and facilities). Time delays at any stage can increase all these costs. Legal and political constraints, as well as social and environmental considerations, again can reflect increased time delays and added financial costs. The legal constraints to coal development and production are covered in Secs. 2.3 and 2.4. The factors considered most important in a preliminary selection of probable coal sources were individual field total recoverable reserves, proximity to transportation, coal quality, and mineability and development status. Appendix B2 lists all 92 coalfields, in order of increasing radial distance from Los Angeles, and tabulates data in each of the above categories.

Initial assumptions included the amount of coal required: a 1000-MWe power plant will consume about 3 Mton of coal per year, or up to 100 Mton of coal over a 35-yr lifetime. Taking into consideration the costs of resource exploration, mine development, and transportation development, it was assumed that the total coal requirement would come from only one field, although not necessarily from only one mine. Thus, recoverable reserves in excess of 100 Mton must be available from any one field to be considered feasible. Because coalfields often cover very large areas, an even larger recoverable reserve is desirable.

Transportation will be a critical factor in determining which coal sources can be economically exploited for use in southern California. This factor becomes less critical in looking for coalfields to supply mine-mouth power plants, although mining and construction materials and equipment still must be transported to the site. Railroads are by far the most common method of transporting coal over these distances (400 miles or more) in the West where navigable rivers are essentially nonexistent. The closer a potential coal source is to southern California the less expensive its transport will be, although some closer coalfields have no ready access to rail lines, and coal from others must travel a circuitous route to reach southern California. Those fields greater than 25 miles from an existing railway and requiring more than 1100 miles of transportation were rejected. The exceptions were those fields close enough to southern California to make a coal slurry pipeline economically feasible, and those fields that lie along any of the newly proposed rail extensions in the study area (see Sec. 3.1.2).

Low coal quality in itself was not usually a criterion for rejection but figured in determining how desirable was the coal from that field. Lower coal quality usually interprets directly into higher costs. Low heat value will increase the costs of transportation since more weight must be moved to obtain a specified energy content. Even low-sulfur coal will most likely exceed current SO_2 emission standards upon burning, unless the stack gases are scrubbed, and the higher the sulfur content the more scrubber waste, expensive to dispose of, is produced. High-ash content also creates increased environmental problems from a greater emission of fly ash and the costs of disposing of greater quantities of ash collected by precipitators.

TABLE 2-5

UNITED STATES PRODUCTION OF BITUMINOUS COAL AND LIGNITE BY PRODUCTION[a] METHOD, 1969-1974

	1969[b]	1970[c]	1971[d]	1972[e]	1973[f]	1974[g]
Total Production	560 505	602 932	552 192	595 386	591 738	601 000
Underground Mining	347 130	338 788	275 888	304 103	299 353	273 800
Strip Mining	197 023	244 117	258 972	275 730	276 645	311 530
Auger Mining	16 350	20 027	17 322	15 554	15 739	15 670

[a]Thousands of short tons.

[b]L. W. Westerstrom, 1972, "Coal-Bituminous and Lignite." In U.S. Department of Interior, Bureau of Mines, *Minerals Yearbook 1970, Vol. I, Metals, Minerals, and Fuels* (U.S. Govt. Print. Off., Washington), p. 328.

[c]1972. *Minerals Yearbook 1970,* p. 341.

[d]1973. *Minerals Yearbook 1971,* p. 334.

[e]1974. *Minerals Yearbook 1972.* p. 338.

[f]1975. *Minerals Yearbook 1973,* p. 327.

[g]Ref. 1, Table 1-11, p. 1-41.

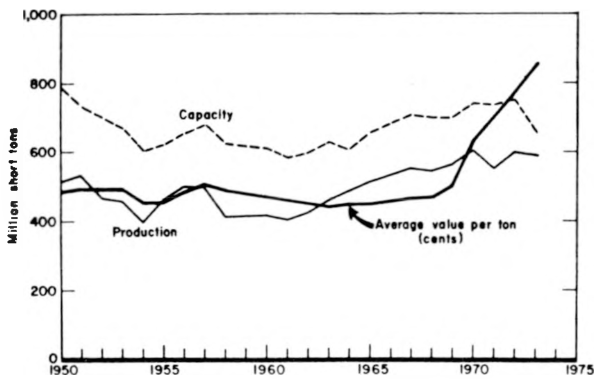


Fig. 2-4.
Trends of bituminous coal and lignite production, realization, and mine capacity in the US, 1950-1973. (Source: Ref. 11, Fig. 2, p. 326.)

Mineability and development considerations are the most important yet difficult-to-analyze factors in determining the cost of coal production. Major factors used to guide selection of the possible coal sources included the type of coal, production methods, difficult geologic conditions, the extent of information available about each deposit, and land ownership. Coal of coking quality was rejected as a power plant fuel because of its high cost and demand in the metals industry. Coal that can be recovered by stripping is now much less expensive to produce than coal from underground mines. In underground mining, exceptional geologic conditions can greatly increase production costs. Lenticular, thin, split, thick, or multiple seams are all more expensive to mine and result in lower total reserve recoverability. Structural factors such as faults, folds, and steeply

TABLE 2-6

UNITED STATES AVERAGE COAL PRICES,[a] 1969-1973

	1969[b]	1970[b]	1971[c]	1972[d]	1973[d]
Underground Mining			$8.87	$9.70	$10.84
Strip Mining			5.19	5.48	6.11
All Production	$4.99	$6.26	7.07	7.66	8.53

[a]F.O.B. Mines per short ton for all U.S. production of stated type.

[b]L.W. Westerstrom, 1972. "Coal-Bituminous and Lignite." In U.S. Department of Interior, Bureau of Mines, *Minerals Yearbook 1970, Vol. I, Metals, Minerals and Fuels* (U.S. Govt. Print. Off., Washington), p. 327.

[c]1974. *Minerals Yearbook* 1972, p. 329.

[d]1975. *Minerals Yearbook* 1973, p. 318.

TABLE 2-7

COAL PRODUCTION BY STRIP MINING AS A PERCENTAGE OF TOTAL UNITED STATES PRODUCTION

5-Year Intervals, 1915-1970		Annually, 1960-1974	
Year	Percentage	Year	Percentage
1915	<1	1960	30
1920	2	1961	30
1925	3	1962	31
1930	4	1963	31
1935	6	1964	31
1940	9	1965	32
1945	19	1966	34
1950	24	1967	34
1955	25	1968	34
1960	30	1969	35
1965	32	1970	40
1970	40	1971	47
		1972	46
		1973	47
		1974	52

Calculated from Ref. 1, Table 1-9, p. 1-40 to 1-41; and Table 2-5 in this section.

dipping beds result in similar losses. Mining of deep reserves results in increased engineering and safety costs and lower recoverability.

The extent of information available for the deposit is critical in determining both the time and cost required to develop that coal reserve. In fields with only minimal information about the coal reserves, an extensive program of exploration and development will be required to determine the existence and recoverability of any deposits. Fields that are better explored and understood will require proportionately less time and effort to develop. In areas that have already undergone extensive mining the problems of development and production will be well understood. Last, a few fields were deemed less favorable because of their control by agents now opposed to the development of the reserves.

2.2.3. Initial Results. Table 2-9 lists all 69 coalfields from Appendix A2 that have been eliminated from consideration as probable coal sources. The second column also lists the rejection criteria. Almost half (32) the coalfields were immediately rejected because of insufficient reserves. The others were eliminated by multiple problems, the most common being no or poor transportation

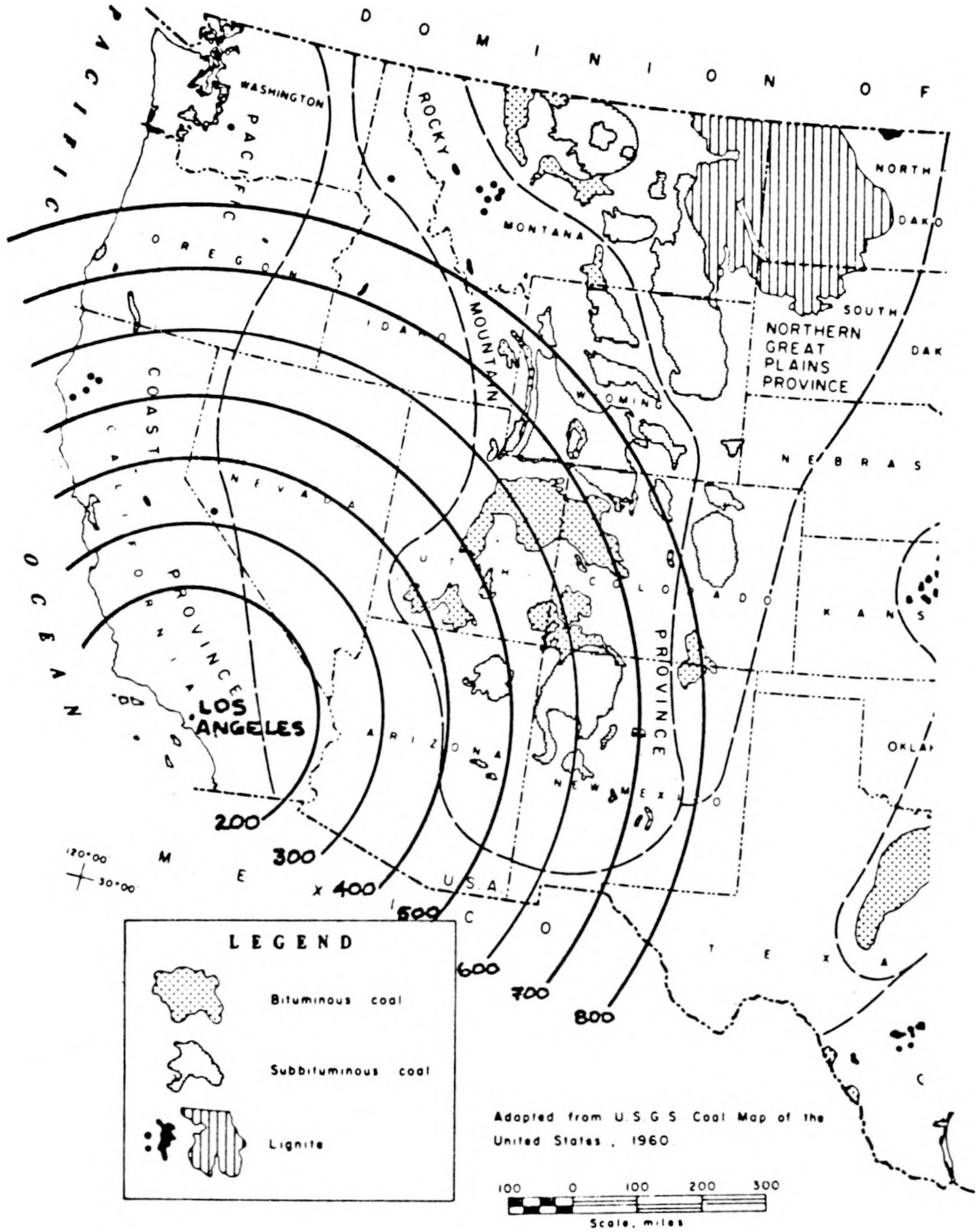


Fig. 2-5.
Boundaries to the area of analysis.

TABLE 2-8

COAL PRODUCTION[a] IN STUDY AREA BY STATE, 1973

State	Underground			Strip			Total		
	Mines	Quantity	% of State Total	Mines	Quantity	% of State Total	Mines	Quantity	% of Area Total
Arizona	0	NP[b]	0	1	3 247	100	1	3 247	10
California	0	NP	0	0	NP	0	0	NP	0
Colorado	19	2 851	50	8	2 834	50	27	5 685	17
Idaho	0	NP	0	0	NP	0	0	NP	0
Nevada	0	NP	0	0	NP	0	0	NP	0
New Mexico	1	733	8	5	8 336	92	6	9 069	27
Oregon	0	NP	0	0	NP	0	0	NP	0
Utah	16	5 500	100	0	NP	0	16	5 500	16
Wyoming	3	418	4	6	9 477	96	9	9 895	30
Total	39	9 502	28	20	23 894	72	59	33 396	100

[a]Production figures are in thousands of short tons.

[b]No Production.

Calculated from Ref. 11, Table 18, pp. 339-345.

(24), difficult mining/poor quality (21), and little information (15).

Table 2-10 lists the 17 coalfields or field groups that remain as possible coal sources. This table groups them into six geographical units and lists both their major advantages and disadvantages. Figure 2-6 displays these fields in their positions along the railroads in the Southwest. Section 2.5 of this report presents a more detailed analysis of each of these coalfields.

2.3. General Regulations Governing the Acquisition and Development of Coal

2.3.1. Coal from Federal Lands. A substantial portion of the available coal located in the five western states under consideration as sources (Colorado, New Mexico, Utah, Wyoming, and the Navajo Reservation in Arizona) is under federal control.[14] Federal law provides for the leasing of these reserves pursuant to the 1920 Mineral Leasing Act[15] and accompanying federal regulations.[16] Although scattered leasing had already taken place, the vast majority of lease acquisitions on federal lands has occurred since 1965.[17] Because it became evident that widespread speculation and little development were taking place,[18] the Department of the Interior in 1973 initiated a moratorium[19] on issuance of further leases under most conditions.[20] Both administrative[21] and legislative[22] reconsideration of federal regulations and policy concerning coal leasing is now going on and is likely to alter significantly past estimates concerning the availability of this resource in the near future.

In the past, coal leases were most frequently obtained by first acquiring a "prospecting permit,"[23] which would be matured into a preference-right lease upon a showing that coal in "commercial quantities" existed.[24] In the few areas deemed "known coal leasing areas," a system of competitive bonus bidding was employed instead.[25] Under either system, however, coal leases were framed to give a right in perpetuity; although their terms were subject to review at 20-yr intervals, the continuance of the lease did not depend on commencing and continuing production of the mineral, as is the practice with oil and gas leases. Fairly low rates of royalty[26] were set, to be paid only upon production;[27] minimal rental payments[28] were also required during the period before production was undertaken. Development was supervised by the USGS[29] and procedures were expected to comply with USGS regulations concerning environmental damage.[30] Acreage limitations also limited the amount of land that could be held under a single lease[31] and the total acreage in a single state held by any one individual or company.[32]

Although companies who acquired federal coal leases in the past undoubtedly did so with the expectation that these rather undemanding provisions would stay in force, most of the leases in question contained stipulations either that the lessee is subject to regulations "now or hereafter in force" (leases signed since January 1964) or that "reasonable diligence in operations" is required, although no reference is made incorporating future regulations (leases signed from October 1956 to January 1964).[33] For the more recent leases (including most of those relevant here), therefore, changes in federal regulations will have immediate effect;[34] for those somewhat older, a requirement of diligent development can at least be enforced once it has been defined.[35] For even older leases, changed regulations will be given effect, at the very least, when they next come up for review.

The Bureau of Land Management (BLM), which is responsible for such leasing arrangements, has already taken steps to effectuate such changes. Regulations first proposed in late 1974, then revised on the basis of comments received and submitted for comment once again in December 1975,[36] were finally approved on May 25, 1976, with an effective date of June 1, 1976.[37] The new provisions reinvigorate the requirements of diligent development and continuous production established under the 1920 Act. Although allowing developers slightly greater leeway by applying these standards to "logical mining units" (LMU),[38] which may contain both federal and nonfederal coal, rather than single leases, the regulations provide, on pain of cancellation,[39] that during a period of 10 yr from the date of the new regulations (the date of the lease would be used if it were later), 1/40 (2.5%) of the LMU reserves associated with that lease be extracted.[40] A single 5-yr extension in meeting this time requirement would be available in three situations:[41] (1) when time is needed to complete development of advanced technology (e.g., in situ gasification or liquefaction); (2) when the project is one of peculiarly large magnitude (a mine in production in the first year after the end of the extended period for diligent development is expected to be at least 2 Mton if an underground mining operation, or 5 Mton if a surface mining operation); or (3) if a contract or equivalent firm commitment *exists* for the sale or use of the first 1/40 of the LMU reserves by the end of the 5-yr extension.

A second significant change would require "continuous operation": "extraction, processing, or marketing of coal in the annual average amount of 1% or more of the LMU reserves[42] in each year after diligent development has been achieved." In lieu of continuous operation, a lessee may pay, beginning with the sixth year after the issuance of the lease, an annual advance royalty on a minimum number of tons determined on a schedule designed to exhaust the leased reserves in 40 yr from the effective date of these regulations (or the date of the lease if later).[43] Such a revision in existing royalty obligations would appear to take effect only on the next 20-yr review of existing leases.[44] The due-diligence requirement of initial production may well be interpreted to have immediate effect, however,[34,35] forcing at least some existing lessees to produce, commit themselves to firm contracts, or let their interests lapse within the next 10 yr. Indeed, the next regulations contain a reaffirmation of the Department of the Interior's power to cancel leases if there is no compliance with this obligation.[39]

The above discussion relates primarily to existing leases. Other changes in federal regulations would alter the manner in which leases could be acquired in the future. In January 1976, Interior Secretary Kleppe announced the end of the moratorium on leasing begun in 1973, but indicated that in the future the prospecting permit/preference-right

TABLE 2-9

REJECTED COAL SOURCES

Field or Area	Rejection Criteria
Stone Canyon, California	Insufficient reserves.
Coaldale, Nevada	Do.
Ione, California	Do.
Harmony, Utah	Do.
Kolob, Utah	Very poor quality, difficult mining.
Henry Mountains, Utah	No transportation.
Pinedale, Arizona	Insufficient reserves.
Deer Creek, Arizona	Do.
Goose Creek, Utah	Do.
Tabby Mountain, Utah	Do.
Mt. Pleasant, Utah	Deep reserves, no production.
Wales, Utah	Insufficient reserves.
Sterling, Utah	Do.
Salina Canyon, Utah	Do.
San Juan, Utah	Do.
La Sal, Utah	Do.
Nucla-Naturita, Colorado	No railroad, little exploration, very isolated.
Cortez, Colorado	Low reserves, no transportation.
Durango, Colorado	Poor quality, long transportation.
Barker Creek, New Mexico	No transportation, Navajo jurisdictional issues.
Fruitland, New Mexico	No rail transportation.
Hogback, New Mexico	No transportation, Navajo jurisdictional issues.
Navajo, New Mexico	Do.
Todalena, New Mexico	Do.
Newcomb, New Mexico	Do.
Zuni, New Mexico	Low reserves, poor transportation, difficult mining.
Datil Mountain, New Mexico	Low reserves, difficult mining.
Coos Bay, Oregon	Insufficient reserves.
Eden Ridge, Oregon	Do.
Rogue River, Oregon	Do.
Horseshoe Bend, Idaho	Do.
Lost Creek, Utah	Insufficient reserves.
Coalville, Utah	Do.
Henrys Fork, Utah	Do.
Henrys Fork, Wyoming	Do.
Vernal, Utah	Do.
Lower White River, Colorado	No transportation, no production.
Grand Mesa, Colorado	Poor transportation, low production.
Tongue Mesa, Colorado	Poor transportation, no production.
Monero, New Mexico	Poor transportation, very little exploration.
Tierra Amarilla, New Mexico	Insufficient reserves.
La Ventana, New Mexico	Little exploration, thin seams.
Chacra Mesa, New Mexico	Poor quality, difficult mining, little exploration.
East Mount Taylor, New Mexico	Do.
South Mount Taylor, New Mexico	Do.
San Mateo, New Mexico	Do.

Field or Area	Rejection Criteria
Rio Puerco, New Mexico	Little exploration, poor transportation.
Cerrillos, New Mexico	Insufficient reserves.
Uña Del Gato, New Mexico	Do.
Tijeras, New Mexico	Do.
Carthage, New Mexico	Do.
Jornada del Mureto, New Mexico	Very little exploration, thin seams.
Engle, New Mexico	Do.
Teton Basin, Idaho	Little exploration, poor transportation.
Greys River, Wyoming	Insufficient reserves.
McDougal, Wyoming	No transportation, low reserves.
Jackson Hole, Wyoming	Do.
La Barge Ridge, Wyoming	Insufficient reserves.
Kindt Basin, Wyoming	Do.
Danforth Hills, Colorado	No transportation.
North Park, Colorado	Do.
Middle Park, Colorado	Insufficient reserves.
South Park, Colorado	Do.
Crested Butte, Colorado	Poor transportation, difficult mining.
Canon City, Colorado	Low reserves, long transportation.
Walsenburg, Colorado	Poor transportation, coking quality.
Trinidad, Colorado	Do.
Raton, New Mexico	Do.
Sierra Blanca, New Mexico	Poor transportation, difficult mining.

system would no longer be employed.[45] Instead, the development of federal coal is to be shaped by the new Energy Minerals Activity Recommendation System (EMARS) outlined in the final federal coal leasing programmatic Environmental Impact Study (EIS).[46] Under this system, the Federal Government will take much more initiative than in the past and leasing will become much more systematic. It is therefore unlikely that any further largely uncontrolled blossoming of private rights in federal coal such as occurred in the late 1960s will take place in the future.

Recent federal legislation that would significantly affect the future of coal development in this country should also be noted. In June 1976, the Senate finally adopted the House's version of a revision to the 1920 Mineral Leasing Act,[47] thereby conceding that its own measure,[48] passed in July 1975 and containing extensive provisions with regard to strip mining on public lands, could not be enacted successfully this term. The resulting bill, S. 391, was vetoed by President Ford on July 3, but passed over the President's veto on August 3 in the House (316-85) and on August 4 in the Senate (76-17).[49] The new law would change the term of coal leases to 20 yr and so long thereafter as coal is produced in commercial quantities; leases not producing in such quantities after 10 yr would be terminated.[50] The conditions of diligent development and continuous operation would be maintained but are defined somewhat more stringently than in the new Interior Department regulations, for advance royalty payments could be accepted in lieu of continuous operations for only 15 yr.[51] Logical mining units would also be recognized.[52]

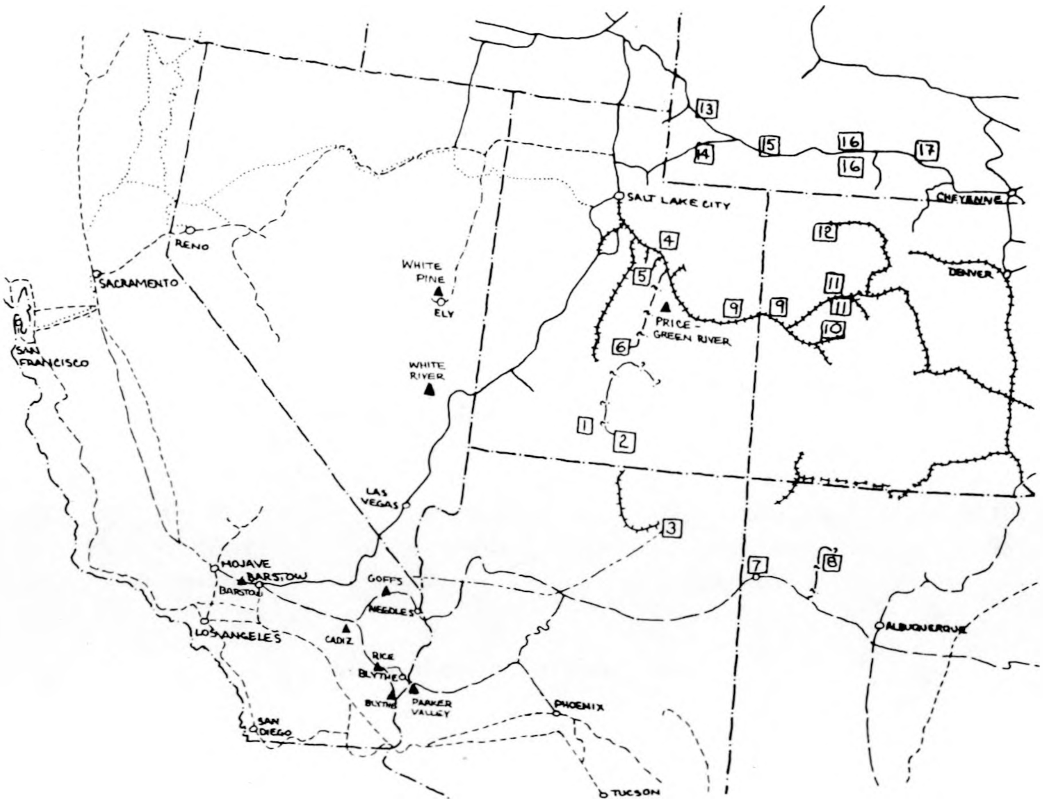
Royalties would be set at a rate of not less than 12-1/2% of the value of the coal,[53] and all leasing would be done by competitive bidding.[54] In an effort to spur development while providing for more careful regulation than has occurred in the recent past, the

TABLE 2-10

POSSIBLE COAL SOURCES

Field or Field Group	Advantages/Disadvantages
Southwestern Utah and Arizona Fields	
(1) Alton, Utah	Good reserves, close, slurry possible, some strippable, fair quality. No rail transportation, no production, committed?
(2) Kaiparowits, Utah	Abundant reserves, close, slurry possible, generally good quality. No rail transportation, no production, difficult access.
(3) Black Mesa, Arizona	Close to sites, slurry possible, good quality, much strippable, existing leases. Very poor rail transportation, Indian jurisdiction.
Central Utah Fields	
(4) Book Cliffs, Utah	Very good transportation, large producer, good quality. Expensive, heavy overburden mining, expensive to buy?
(5) Wasatch Plateau, Utah	Fair to good quality, fair to good transportation. Difficult, expensive mining.
(6) Emery, Utah	Untapped reserves, proposed railroad. Moderate quality, expensive mining.
New Mexico Fields	
(7) Gallup, New Mexico	Strippable reserves, very good transportation, producing. Fair quality, expensive?
(8) Star Lake, New Mexico with portions of the following:	Abundant stripping reserves, proposed rail line. Little information, high ash.
Bisti, New Mexico	Very abundant stripping reserves, proposed rail. Poor quality, possibly poor transportation.
Chaco Canyon, New Mexico	Near proposed railroad route, strippable. Poor quality, little exploration.

Field or Field Group	Advantages/Disadvantages
Standing Rock, New Mexico	Strippable, along proposed rail line, good quality. Thin, lenticular seams, little information.
Crownpoint, New Mexico	Along proposed rail line. Poor quality, thin, lenticular seams.
Western Colorado Fields	
(9) Sego, Utah, and Book Cliffs, Colorado	Good quality, good seams. Moderate reserves, no mining now. Large untapped reserve, fair quality. Largely unknown, fair transportation.
(10) Somerset, Colorado	Abundant reserves, large producer, good quality? About 1/2 coking, fair transportation.
Northwestern Colorado Fields	
(11) Grand Hogback, Colorado, and Carbondale, Colorado	Fair quality, untapped reserve. Fair transportation, some mining problems. Abundant reserves, large operations. Coking, poor quality, fair transportation.
(12) Yampa, Colorado	Abundant stripping reserves, lots of mines. Long transportation, quality varies.
Southern Wyoming Fields	
(13) Kemmerer, Wyoming	Some strippable, fair to good quality and transportation. Highly faulted and folded, some cokable.
(14) Evanston, Wyoming	Very good quality? Fair to good transportation. Moderate reserves; faulted and folded?
(15) Rock Springs, Wyoming	Moderate distance, strippable seams? High reserves. Moderate quality.
(16) Great Divide, Wyoming, and	Appreciable stripping reserves, some production. Long transportation, quality varies.
Little Snake River, Wyoming	Appreciable stripping reserves, some production. Long transportation, quality varies.
(17) Hanna, Wyoming	Good quality, extensive strippable reserves, extensive production. Very long rail transport.



Southwestern Railroads and Coalfields

<u>Selected Possible Powerplant Sites</u> ▲

<u>Railroads</u>

Atchison, Topeka and Santa Fe
Denver and Rio Grande Western
Nevada Northern
Southern Pacific
Union Pacific
Western Pacific
Black Mesa and Lake Powell
Proposed Extensions
Black Mesa Coal Slurry Pipeline

<u>Coalfields</u>

I. Southwestern Utah and Arizona
- 1 Alton, Utah
- 2 Kaiparowits Plateau, Utah
- 3 Black Mesa, Arizona

II. Central Utah
- 4 Book Cliffs, Utah
- 5 Wasatch Plateau, Utah
- 6 Emery, Utah

III. New Mexico
- 7 Gallup, New Mexico
- 8 Star Lake, New Mexico (Includes portions of: Bisti, New Mexico; Chaco Canyon, New Mexico; Standing Rock, New Mexico; Crownpoint, New Mexico)

IV. Western Colorado
- 9 Sego, Utah and Book Cliffs, Colorado
- 10 Somerset, Colorado

V. Northwestern Colorado
- 11 Grand Hogback, Colorado, and Carbondale, Colorado
- 12 Yampa, Colorado

VI. Southern Wyoming
- 13 Kemmerer, Wyoming
- 14 Evanston, Wyoming
- 15 Rock Springs, Wyoming
- 16 Great Divide, Wyoming, and Little Snake River, Wyoming
- 17 Hanna, Wyoming

Fig. 2-6.
Southwestern railroads and coalfields.

bill also reduces the period of time between readjustment periods from 20 to 10 yr,[55] introduces exploration licenses in lieu of prospecting permits while requiring all licensees to submit collected data to the Secretary of the Interior,[56] limits national holdings controlled by any person, corporation, or association to 100 000 acres on federal coal lands,[57] and requires an examination of all proposed leases for possible antitrust violations.[58] Of particular significance is the provision barring the issuance of additional leases to anyone who has held a federal coal lease for a 15-yr period without producing coal in commercial quantities;[59] it undoubtedly serves as a tool to create further pressure on current lessees to produce or relinquish their holdings.[60]

Although this legislation is directly aimed at revising the terms under which coal is leased in the future, its effect on existing leases must also be considered. The House Committee report states that:

> Old leases (those existing on the date of enactment of the 1975 Act) would be exempt from this provision (automatic termination after 10 years in the absence of production), except to the extent it might be made applicable upon readjustment of lease terms, but the lessees would be prohibited from acquiring any new Federal leases should they continue to hold old leases 15 years after enactment without producing therefrom. Additionally, each lease will be subject to diligent development and continued operation.[61]

This language unfortunately appears somewhat contradictory in application. It indicates that absent modification at the time of the 20-yr readjustment of terms, existing leases are not to be automatically terminated for nonproduction after 10 yr; at the same time, however, it suggests that the diligent development and continuous operation requirements that existed even under the 1920 Act, and which have been clarified by the new departmental regulations, should apply to such "old" leases. Although the provisions are conceptually related, this seeming inconsistency can best be reconciled by regarding the flat termination provision as separate from the due-diligence requirement. The revised due-diligence requirement would then apply to existing leases to the extent it is incorporated under their terms; it would have immediate effect where the lease so states but in other cases would not be brought into play until the next readjustment period.[62] Under this reading, the new law would have its greatest effect on future leasing; the departmental regulations, which do not appear to be superseded by S. 391,[63] would most immediately influence development of existing leases.

2.3.2. Coal from Indian Lands. Legal constraints on the lease of Indian lands differ considerably from those applicable to other federal lands. Under the Omnibus Tribal Leasing Act of 1938,[64] mineral interests in unallotted lands[65] may, with the approval of the Secretary of the Interior, be leased for terms of up to 10 yr and so long thereafter as minerals are produced in paying quantities.[66] The Bureau of Indian Affairs' regulations[67] provide much more detailed information concerning the leasing procedure. Two possible avenues are available. (1) Competitive bidding or negotiation.[68] Lease tracts are technically to be no larger than 2560 acres, but exceptions are permitted where larger acreage is in the interest of the lessor and is necessary to permit the establishment or construction of thermal electrical power plants or other industrial facilities on or near the reservation.[69] (2) Royalty must be at least \$0.10 per ton,[70] and rental at least \$1 per acre;[70] a yearly development expenditure of \$10 per acre is also required.[71] Additional obligations may be imposed as part of the consideration for the lease.[72]

The political realities are apt to provide more potential worries than any formal legal limitation. Although the Navajo tribal leadership at present favors continued development of the reservation's coal resources, unhappiness caused by the dislocation of many families as a result of past strip mining is also evident.[73] As a result, the possibility of a changing tribal stance either during or after the completion of negotiations with respect to further exploitation of tribal resources should be recognized.[74]

2.3.3. Coal from State Lands. Federal land grants to each state at the time of admission generally included all swamp and saline lands plus specific allotments for public buildings and a university. But the bulk of the land granted to each state consisted of entire named sections, the second, sixteenth, thirty-second, and thirty-sixth of each township, or the nearby equivalent where these were not available, which were to be devoted to the support of the common schools.[75] Today these "school sections" form missing noncontiguous parts of a jigsaw puzzle that is, for the most part, federally or privately owned. State lands are therefore most important in complementing holdings under the federal law so as to make a particular area economically developable. (Ownership of all continuous acreage may be important for such purposes as locating needed work roads, pipelines, or transmission lines.)

Colorado. Leasing of state lands is discretionary on the part of the State Board of Land Commissioners, who must seek optimum long-term revenue. They may lease state lands for the mining of coal at whatever rent and royalty and for whatever length of time they deem appropriate. The Board may sell leased land during the term of the lease as though no lease existed or it may withdraw the land from sale during the full term of the lease.[76]

New Mexico. Prospecting permits for coal can be obtained over a maximum of 640 acres and are valid for a year. On or before the expiration date of the permit, the permittee may be granted a right to develop for a period of up to 5 yr.[77] Such leases may be renewed,[78] but the statute does not specify whether production is required as a precondition. Yearly rental is set by statute, as is the royalty rate of $0.8 per ton.[79]

Utah. Coal on state lands can be leased, but not sold, by the State Land Board.[80] Annual rental may not exceed $1 per acre and is credited against the royalty, which may not exceed 12% of gross value at point of shipment. State leases have a minimum of 10 yr[81] and extend for as long thereafter as the mineral is produced in paying quantities or as long as a minimum royalty set by the Land Board is paid.[81]

Wyoming. Sections 16 and 36 of every township were granted to the state under the Act of Admission. State law provides for renewable coal leases with 10-yr terms,[82] with rental rates to be set by the State Board of Land Commissioners,[83] and royalty set by statute at a rate of at least $0.05 per ton.[83] State leases are not transferable.[83]

Because of the limited nature of state holdings, however, state law will probably have a rather insignificant impact on the choice of a coal source.

2.3.4. Private Ownership. Although private holdings in some of the proposed source states appear to be substantial,[14] little can be said concerning the lease provisions likely to be applicable. No standard lease form is in use, as is the case in the oil and gas industry. It is also unclear to what extent private ownership is actually involved in any of the proposed source areas since, with the exception of southern Utah, where the major deposits are within federal jurisdiction, no field check of land plats has been made (see Sec. 2.5).

2.4. Restrictions on Strip Mining

Legal restrictions on strip mining at the very least will probably affect calculation of costs and may indeed play a determinative role in deciding what source of coal should be used for the proposed plant.

2.4.1. Federal Law. Federal regulations governing the surface mining of coal have been in effect for quite some time.[84] They have recently been revised,[85] but seemingly without the substantial impact that is sure to accompany adoption of the due-diligence and continuous-operation regulations discussed above. After considerable criticism the Department modified its position, changing key language requiring reclamation "to the greatest extent practicable," and substituting an obligation to "minimize, control or prevent" adverse environmental effects,[86] but the strength of the new language also remains unclear.

More important, legislation has been close to adoption during the past 3 yr and would have been enacted in 1975 were it not for President Ford's veto and the short-fall of three votes when the House attempted to override.[87] Efforts to pass a strip mining bill during the 1976 session of Congress have also not succeeded. The House Interior and Insular Affairs Committee did, however, report out HR 9275,[88] a bill that requires surface mine operators to secure and renew permits with terms of 5 yr before proceeding with their activities.[89] Before such a permit could be issued, the operator would be required to submit a mining plan and application that affirmatively show that reclamation will be effected as required by the Act,[90] that cumulative impacts have been considered to prevent irreparable offsite adverse effects,[90] that the proposed mining area is not in an area designated as unsuitable for surface coal mining or under consideration for such designation (unless there has been a substantial legal and financial commitment before the date of enactment,[90] and that if a western (i.e., west of the 100th meridian) alluvial valley floor is to be mined, operations would not interrupt, discontinue, or prevent farming on the valley floor, not adversely affect the quality or quantity of the water systems supplying the floor.[91] Operators would also have to contribute $0.35 per ton produced by surface mining[92] beginning in 1977, and continuing for 15 yr,[93] to be used for reclamation of lands already wasted. In addition, public notice and hearing requirements would be built into the permit-approval process[94] and a performance bond sufficient to assure that all reclamation would be accomplished would be demanded.[95] The House measure would apply to federal, state, and private lands, but states would be given the opportunity to administer surface mining regulations if, within 18 months after the passage of the Act, they submitted programs based on state law which would meet the Act's minimum requirements.[96] Thus, the arrangement would be similar to other federal programs administered by the Environmental Protection Agency (EPA).[97] Although modified to some extent in an effort to obviate the purported grounds for the President's veto,[98] the bill was still a strong one, requiring proof that land is reclaimable before mining commences and necessitating particularly careful consideration of such mining in the western alluvial valleys.

The Senate conceded that its version of this legislation, which resurrected the provisions vetoed by the President in 1975, could not be passed during this session when it adopted the House's versions of the coal leasing provisions discussed above. The Senate's strip mining measure would have applied only to federal lands, would have provided for no reclamation fee, but would have contained more stringent limitations on mining of alluvial valleys, which would bar such operations where farming could be practiced even if substantial investment had already been made.[99] Although there was no passage of this or any similar measure during the 1976 session, it is clear that continuing Congressional support for such stringent legislation exists and that new law restricting strip mining is imminent. Whether the current House version or the more stringent Senate version will ultimately be adopted may well depend on the outcome of the 1976 elections.

It is evident, therefore, that any choice of a coal source which assumes the use of surface mining techniques should only be made after a searching assessment of the problems presented by reclamation, the impact that will result with regard to the water table (if an alluvial valley is involved),[100] and the costs that will be incurred in connection with reclamation requirements and the proposed reclamation fund.

2.4.2. Law Governing Indian Lands. The recently adopted revision of federal surface mining regulations[101] had been planned to encompass Indian lands along with other federal holdings.[102] However, in a recent decision, Interior Secretary Kleppe indicated that separate regulations to govern Indian lands would instead be prepared in the near future.[101] The Navajo Tribe has also recently adopted its own strip mining regulations.[103]

2.4.3. State Law. Most of the western coal states have enacted statutes requiring the reclamation of land affected by the strip mining of coal.[104] The existing practice under federal coal leases is to require compliance with the law of the state where mining is being performed, unless federal regulations are more stringent;[105] consequently, the impact of such laws reaches beyond state lands.

Colorado. In Colorado, strip mining operations are subject to the Colorado Open Mining Land Reclamation Act of 1973.[106] Provisions of the Act are administered by the Land Reclamation Board, part of the Division of Mines within the Department of Natural Resources.[107] No strip mining operations can commence until a permit is issued by the Land Reclamation Board.[108]

Permits are issued upon approval of a written application and authorize open mining within a designated area until June 30 of the fifth year following approval.[109] A permit application must provide complete information on the identity and other mining activities of the proposed operator, the names of the owners of the affected land and of the substance to be mined, and the source of the applicant's legal right to mine.[110] The application must also contain a full description of and timetable for the proposed mining operation.[110] A basic filing fee[111] and a bond[112] must accompany the application. The amount of the bond is not prescribed; instead, the

Act provides that its penalty "shall be in such amount as the board deems necessary to insure the performance of the duties of the operator under this article with respect to the affected land."[113] If the county or municipality within which the affected land is situated has its own requirement of a reclamation plan and bond, and if the plan is deemed adequate by the Board, proof of local compliance is sufficient.[113]

Upon receipt of the application and accompanying materials, the Board is required to issue the permit if the proposal is "reasonable in view of the public interest in physically attractive surroundings and completion of the operation as soon as practicable" and if the operator demonstrates to the Board's satisfaction that the operation will not endanger nearby buildings.[114] However, no permit can be issued in violation of any city, town, or county zoning or subdivision regulation, or contrary to a city, town, or county master plan for the extraction of commercial mineral deposits.[115]

Once a permit is granted, the successful applicant can begin open mining operations, subject to the requirement that a detailed map and reclamation plan for the affected area be filed annually on or before July 1.[116] Specific provisions outline reclamation requirements for forest, range, recreation, and farming purposes,[117] while basic minimum requirements necessary for reclamation for other uses must be agreed upon by the operator and the Board.[118] Reclamation of all land affected by strip mining is required.[119] Reclamation activities must be conducted "with all reasonable diligence"[120] and must be completed within 3 yr of the date of commencement.[121]

Within the term of his permit, an operator may apply for a renewal or for an amendment increasing or decreasing the affected acreage.[122] Filing and Board review of an application for renewal or amendment of a permit is handled under the same procedure as an original application. In connection with an application to increase or decrease affected acreage, bond requirements may also be increased or decreased.[123]

A strip mining operator may seek judicial review of any order issued by the executive director of the Board in a court of proper jurisdiction.[124]

New Mexico. New Mexico land reclamation requirements are outlined in the Coal Surface Mining Act of 1972.[125] As the name implies, the Act requires land reclamation efforts only in the case of strip mining of coal.[126] All land affected by coal strip mining operations must be reclaimed.[127] The Coal Surface Mining Commission is created by the Act, to be composed of seven state officials or designated members of their respective staffs.[128]

No party may engage in strip mining of coal without applying for a permit.[129] An application for a permit consists of a mining plan subject to Commission approval and accompanied by an application and acreage fee.[130] The mining plan must contain a detailed description of the mining operation and a detailed reclamation proposal, including a timetable.[131] Upon approval of the mining plan a permit is issued.[132] Unless it is suspended or revoked, the permit is good for the life of the operation.[133] If the plan is not approved, the Commission must provide the applicant with prompt written notice stating the reasons for disapproval.[134] Amendment of mining plans can be allowed by the Director with the Commission's authorization.[135] If the Commission takes no action on a mining plan within 60 days, the applicant can commence mining operations pending Commission action.[136] No bond is required unless "the Commission finds it necessary to ensure compliance with the Coal Surface Mining Act" and no guidelines for setting the amount are provided in the Act.[137]

Coal mining operations can commence with the granting of a permit.[138] Updated maps showing land mined and reclaimed must be filed annually,[139] and the Commission may establish a regulation requiring periodic progress reports from the operator.[140] Upon a showing of good cause, the Commission can grant time extensions necessary to enable compliance with the Act.[141]

The Commission establishes all reclamation regulations, including timetables and requirements for grading and revegetation.[142] Both in drafting such regulations and in ruling on mining plans the Commission must consider the condition of the land before mining, economic and technical practicability, future productivity of the land for various uses, aesthetic appearance, and the geography of the general area in which a mine is located.[143] No regulation can be adopted by the Commission until a public hearing has been held in Santa Fe upon at least 30 days' notice.[144]

Any action or regulation of the Director of the Commission may be appealed to the State Court of Appeals within 30 days.[145] The Court may set aside a decision or regulation of the Commission only if it conflicts with the law, is arbitrary, capricious or an abuse of discretion, or is not supported by substantial evidence.[146]

Utah. The Utah Mined Land Reclamation Act was passed in 1975 to guarantee that "all mining in the state shall include plans for reclamation of the land affected."[147] Administrative authority to carry out the purpose of the Act resides in the Board and Division of Oil, Gas and Mining, within the Department of Natural Resources, which also has the right to make any regulations necessary to implement the Act.[148] The Board and Division have a duty to coordinate their own regulation activities with those of local and federal bodies to avoid overlapping and conflicting requirements.[149]

No mining operation can commence until a notice of intention is filed with the Division.[150] Beyond the requirements that the notice include a reclamation plan and be accompanied by evidence, such as an insurance policy, that the operator will be responsible for off-site liability or property damage claims, its form is not prescribed in the statutes and may be established by the Board.[150] The statutes do give specific examples of information requirements the Board and Division may choose to impose which, if adopted, would result in a notice very similar in content to a Colorado permit application, with the exception that no bond need accompany a notice of intention.[151]

The Division must complete its evaluation of any notice within 30 days. If there are objections the operator must be given reasonable time to remove them. A tentative decision must then be published once in newspapers in Salt Lake City and the proposed mining area. Mail notice to the local county zoning authority and to affected landowners is also required. Protests may be filed within 30 days of the publication date, and if no protests are filed the notice of intention automatically becomes final at the end of that time. If there are "written objections of substance" a hearing must be held, after which the Board must issue its final decision.[152]

Approval of a notice may not be refused without a hearing[153] and, once granted, is ordinarily valid for the life of the mining operation.[154] However, it may be withdrawn if the operator substantially fails to perform reclamation,[155] fails to provide and maintain surety,[156] or suspends mining operations for more than 2 yr, unless an extension is applied for and granted.[157] Upon withdrawal, mining operations must cease.

After receiving notice of the approval of his notice of intention, but before commencing operations, every operator must provide surety to the Division.[158] Again, the form is not prescribed, although contractual agreements, collateral, bonds, other forms of insured guarantees, securities, or cash are listed as possibilities.[159] The Board must approve a method that satisfies the requirements of the Act and is acceptable to the operator.[160] In determining the amount, which is also left up to the Board, the nature of the mining operation and the scope and cost of the approved reclamation plan are controlling factors,[161] with consideration given also to any similar requirements imposed on the operator by other agencies.[162]

After providing satisfactory surety, the operator may start mining operations. Within 30 days of beginning them he must file a notice of commencement with the Division. Thereafter he must file a progress report at the end of each calendar year.[163] Notice of any suspension of operations for more than 6 months but less than 2 yr,[164] excluding labor disputes, must also be filed with the Division.[165]

No guidelines for a satisfactory reclamation plan are provided in the statutes. "Reclamation" is defined as "actions performed... to shape, stabilize, revegetate, or otherwise treat the land affected in order to achieve a safe, stable, ecological condition and use which will be consistent with local environmental conditions."[166] Listed objectives of the Act are (1) "to return the land...to a stable ecological condition compatible with past, present and probable future land interests" either "concurrently with mining or within a reasonable amount of time thereafter";[167] (2) to minimize mining environmental degradation and meet state and federal standards for health and safety and air and water quality;[168] and (3) to prevent hazards to public safety and welfare.[169] Recognition of full compliance with the Act is demonstrated by full release of the surety.[170] Failure to carry out the reclamation plan outlined in the approved notice of intention may result in an action for forfeiture of the surety after notice to the operator and a hearing by the Board.[171]

All Board and Division rulings are subject to judicial review. The court is to determine issues of fact as well as law, and may issue appropriate injunctions against the activities of the Board or Division.[172]

Wyoming. Any new strip mining of coal in Wyoming is regulated under the terms of the Wyoming Environmental Quality Act.[173] The purpose of the Act is to preserve and enhance the quality of the state's resources by intelligently planning their development, use, and reclamation.[174]

The expense of reclamation and the responsibility for formulating a reclamation plan are borne by the operator.[175] The reclamation plan must be approved by the State Department of Environmental Quality and should be consistent with orderly and economic development of the mining property.[176] Inspection requirements and performance bonds serve to ensure that the land is reclaimed to its "highest prior use."[177]

The Wyoming Environmental Quality Act (EQA) is administered by the Land Quality Division of the State Department of Environmental Quality,[178] which reports to the Environmental Quality Council.[179] The Council has authority to promulgate regulations to carry out the provisions of the Act.[180] The administrator of the Land Quality Division has broad power to enforce the Act. The administrator is primarily responsible for reviewing permit and license applications, setting bond rates, and interpreting and applying the regulations.[181] Appeal from the administrator may be made to the Environmental Quality Council.[182]

The Wyoming EQA does not set specific standards for land reclamation. The Act provides that in promulgating regulations for reclamation, the Environmental Quality Council shall consider, among other factors, adverse environmental impact, highest previous use of affected lands, the earliest possible reclamation timetable, and the stockpiling and reuse of topsoil if possible.[183] Special provisions exist for operations being conducted with permits issued under the Open Cut Reclamation Act of 1969, the precursor to the EQA.[184]

Federal lands over which the United States has exercised its power of federal pre-emption are not subject to state regulation.[185] Other federal lands are subject to a wide spectrum of federal regulations, but since the Wyoming requirements are mutually acceptable, Wyoming regulates reclamation on federal lands.[186] However, the Federal Government can impose stricter requirements.[187]

To conduct mining operations in Wyoming an operator must obtain a mining permit, which requires a reclamation plan.[188] A public hearing must be held before a decision can be rendered on the permit application.[189] If the application is protested, a decision must be made within 30 days.[190] After obtaining a permit, and before commencing mining, an operator must secure a mining license. The primary requirement for the license is the posting of a reclamation and performance bond.[191] The administrator, with the director's approval, sets the bond[192] at a level sufficient to cover reclamation costs of the land to be affected in the first year's operation.[193] The minimum bond requirement is $10 000 but there is no maximum set by the Act.[194]

2.5. Coalfield Descriptions

2.5.1. Southwestern Utah and Arizona Coalfields.

Location. The Alton, Kaiparowits Plateau, and Black Mesa coalfields occur in two isolated groups, the Alton and Kaiparowits Plateau fields in southwestern Utah and the Black Mesa field in northeastern Arizona (Fig. 2-7). The Alton field, about 175 square miles, is roughly horseshoe-shaped, surrounding the Paunsaugunt Plateau and terminating against the Sevier fault on the west and Bryce Canyon on the east.[195] It is contiguous with the Kaiparowits Plateau field to the east across the Paunsaugunt fault. The Kaiparowits field is coincident with the Kaiparowits Plateau, an erosional remnant of Cretaceous strata about 66 miles long and up to 54 miles wide for an area of 1600 square miles.[196] Black Mesa is a very similar erosional remnant of Cretaceous strata about 3200 square miles in an area located in northeastern Arizona.[197] The Utah and Arizona fields are separated by the Colorado River, now in part Lake Powell.

Topography and Climate. The Alton field ranges in elevation from a high of 9400 ft atop the pink cliffs of the Paunsaugunt Plateau to about 5500 ft at the base of the coal outcrops.[195] Topography is mostly bench and slope, with small perennial streams flowing radially away from the cliffs into the Colorado River system. Most of the coal outcrops occur at elevations between 6500 and 7200 ft.

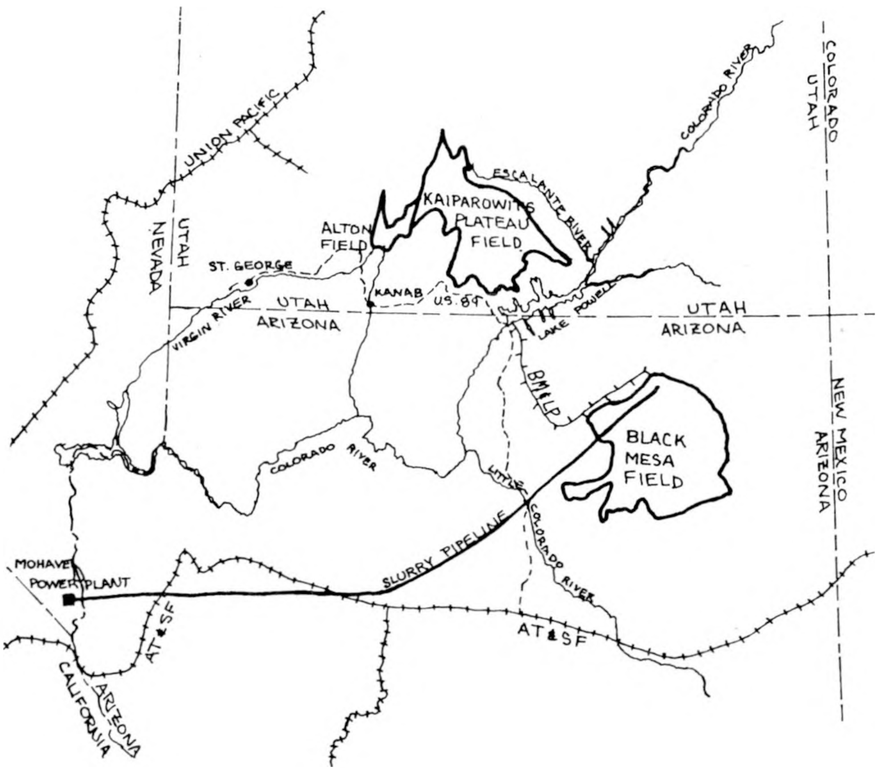


Fig. 2-7.
Southwestern Utah and Arizona coalfields.

The Kaiparowits Plateau is an area of high topography dissected by deeply incised canyons draining into Lake Powell to the southeast. The plateau is bounded by the Straight Cliffs and the Escalante River to the northeast, the East Kaibab Monocline to the west, and erosional cliffs to the south. Elevations range from 3800 in the south to 8000 ft, many cliffs being well over 1000 ft high. Coal seams occur throughout nearly the entire range of elevations.[196]

Black Mesa is a roughly circular plateau rising from 500 to 1000 ft above its surroundings[198] to elevations over 7200 ft. Drainage of the plateau surface is to the southwest by incised ephemeral streams that discharge into the Little Colorado River. Both Kaiparowits Plateau and Black Mesa occupy the respective centers of large structural basins, toward which all surrounding strata dip.

The regional climate is arid, as low as 5 in. of annual precipitation, although the higher elevations receive about 20 in. of rainfall annually. Precipitation is bimodally distributed into winter and summer peaks, the summer thundershower season usually bringing the most rain and also the most destructive storms.[195] Spring is usually the driest season. Temperatures are hot in the summer and cold in the winter.

History. The Alton and Kaiparowits Plateau coalfields have at present (1975) no active coal mines and have produced less than 50 000 and 25 000 short tons, respectively.[199] Although limited mining was begun in both fields almost as soon as settlers arrived in the 1870s, the area's isolation and sparse population kept interest in the coal deposits to a minimum. A small boom in coal lands started in 1960 and ran through 1970, during which time most of the attractive coal lands were leased and proposals for large power plants were made. Now nearly all development proposals have stagnated because of resistance from conservation groups and increasingly prohibitive economics.

The Black Mesa coalfield followed a similar but slightly accelerated path. Up to the time the current developments began in 1970, about 400 000 tons were removed from the field by underground mining, approximately 100 000 tons by prehistoric Indians.[200] Peabody Coal Company has leased large portions of the field from the Navajo Nation since 1964, and currently has two surface mines that produced 6 985 755 short tons in 1975.[201] The Black Mesa mine ships coal by slurry pipeline to the Mohave power plant in Nevada, and the Kayenta mine serves the Navajo power plant near Page, Arizona, via the closed-circuit Black Mesa and Lake Powell Railway.

Transportation and Population. Except for the coal slurry pipeline and the closed-circuit railroad mentioned above, these coalfields are very remote from any transportation system capable of carrying large quantities of coal to a southern California market. All three are more than 100 construction-miles from the nearest throughgoing railroad over very difficult terrain (see Sec. 3.1.3). No major paved roads provide access within the coalfields, although secondary roads skirt the fields: US Highway 89 and Utah 12-54 in Utah, and US Highway 160 and Arizona 264 in Arizona.

All fields are also remote from any population centers. The largest towns near the Utah coalfields are Kanab (1341) and Panguitch (1318), and the populations of Kane and Garfield Counties probably total together little more than 5000. Black Mesa is even more remote from the nearest large population centers of Page and Flagstaff, Arizona. Bryce Canyon, Zion, Grand Canyon, Arches, Capitol Reef, and Canyonlands National Parks, and Glen Canyon National Recreation Area, however, all attract many hundreds of thousands of people into this region annually.

Geology and Deposits. Coal in the Alton field is contained in two zones near the base and near the top of the Dakota Sandstone, the lowermost Cretaceous unit in the region.[202] The lower Bald Knoll zone contains up to four closely spaced coal seams that together average 5.5 ft, although they are lenticular and often badly split.[203] The upper Smirl coal zone is higher in quality and thicker, averaging about 12 ft with only thin rock splits.[204]

Coal deposits in the Kaiparowits Plateau and the Black Mesa coalfields are similar in that they are both found in Upper Cretaceous erosional remnants centered in large structural basins. The commercially important coal in the Kaiparowits field is found in from one to four or more zones in the John Henry Member of the Upper Cretaceous Straight Cliffs Formation[205] and possibly in the underlying Dakota Sandstone.[206] These seams, in ascending order, are the Dakota (possibly commercial in the Tropic area), lower Christensen, Rees, Alvey, and Upper Alvey.[205] The Christensen coal zone is the most consistent and contains the largest deposits, but in some areas the Alvey coal zone is dominant. Individual coal beds are occasionally up to 25 ft thick and are often separated by only thin rock partings, leading in one instance to 80 ft of coal in only 115 ft of strata.[207] These individual coal beds are very lenticular, although the coal zones are reasonably consistent. For the most part, the beds dip very gently and there are very few faults on the plateau,[208] although extensive natural burning of the coal has created a great deal of surface and subsurface disturbance through collapse.[205]

The Black Mesa coalfield contains coal in three formations: the basal Cretaceous Dakota Sandstone and the Toreva and Wepo Formations of the Mesaverde Group.[200] Little is known about the seams other than from outcrop exposures, although Peabody is mining six seams in the Wepo Formation that range in thickness from 5 to 28 ft.[200] All are lenticular and of inconsistent quality. Dips are minor as is faulting.

Quality. Table 2-11 lists the coal quality data for the three coalfields. The coal in Alton ranges in rank from subbituminous C to high-volatile C bituminous with low ash and medium sulfur content.[204] Kaiparowits coal ranges from subbituminous C to high-volatile A bituminous with low ash and low-to-medium sulfur content.[209] The Christensen zone is consistently the highest in quality. Coal from Peabody's Black Mesa mine averaged about 11 000 Btu/lb., 10.9% ash and 0.40% sulfur in 1975, making it subbituminous A in rank.[210] Since many of the samples averaged in Table 2-11 were from weathered, oxidized outcrop samples, the true quality of these coals should be somewhat higher. None of the coal is of coking quality.

Resources. Detailed mapping of the geology and coal resources of the Alton and Kaiparowits Plateau coalfields is continuing, as are the exploratory drilling programs of many of the large federal leaseholders. Thus, although no large mining operation has yet commenced on either field, good information concerning the coal deposits is still being generated.[211] Correlation of coal beds is still difficult, however, and many areas still remain to be explored. The opposite situation exists at Black Mesa, where

TABLE 2-11

COAL QUALITY DATA FOR SOUTHWESTERN UTAH AND ARIZONA COALFIELDS

Field/Zone	Moisture (%)	Ash (%)	Sulfur (%)	Heat Content (Btu/lb)[e]
Alton[a]				
Smirl Zone	18.8	9.6	1.3	10 772
Bald Knoll Zone	13.8	15.8	0.74	9 227
Kaiparowits Plateau[b]	11.3	8.96	0.87	11 999
Black Mesa[c]				
Wepo	7.6	5.1	0.4-0.9[d]	11 950
Toreva	6.3	21.3	0.6-1.3[d]	9 630
Dakota	10.1	15.2	0.7-2.3[d]	8 160

[a]Reference 203.

[b]Reference 209.

[c]Paul Averitt and R.B. O'Sullivan, 1969. "Coal." In "Mineral and Water Resources of Arizona." Arizona Bureau of Mines Bulletin No. 180, 59-69, p. 64.

[d]Reference 200.

[e]As received.

very large-scale mining operations have been taking place since 1970, yet there is no known exploration program on the mesa. Most of the mesa can only be explored by drilling. Thus very little is known about the coal deposits outside the Peabody leases and estimations of total coal resources have varied greatly. Table 2-12 shows the current resource estimates for these three fields and these estimates are subject to revision. Based even upon these rough estimates, there is an enormous quantity of coal in these fields.

Mineability and Production Costs. The Alton coalfield contains extensive resources that could be mined underground, but, as with the Black Mesa coalfield, any near-term exploitation will most probably concentrate on the coal obtainable through surface mining. Drilling has disclosed uniform and clean coal in beds 12 to 20 ft thick with less than 60 ft of easily removed overburden over a large portion of the field.[212] The cost of production is predicted to be comparable with coal from the Navajo mine in the Four Corners area of New Mexico, or about $5 per ton as shown in Table 2-13. Coal from Black Mesa is also easily mined, although the coal is more lenticular and contains frequent partings. Average 1975 price for Black Mesa coal was $3.09 per ton.[210]

Coal from the Kaiparowits Plateau coalfield must be mined underground, except for a few minor occurrences in the northwest. Factors affecting the cost of underground mining in the Kaiparowits field include the extreme lenticularity and discontinuous nature of individual seams, thick seams, undulating roofs, and multiple seams.[213] Faults and folds should not be of consequence. Much of the southern area is under 800 ft of cover or less, and access will be through any of the numerous canyons cutting into the plateau surface.[206] Many factors are still unknown, such as possible difficulties with water from the many massive sandstones in the sequence, because of the lack of any large-scale production from the field. The cost of coal produced from the Kaiparowits Plateau field, however, is expected to be only slightly higher than that from similarly equipped mines.[214]

Resource Ownership. Land in the Alton field is owned by the Federal Government, private interests, and the State of Utah.[204] Coal lands are

TABLE 2-12

ESTIMATED COAL RESOURCES[a] OF SOUTHERN UTAH AND ARIZONA COALFIELDS

Field	Total Resource Estimates		Estimated Recoverable Resources	Strippable	
	Upper	Lower		Resources	Reserves
Alton[b]	---	2 149[e]	1 000[e]	203[d,f]	---
Kaiparowits[c] Plateau	40 000	15 198[e]	4 000[e]	---	---
Black Mesa[d]	21 000	14 000	---	1 000[g]	387[g]

[a]Listings in millions of short tons.

[b]Reference 195, p. 18-19.

[c]Reference 196, p. 102.

[d]Reference 200.

[e]Seams ~4 ft thick.

[f]Within 200 ft of the surface.

[g]Within 130 ft of the surface.

primarily controlled by the BLM, which administers most of the federal and private land on which coal rights are reserved. The two primary leaseholders are Utah International, Inc., and Nevada Electric Investment Company.[215] Nearly all the strippable coal has already been leased.

Land and mineral resources of the Kaiparowits Plateau are controlled by the US Government and State of Utah in about a 10 to 1 ratio.[216] Major leaseholders (1000 acres or more) are listed in Table 2-14. Since the leasing boom in the early 1960s, little additional acreage has been leased, although extensive ownership changes have occurred.

The coal lands of Black Mesa are under the exclusive control of the Navajo and Hopi Indian Nations. Peabody has signed lease agreements with the tribes covering 64 858 acres, of which about 14 000 acres are underlain by recoverable coal.[200]

Future Development. The two major leaseholders of coal lands in the Alton field are planning to produce coal together for a small power plant near St. George, Utah (Warner Valley), and for a larger plant near Las Vegas, Nevada. The project is apparently delayed, however, and the coal leases are due for renewal in the 1981-1988 time period.[217] The coal was to be moved by slurry. Southern California Edison, San Diego Gas & Electric, and Arizona Public Service, having dropped their plans to build the controversial 3000-MWe Kaiparowits power plant, are now considering the construction of a coal gasification plant that would use about 30 000 acre-ft of water from Lake Powell.[218] Utah Power and Light's proposed Garfield power plant and El Paso Natural Gas' proposed gasification plant both appear to be stalled and unlikely to be pursued in the near future. In Black Mesa, the Navajo Indian Tribe is not pushing for development of their coal resources, and additional production is not expected.

Transportation is the major hurdle that must be overcome before development of these fields can take place. If an economical method of transporting the coal out of these remote regions can be found, as well as a site for its conversion into a usable energy form, then these fields' close proximity to the metropolitan Los Angeles load center will make them very valuable. Present federal coal lands leaseholders will become increasingly interested in finding markets as the leases require renewal between 1981-1988.

TABLE 2-13

PRICE OF COAL FROM SOUTHWESTERN UTAH AND ARIZONA COALFIELDS, 1975

Field	Production Method	Price: Dollars per Ton	Price: Cents per Million Btu
Alton[a]	surface	5.00	23.21
Kaiparowits[b] Plateau	underground	11.00	45.84
Black Mesa[c]	surface	3.09	14.26

[a]Based on price of coal from Navajo Field, New Mexico, which is mined under similar conditions. No actual 1975 production. Ref. 212.

[b]Based on the estimated price of coal from the Book Cliffs and Wasatch Plateau Fields with a $1 per ton increase due to more difficult geologic conditions. No actual 1975 production. Ref. 214.

[c]Average price of steam coal delivered from Black Mesa in 1975, less 29% for transportation costs. Reference 21, and Richard J. Barret, William A. Beyer, and Charles D. Kolstad, "Rocky Mountain Energy 1974: Flows, Employment, Prices," Los Alamos Scientific Laboratory report LA-6122-MS (October 1975).

TABLE 2-14

MAJOR KAIPAROWITS PLATEAU COAL LANDS LEASEHOLDERS[a]

	Federal Leases	Federal Permits	State Leases
Consolidation Coal Co.	X		
El Paso Natural Gas Co.	X		X
Hiko Bell Mining and Oil	X	X	X
Jesse Knight		X	
Peabody Coal Co.	X		X
Resources Co.	X		X
Sun Oil		X	X
Utah Power and Light[b]		X	X
Woods Petroleum		X	

[a]Holders of 1000 or more acres in 1973 (Ref. 213, p. 53-58 and Ref. 215)

[b]Utah Power and Light bought option in 1971, was assigned right in 1973 with amendment in 1974. No effective federal right until action after leasing moratorium.

2.5.2. Central Utah Coalfields.

Location. The Book Cliffs, Wasatch Plateau, and Emery coalfields together form a nearly continuous belt of mineable coal from 4 to 20 miles wide and 180 miles long underlying more than 1500 square miles (Fig. 2-8). The fields run in an arc from the canyon of the Green River on the east to the North Gordon fault zone on the west (Book Cliffs field), then west of the fault, north to the Denver and Rio Grande Western (D&RGW) Railroad mainline and south to the Fish Lake Plateau (Wasatch Plateau field), then east to the Coal Cliffs escarpment (Emery field).

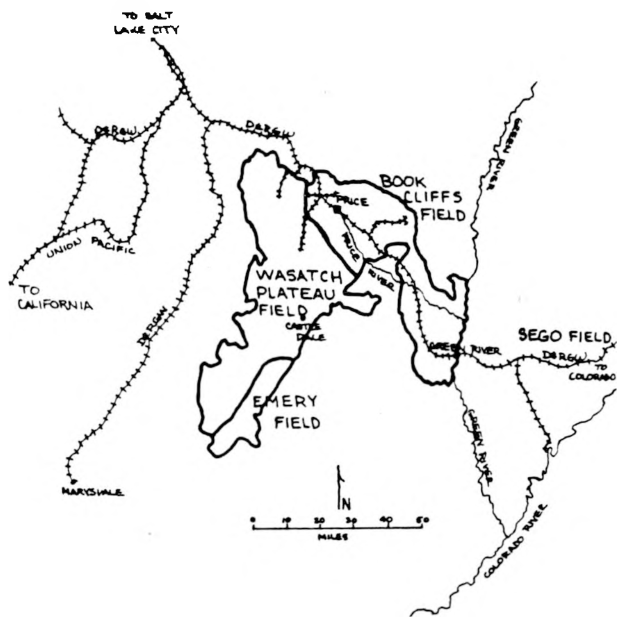


Fig. 2-8.
Central Utah coalfields.

The fields are usually delineated by escarpments where the coal seams crop out and by the 3000-ft cover line, below which coal will not be economically recoverable for some time. The fields are as close as 70 air miles south-southeast of Salt Lake City and are located in Carbon, Emery, Sanpete, Sevier, and Utah Counties.

Topography and Climate. One characteristic common to all fields is their rugged topography. The Book Cliffs, for which the easternmost field is named, rise nearly vertically from 1000 to 2000 ft above their base, reaching elevations from 6000 to almost 9000 ft. The Wasatch Plateau consists of deep canyons cutting through the eastern 1000-ft cliff, creating a rugged topography from 7000 to 10 000 ft in elevation. The Emery field consists of the 800-ft-high Coal Cliffs on the east, which slope back to the west into the Castle Valley, and finally, in the far west, the hills at the foot of the Wasatch Plateau. Coal crops out along the Cliffs and along the walls of the canyons at elevations from 6000 to 8500 ft in the Book Cliffs and 7000 to 8000 ft in the Wasatch Plateau.

The two major drainage systems in the area are the Green River, which flows through from Wyoming and forms the eastern boundary of the field, and the Price River, which, after rising in the Wasatch

Plateau, crosses the Book Cliffs at both the west and southeast ends, emptying finally into the Green River. Many other streams, such as Huntington, Cottonwood, Ferron, Muddy, and Ivie Creeks, originate in the Wasatch Plateau and eventually reach the Colorado River to the southeast. Precipitation and temperature vary greatly throughout the region. Annual rainfall varies from 5 to 20 in. on the Book Cliffs, and up to 40 in. on the Wasatch Plateau. The precipitation increases with elevation and occurs mostly from winter cyclonic storms. Occasional summer thundershowers can create flash floods, and the total precipitation is highly variable from one year to the next. Temperatures range from cool to hot at the lower elevations and from very cold to mild atop the highlands. Temperatures can also fluctuate greatly from the normal.

History. The Book Cliffs and Wasatch Plateau coalfields have together produced over 300 million tons since the first mines opened in 1889 and 1874, respectively (nearly 97% of all the coal mined in Utah).[219] Although the Book Cliffs field has historically outproduced the Wasatch Plateau field about 2 to 1, 1975 production in the Wasatch Plateau was 4 032 567 short tons to 2 241 376 short tons in the Book Cliffs (Table 2-15). The Emery Field has remained small, producing only 2 million short tons since 1881.

Transportation and Population. The Book Cliffs and northernmost Wasatch Plateau fields are served by the mainline D&RGW, which runs from Denver, Colorado, to Salt Lake City, Utah, first below the Book Cliffs then up Price Canyon toward the plateau. Most coal areas are served by one of six spurlines: one running to Sunnyside, one east and one west from Helper, one south from Helper to Hiawatha, one south from Colton to Scofield and Clearcreek, and the extension south from Thistle through the Sanpete and Sevier Valleys to Marysvale. Newly completed Interstate 70 connects Salina and Green River through the southern ends of the Emery and Wasatch Plateau fields, and US Highway 50-6 parallels the railroad mainline. Utah Highway 10 joins the northern and southern east-west routes through the Castle Valley at the foot of the Wasatch Plateau.

By far the largest population center in the region is the Price (6218)-Helper (1964) area which had an approximate 1970 area population of about 11 000.[220] Regional population in 1970 was slightly over 18 000, down from the 1960 figures. Almost all settlements are in the valleys below the escarpments.

TABLE 2-15

COAL PRODUCTION FROM CENTRAL UTAH COALFIELDS, 1975

Field	Active Mines	Production (Short Tons)
Wasatch Plateau	9	4 032 567
Book Cliffs	5	2 241 376
Emery	3	134 366
Totals	17	6 937 537

(Source: Ref. 240.)

Geology and Deposits. All commercial coal deposits in the Book Cliffs and Wasatch Plateau fields occur in the Upper Cretaceous Blackhawk Formation of the Mesaverde Group. In the Book Cliffs field, the unit is thickest and oldest in the west, and little mineable coal has been found in the southeast.[221] Important seams of the field are listed in Table 2-16; the older seams are more important in the west (Castlegate and Soldier Canyon Areas) and the younger seams in the southeast (Sunnyside and Woodside areas).[222] The lower Sunnyside bed is the most important of the field because of its great areal extent and its ability to produce a metallurgical coke. The beds generally exhibit low dips away from the cliff face and the field is not badly faulted. In the Wasatch Plateau field, the commercial coal beds lie in the lower 250 to 350 ft of the Blackhawk Formation.[223] The two most important coal beds in the field are the Hiawatha (up to 28 ft thick) because of its great areal extent, and the Castelgate "A" bed (up to 19 ft thick).[224] Most of the other 20 named coal beds are lenticular and of limited extent but are well developed in one specific area. Faulting is prevalent and sometimes complicated, but most often occurs in north-south-trending zones.[225]

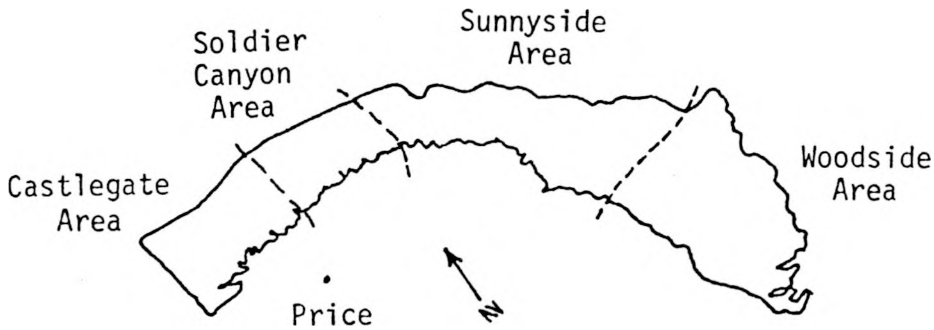
The important coal seams of the Emery field occur in the Upper Cretaceous Ferron Sandstone Member

TABLE 2-16

IMPORTANT BOOK CLIFFS COAL SEAMS

Younger

Coalbed or Zone	Area of Importance
Beckwith Zone	Woodside
Upper Sunnyside Bed	Sunnyside
Lower Sunnyside Bed	Sunnyside
Rock Creek Bed	Soldier Canyon and Sunnyside
Fish Creek Bed	Soldier Canyon
Gilson Bed	Soldier Canyon
Kenilworth	Castlegate
Castlegate Zone	Castlegate
Spring Canyon Zone	Castlegate



(Source: Ref. 221.)

of the Mancos Shale, stratigraphically 2390 to 4500 ft below the overlying coalbearing Blackhawk Formation.[226] Some coal also occurs in the underlying Cretaceous Dakota Sandstone and the overlying Emery Sandstone. The coal in the Ferron Sandstone is very lenticular, dips are gentle, and faulting is generally inconsequential.[227] The coal occurs in recognized coal beds or zones with local thicknesses up to 20 ft.[228]

Quality. The coal quality is remarkably consistent throughout the Book Cliffs and Wasatch Plateau fields, and both fields are very similar in quality (Table 2-17). Quality deteriorates slightly toward the outer ends of both fields, and generally, the Book Cliffs field averages slightly lower in moisture and volatile matter and higher in fixed carbon than the Wasatch Plateau field.[229] The Emery field is poorer in quality and shows a much greater variation in quality characteristics, due partly to the sampling of weathered outcrops and abandoned prospects and to the large number of splits and impurities in much of the coal.[230]

Coal of coking quality is found only in the Upper and Lower Sunnyside beds of the Book Cliffs field. These coals, however, must be washed to remove pyritic sulfur (less than 30%) and blended with up to 20% of other low- and medium-volatile coals to obtain an industrially acceptable metallurgical coke.[231]

Resources. Information about the coal deposits in the north parts of the Book Cliffs and Wasatch Plateau fields is quite good, especially in the heavily developed areas. In the south part of the Book Cliffs field reconnaissance mapping has been completed only in the cliffs and more detailed mapping will be necessary, especially on the plateau surface.[232] Subsurface drill-hole data are lacking for the southern

TABLE 2-17

CENTRAL UTAH COALFIELDS COAL QUALITY

Field/Area	Rank	Moisture (%)	Ash (%)	Sulfur (%)	Btu[a] (Pound)
Book Cliffs	Hi-Vol. B Bit.	4.8	6.7	0.85	12 762
Castlegate	Hi-Vol. B Bit.	4.3	6.6	0.53	12 825
Soldier Canyon	Hi-Vol. B Bit.	4.8	7.0	0.49	12 531
Sunnyside	Hi-Vol. B Bit.	5.0	6.4	1.09	12 648
Woodside	Hi-Vol. B Bit.	5.5	6.7	0.70	12 664
Wasatch Plateau	Hi-Vol. B Bit.	6.1	6.5	0.60	12 589
North Section	Hi-Vol. C Bit.	7.2	6.1	0.64	12 200
Hiawatha	Hi-Vol. B Bit.	5.4	6.6	0.59	12 744
South Section	Hi-Vol. C Bit.	8.8	6.7	0.56	11 727
Emery	Hi-Vol. C Bit.	7.4	8.9	0.99	11 424

[a]As received.

(Source: Ref. 219, pp. 555, 557, 558.)

region and for many areas with more than 2000 ft of overburden. Subsurface data are also lacking for much of the Wasatch Plateau field, and little is known of the coal deposits west of the surface exposures and present mines.[233] The Emery field has not had a comprehensive study and much exploration remains to be undertaken.[230] In general, established mining areas are fairly well known and receive continued study at the expense of investigating the undeveloped areas.

Total resources for the central Utah coalfields in beds over 4 ft thick and with less than 3000 ft of overburden are 15 601 million short tons (Table 2-18). It is estimated that 3317 million tons of this total is recoverable.

Mineability and Production Costs. Except for a few small areas that could be stripped in the Wasatch Plateau and Emery fields, all coal must be mined underground in the central Utah coalfields. In the Book Cliffs and Wasatch Plateau fields most of the easily recoverable coal has already been mined, and the best resources are now under more than 1000 ft of cover. Mining at greater depths will increase the problems of coal dust and gas control, ventilation, and rock bursts, as well as necessitating thicker pillars, which will lower resource recoverability. Haulage costs will also increase as mines go deeper.

Adverse geologic conditions that will increase the costs of mining include beds that are generally lenticular and of variable thickness, wants, undulating floors and roofs, and splits. Faulting, water, variable dips, and multiple seams are greater problems in the Wasatch Plateau field than in the other two fields.[234] Multiple seams, undulating floors and roofs, and splits will be the greatest problems in the Emery field.[235]

Prices for underground central Utah steam coal were estimated to be about $5 to $7 per ton in 1968[236] and nearly $11.50 in 1974.[237] It is estimated here that a large underground mine under long-term contract could have sold steam coal in 1975 for $10 per ton (39.18¢/mmBtu) from the Book Cliffs, $10 per ton (39.72¢/mmBtu) from the Wasatch Plateau, and $12 per ton (48.14¢/mmBtu) from the Emery field.[238]

Resource Ownership. Most coal lands in the central Utah fields are owned privately or by the Federal Government. Private ownership is concentrated in the developed areas of the Book Cliffs and Wasatch Plateau fields and in the Castle Valley

TABLE 2-18

CENTRAL UTAH COALFIELD RESOURCES

Coal in beds thicker than 4 ft and with less than 3 000 ft of overburden, in millions of short tons. (Source: Ref. 209, p. 550 and 554.)

Field	Principal[a] Remaining Resource	Potential[b] Resources	Estimated Recoverability (%)	Recoverable Resource
Book Cliffs	3 070.9	515.6	35	1 074.8
Wasatch Plateau	6 047.3	3 888.0	30	1 814.2
Emery	1 424.9	634.5	30	427.5
Totals	10 563.1	5 038.1	31	3 316.5

[a]Principal remaining resource is the sum of the measured, indicated, and inferred resources minus production from these resources (through 1970).

Measured resources are based on adequate exploration and development data; properly correlated; control no more than one-half mile apart.

Indicated resources are based on geologic measurement supplemented by limited drill-hole information and limited to 1-1/2 miles from a control point.

Inferred resources are based on geologic inference and projection of the habit of the coal beyond 1-1/2 miles from control points.

[b]Potential resources are based on geographic and geologic positions with little supporting data; includes coal up to 3000 ft of cover.

in the Emery Field. The BLM administers more than 50% of the coal lands in both the Book Cliffs and Emery fields, and the National Forest Service controls more than 50% of the Wasatch Plateau field.[239] Over half of the Emery and Book Cliffs fields are already leased, and the remaining lands are not expected to contain economically mineable deposits. Much of the southern Wasatch Plateau field remains to be leased. Current (1973) major federal leaseholders are listed in Table 2-19, along with other holders of major coal land acreage.

Future Development. Production from the central Utah coalfields is expected to increase dramatically in 1977 and to continue expansion into the 1980s. Braztah Corporation is developing three new mines in the old Castlegate area of the Book Cliffs field for the American Electric Power System, aiming for annual production of 3 million short tons by 1977, and 6.5 million short tons between 1980 and 2020.[240] Utah Power and Light's nearly completed Emery power plant and the Huntington power plant addition will require 3 million short tons of coal from the Wasatch Plateau field by 1980. The construction of the proposed Castle Valley Railroad will open the southern Wasatch Plateau and Emery fields to economical transportation and greatly increase their marketability. Most coal companies are seeking expanded markets, although coal prices might rise to $15 to $20 per ton in the contract period.[240] It appears that very good quality coal is available but that mining conditions will make the cost slightly higher than existing coal sources in Utah.

2.5.3. New Mexico Coalfields.

Location. The Star Lake and Gallup coalfields are located in the San Juan Basin coal region in the northwestern corner of New Mexico (Fig. 2-9). These are only 2 of the 19 fields or areas into which the San

TABLE 2-19

HOLDERS OF MAJOR COAL LAND ACREAGES IN THE CENTRAL UTAH COALFIELDS

A. Federal Lands (1973 - 1000 or more acres)

Company	County
Braztah Corporation	Carbon
California Portland Cement	Carbon
Centennial Coal Association	Carbon
F. V. Colombo (Deceased- Walker Bank, Administrators)	Carbon
Consolidation Coal and Kemmerer Coal	Sevier, Carbon
Heiner Coal Company (Coastal State Energy)	Carbon, Sevier, Emery
Kaiser Steel	Carbon, Emery
Kennecott Coal Company	Carbon
Jesse H. Knight	Sevier
Armeda N. McKinnon	Carbon
Malcolm M. McKinnon	Emery, Carbon
Peabody Coal Company	Emery
Plateau Mining Company	Carbon, Emery
Spring Canyon Coal Company	Carbon
Southern Utah Fuel (Coastal State Energy)	Sevier
United States Fuel Company	Emery
United States Steel Corporation	Carbon, Emery
Utah Power and Light	Emery

B. Other (1969 - 1000 or more acres)

Book Cliff Field	Wasatch Plateau Field
Carbon School District	Co-operative Security
Carbon Development	Energy Reserves
Premium Coal	Huntington Corporation
Royal Coal	Paramount
L. D. Sutton	Rilda Corporation
	Valley Camp Coal Company

Emery Field
Mountain States Resources Corporation
D. Hunter

(Source: Ref. 215, p. 107-111, Ref. 220, p. 91, Ref. 221, p. 274, Ref. 226, p. 436.)

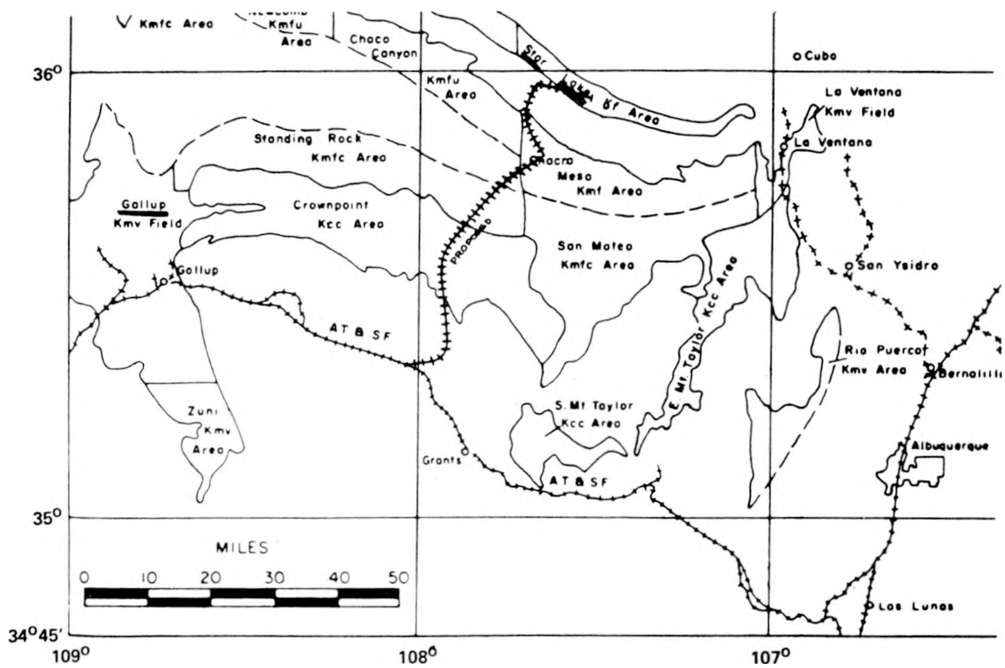


Fig. 2-9.
New Mexico coalfields. (Source: Ref. 242, p. 5.)

Juan Basin has been divided.[241] Most of these areas are based on geologic and physiographic divisions, although some boundaries are drawn along surveyed lines for convenience.[242] These two fields were selected because of their access to transportation. The Gallup field is centered on the town of Gallup and extends north-south for about 50 miles. Its eastern and western boundaries are primarily structural with the northern and southern boundaries arbitrarily chosen.

The Star Lake area, as described in this report, includes portions of the Bisti, Chaco Canyon, Chacra Mesa, Standing Rock, and Crownpoint areas that may lie along the proposed spur of the Santa Fe Railroad into the Star Lake area (see Sec. 3.1.2). This extension, as shown in Fig. 2-9, would open a large portion of the San Juan Basin region to economic exploitation.

Topography and Climate. The Gallup field lies at about 6500 ft (the elevation of Gallup) and is characterized by mesas and rolling tablelands. The area is drained by the ephemeral Rio Puerco of the West, which eventually flows into the Little Colorado River. Vegetation is sparse as the area receives little rainfall (up to 12 in.). Summer thunderstorms deliver most of the moisture that falls in this very arid region. The Star Lake area, deep within the San Juan Basin, is even more arid, receiving usually less than 10 in. annually. The grasslands have been overgrazed, leaving much of the area devoid of vegetation.[243] The area is characterized by low, south-facing cuestas broken by broad, sandy arroyos.

History. The Gallup area historically has been the site of the largest coal mining efforts in the basin.[244] Mining began in the 1880s to serve the railway, with peak production from the underground mines coming in 1920 at 825 000 short tons.[245] Large-scale strip mining began in 1961 with the opening of Pittsburgh and Midway Coal Mining Company's McKinley mine. Production in 1975 was about 470 000 short tons.[201] The Star Lake area has yet to produce commercially.

Transportation and Population. About 150 000 people live in and around the San Juan Basin, mostly in communities of under 500.[246] Gallup has a population of under 20 000, and the only population centers near the Star Lake area are Hospah and Star Lake itself, the area being especially devoid of population.

The mainline of the Santa Fe Railway passes through Gallup and skirts the southern boundary of the region eastward toward Albuquerque. A spur serves the McKinley mine. The proposed Star Lake spur would leave the mainline at Prewitt, travel northward across and along the Continental Divide to Pueblo Pintado, then turn southeastward to Star Lake. Interstate 40 parallels the railroad mainline, with US 666 and New Mexico 68 and 32 serving the Gallup area. The Star Lake area is accessible only by dirt and gravel roads.

Geology and Deposits. The San Juan Basin is a broad, roughly circular structural basin with its deepest part near the northeastern corner.[247] Dips are thus generally steep on the eastern and northern boundaries and gentle on the south and west away from the monoclines. The coal deposits are found throughout a wide range of Cretaceous strata that were deposited near the constantly changing shoreline of a vast inland sea.[248] Subsequent deformation and erosion have exposed these coals, oldest at the outer edges and progressively younger toward the center.

The Gallup coalfield is in a southwestern extension of the San Juan Basin known as the Gallup Sag.[245] Commercial coal beds occur in the Upper Cretaceous Mesaverde Group in the Gallup Sandstone (oldest), the Dilco and Gibson Members of the Crevasse Canyon Formation, and the Cleary Member of the Menefee Formation, the last three being best developed. The best stripping deposits are found in the combined Gibson and Cleary Members in the vicinity of the McKinley Mine, where there are five beds with thicknesses from 2 to 15 ft.[249] The beds are very irregular, with erratic changes in thickness and great lenticularity; no seam is continuous for more than 2 miles.[245]

Coals in the Star Lake area are found in the Upper Cretaceous Fruitland Formation which overlies the Mesaverde Group.[243] The coal beds are thought to be very lenticular and highly variable in thickness.[250] One drill-hole test passed through two coal beds with thicknesses of 16 and 13 ft, both containing numerous thin shale partings.

The only other strippable coal deposits within 10 miles of the proposed railroad spur are in the Standing Rock area in the Cleary Member of the Menefee Formation.[251] These coals are also very lenticular with variable thicknesses.[252] Coal up to 28 ft thick has been drilled, although it contained numerous, often thick, shale partings.

Quality. The coal quality data given in Table 2-20 are probably representative only for the Gallup field. So few analyses have been made public on the coals of the other two areas that these averages can only be considered as indications. The high ash content in the Star Lake coals is presumably the result of the numerous thin shale partings and could also presumably be lowered by washing.

Resources. At present the extent of public information available for establishing the quantity of strippable coal deposits in the Gallup field makes the resource estimates tentative, and the figures for the Star Lake and Standing Rock areas are speculative at best. Table 2-21 gives the estimated original strippable resources for these fields. In the Star lake area the estimate is based on oil and test logs, one drill hole, and general data released by a lessee based on drilling.[253] The Standing Rock information is based upon extensive field reconnaissance, one test hole, and a number of oil test logs.[251] The total figure for the Star Lake area may be low by an order of magnitude.

Mineability and Production Costs. Of the two areas, only the Gallup field has produced and is still producing coal. Coal is mined using a combination of contour and area stripping and requires blasting the overburden before removal.[254] Although the operation is relatively small, which results in relatively high coal prices,[255] larger operations should lower the price to about \$6 per ton (28.20¢/mmBtu). Production in the Star Lake area should be less expensive, with prices similar to the Navajo Fruitland field to the northwest.[243] Prices in 1975 for 7 184 900 short tons of coal from that field averaged \$4.037 per ton or 22.62¢/mmBtu.[255] Star Lake area

TABLE 2-20

REPRESENTATIVE COAL QUALITY DATA FROM NEW MEXICO COAL FIELDS

Field	Rank	Moisture (%)	Ash (%)	Sulfur (%)	Btu/lb.
Gallup[a]	Hi-Vol. C	15.2	7.95	0.42	10 637
Star Lake[b]	Hi-Vol. C	10.7	15.	0.4	9 400
		11.5	20.	0.7	10 200
Standing Rock[c]		14.9	5.2	0.5	11 050

[a]Typical analysis of coal from the McKinley Mine. Reference 242, p. 41.

[b]Average ranges from drill-hole cores. Reference 241, p. 526.

[c]Average of coal mined outside the area but from the same zone. Reference 241, p. 527.

TABLE 2-21

ESTIMATED ORIGINAL STRIPPABLE RESOURCES IN THE NEW MEXICO COALFIELDS

	Millions of short tons			
Field or Area	Overburden <150 Feet		Overburden 150 to 250 ft	
Gallup[a]	250		180	
Star Lake	365		345	
Star Lake[b]		365		270
Standing Rock[c]		---		75
Total	615		525	
Grand Total			1140	

[a]Reference 249.

[b]Reference 253.

[c]Reference 251.

prices are estimated here at about $4.50 per ton or 23.68¢/mmBtu.

Resource Ownership. In the Gallup field, the only federal lessee is the Gulf Oil Corporation, whose sales agent is the Pittsburgh and Midway Coal Mining Company.[256] In the Star Lake area, only the Seneca Oil Company has federal coal leases near the proposed railroad spur. Additionally, Table 2-22 lists the holders of federal preference-right lease applications in the Bisti and Star Lake areas. It is not known how close these properties are to the proposed railroad spur, nor if they will eventually be approved as preference-right leases.

Santa Fe Industries owns three parcels of land, two in the Star Lake area and one in the Standing

TABLE 2-22

NEW MEXICO PREFERENCE-RIGHT LEASE APPLICATIONS[a]

Applicant	Acres
Eastern Association Property Corporation	35 938
Ark Land Company	21 849
Thermal Energy Company	12 032
Kin-Ark Corporation	2 880
United Electric Company	2 811
H. N. Cunningham	2 080

[a]All are within either the Bisti or Star Lake areas. (Source: US Department of the Interior, Bureau of Land Management. 1976. *Coal: An Analysis of Preference Right Lease Applications for Federal Coal, p. 21.)*

Rock area, which contain strippable resources.[257] All are near the proposed spur, which will be built by the Santa Fe Railway Company. "In July, 1975, a Santa Fe subsidiary and Peabody-Thermal Energy Company entered into a Memorandum of Intent with Salt River Project to provide 86 million tons of coal for the Coronado Electric Generating Plant under construction at St. Johns, Arizona."[258] Santa Fe's resources should greatly exceed this commitment.

Future Development. Transportation is critical to the future development of the coals in the San Juan region. The very large-scale developments that have been proposed in addition to those already in the northwest section of the region are stagnated, and the leaseholders lack any transportation system capable of moving the coal out of the region. If the Star Lake spur is built, however (and there is every indication that construction will start soon), the southern area of the region will be opened up for the first time to large-scale production. Both the Gallup and Star Lake areas look very good for large-scale production efforts in the near future.

2.5.4. Western Colorado Coalfields.

Location. The Sego, Utah, and Book Cliffs, Colorado, coalfield group is an eastward continuation of the prominent Book Cliffs, which run from

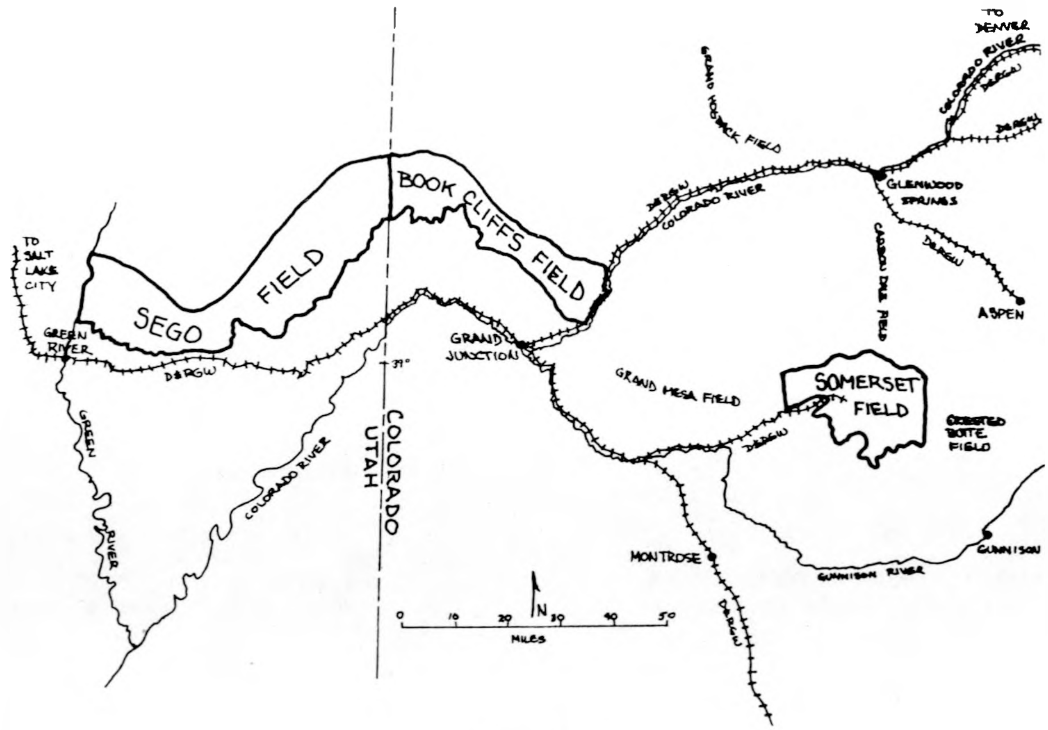


Fig. 2-10.
Western Colorado coalfields.

the Price River Canyon on the west to beyond Grand Junction, Colorado, in the east (Fig. 2-10). The Green River is used here as the dividing line between the Book Cliffs and the Sego coalfields in Utah. The Book Cliffs coalfield of Colorado begins at the Utah-Colorado border and runs along the cliffs to the Colorado River, across which begins the Grand Mesa coalfield. The Somerset field is farther east along the southern edge of the Uinta-Piceance Creek Basin, but is considered to be part of the Southeast Uinta Sub-Region.[259] Total length of the Sego-Book Cliffs field is nearly 110 miles; the Somerset Field is only 25 miles long. Both are only 5 to 10 miles wide.

Topography and Climate. The Sego-Book Cliffs coalfield, as part of the Book Cliffs, rises from elevations of 4500 to 6000 ft near the base of the cliffs, to 8000 to 9000 ft at the drainage divide.[260] The cliffs are alternately steep cliffs and slopes, forming a step-like rise to the Roan Plateau above. Many canyons cut through the cliffs, giving access to the coal seams, although the primary drainage of the plateau is northward. The field group is bounded and drained by the Green and Colorado Rivers. The Somerset field is located in more rugged topography where the Book Cliffs end and the coal-bearing rocks become more deformed and altered by intrusive rocks. This field is drained by tributaries of the Gunnison River, which itself is tributary to the Colorado River.

The area's climate varies from arid to nearly alpine, depending primarily on elevation. In the west the precipitation at the base of the cliffs is about 6 to 8 in. annually and 15 to 20 in. atop the plateau.[260] In the east near Somerset, the precipitation is somewhat higher. Annual precipitation peaks occur in winter and summer. Total annual precipitation can vary tremendously from one year to the next.

History. The Sego field in Utah has no active mines, although modest amounts of coal were produced in the first half of this century.[260] Table 2-23 lists the current and past coal production for all fields in the area. The Book Cliffs field in Colorado has one active mine, although the field's largest producing mine, opened in 1899, has only recently

TABLE 2-23

COAL PRODUCTION FROM WESTERN COLORADO COALFIELDS, 1975

Field	Active Mines	Mining Type	Production (Thousands of Short Tons)	Approximate Cumulative Production (Thousands of Short Tons)
Sego, Utah[a]	0	UG	0	2 650
Book Cliffs[b]	1	UG	76	4 344[c]
Somerset[b]	4	UG	1 297	27 562[c]

[a]Reference 260, p. 195.
[b]Reference 272, p. 16-21.
[c]Reference 261, p. 8-24.

shut down.[261] The Somerset field, because of its quality coking coal, has been a large producer since 1888. The U. S. Steel Corporation Somerset Mine, opened in 1903, has produced nearly 20 Mton.[262]

Transportation and Population. By far the largest population center in the region is Grand Junction, Colorado (19 300), Green River (1033) and Moab (4793), Utah, are to the west near the base of the cliffs, and Delta (3832) and Somerset (150), Colorado, to the east. The mainline of the Rio Grande Railroad from Salt Lake City passes through Green River, Utah, and continues eastward through Grand Junction, Colorado, below the Book Cliffs. The mainline to Denver continues along the Colorado River, while a spur line follows the Gunnison River valley to Delta, where it splits, one spur to serve the Somerset field. Interstate 70 parallels the Rio Grande mainline most of the way to Denver, and state highways serve the Somerset field.

Geology and Deposits. In the Sego coalfield, the most important coal is entirely contained within the Nelsen Member of the Upper Cretaceous Price River Formation, part of the Mesaverde Group.[263] These coals are younger than those of the Blackhawk Formation in the Book Cliff field, Utah, and, as the Cretaceous Mancos Sea slowly retreated farther to the east, the swamp and lagoonal environments conducive to the formation of peat also moved east. Thus, coal in the Book Cliffs field, Colorado, is found in the younger Mount Garfield Formation of the Mesaverde Group and in a tongue of the Mancos Shale.[264] Younger still are the coals in the lower Bowie Member and the upper Paonia Member of the Mesaverde Group in the Somerset field.[265]

Coal up to 7 ft 7 in. is found in the Thompson Canyon area of the Sego field,[266] and there are few faults or steep dips to complicate mining.[263] From the bottom up, the "Anchor" (6 ft 2 in.), "Palisade" (2 ft 8 in. to 9 ft 4 in.), "Carbonera" (7 ft 6 in. to 8 ft 6 in.), and "Cameo" (3 ft 6 in. to 10 ft 5 in.) seams are important in the Book Cliffs field.[264] In the Somerset field the coals in the east are moderately to strongly coking, whereas those to the west are noncoking high-volatile C and B bituminous.[265] The Bowie coals are 8 ft 6 in. to 17 ft 8 in. thick, whereas the Paonia coals are from 12 ft 0 in. to 13 ft 0 in. thick.

Quality. Table 2-24 lists the coal quality data for the important seams in the western Colorado coalfields. For the most part, these coals are low in sulfur and medium to high in ash. Most Colorado coals reportedly contain a large amount of pyritic sulfur in relation to organic sulfur and are thus able to be cleaned to below 0.5% sulfur.[267]

Resources. The coal resources of Colorado have been estimated as either "measured and indicated" or as "inferred." The first designation is limited generally to those areas within 0.75 mile of a coal observation point, while the second encompasses those areas more than 0.75 mile but less than 1 to 2

TABLE 2-24

WESTERN COLORADO COALFIELD QUALITY DATA

Field/Seam	Moisture (%)	Ash (%)	Sulfur (%)	Heat Content (Btu/lb.)
Sego[a]				
Neslen	9.1	11.1	0.60	10,940
Book Cliffs[b]				
Anchor	8.2-9.8	5.9-9.8	1.0-1.7	11 910-12 330
Palisade	3.3-14.0	4.9-17.4	0.5-1.6	10 950-13 560
Carbonera	9.3-11.4	7.2-14.4	0.4-0.6	10 470-11 150
Cameo	5.4-11.5	5.2-15.5	0.5-1.3	10 410-12 460
Somerset[c]				
Bowie	7.4-13.6	2.4-11.4	0.5-0.8	10 040-12 600
Paonia	10.6-22.4	4.3-13.9	0.3-0.8	8 160-10 610

[a]Reference 260, p. 210.
[b]Reference 264.
[c]Reference 265.

TABLE 2-25

ESTIMATED COAL RESOURCES OF WESTERN COLORADO COALFIELDS

Field	Measured and Indicated (Millions of Short Tons)	Inferred (Millions of Short Tons)	Remarks
Sego, Utah[a]	271	234	Bituminous
Book Cliffs, Colorado[b]	2 294	1 300	Bituminous
Somerset, Colorado[c]	3 348	2 190	Bituminous >50% Coking Quality

[a]Reference 260, p. 210.

[b]Reference 259.

[c]Ibid., p. 476.

miles from a point of direct observation.[269] The estimated coal resources of the western Colorado coalfields are given in Table 2-25. Although these numbers appear very large, probably no more than 10 to 15% of the measured-and-indicated class can be considered as economically recoverable at present. Actual recoverable reserves are unknown, although an estimate of 130 Mton of recoverable coal has been made for Sego field.[268]

Mineability and Production Costs. Coal deposits in the Sego-Book Cliffs coalfield group are rather thin and impure compared with many other areas, and it may be difficult to develop enough reserve to justify opening a large mine. Longwall equipment might prove ideally suited to the gently dipping, relatively unfaulted deposits,[270] and the deposits are very close to rail transportation. Washing of the coal, however, will probably be necessary. Sixty-one thousand tons of coal mined for the Cameo Power Plant near the Book Cliffs field sold for $9.50 per ton (46.17¢/mmBtu) in 1975.[271] We estimate that a large underground mine could have sold steam coal for about $12 per ton (54.55¢/mmBtu) in 1975.

Mines in the noncoking western coals of the Somerset field have not produced recently and little is known about the possible prices of coal from the area. Dips in the area should be gentle but faulting might present problems. Transportation may add expense to those mines in the west that are some distance from the railroad spur. We estimate that a large mine could have sold steam coal for about $14 per ton (60.87¢/mmBtu) in 1975.

Resource Ownership. Determining coal resource ownership in Colorado is very difficult because a large proportion of the state's coal lands are under private ownership. Current (1973) large federal coal leaseholders in the Somerset and Book Cliffs fields are listed in Table 2-26, along with pending federal preference-right lease applications for the State of Colorado. Some, but not all, of these applications are within these coalfields. There are no federal leases in the Sego field, Utah.

Future Development. The Somerset field is preparing for increased production in the near future as exploration and development on a number of new or rehabilitated mines is being undertaken.[272] Steady increases are expected in the production of good-quality coking coal. The one active mine in the Book Cliffs field has recently been rehabilitated both above and below ground and a second mine is preparing to reopen.[273] Neither area, however, appears prepared to develop the capacity necessary to meet the demands of a 1000-MWe power plant in the near future.

2.5.5. Northwestern Colorado Coalfields.

Location. The Grand Hogback-Carbondale field group lies along the eastern edge of the Uinta-Piceance Creek Basin and is split by the Colorado River (Fig. 2-11). Although the Carbondale field is considered part of the southeast Uinta subregion and the Grand Hogback field is in the northeast Uinta subregion,[274] the fields are considered together here because of their proximity to each other and to the mainline of the Rio Grande Railroad. The Yampa field is the only Green River region field in Colorado, extending under a large portion of Moffat, Routt, and Rio Blanco Counties in extreme northwestern Colorado.

Topography and Climate. The Colorado River flows across the eastern edge of the Uinta-Piceance Creek Basin at about 5500 ft while passing through highlands of up to 9500 ft. North of the river the prominent Grand Hogback Ridge reflects topographically the steeply dipping beds. The Yampa field is generally rolling terrain of 6000 to 9000 ft, although more rugged topography exists in the southeast. The field is drained by the Yampa

TABLE 2-26

WESTERN COLORADO FEDERAL COAL LAND HOLDERS WITH LARGE ACREAGES

A. Coal Lands Leaseholders (1973)[a]

Somerset Field

Atlantic Richfield Company Dallas, Texas	U.S. Steel Corporation Pittsburgh, Pennsylvania

Book Cliffs Field

Industrial Resources, Inc. Denver, Colorado	Mid-Continent Limestone Company Glenwood Springs, Colorado
James Brothers Coal Company Magnolia, Ohio	Pitkin Iron Corporation Glenwood Springs, Colorado
Juanita Coal and Coke Company Paonia, Colorado	Reance Exploration, Inc. West Hempstead, New York

B. Colorado Preference-Right Lease Applications (1976)[b]

Applicant	Number of PRLAs	Acreage under PRLAs
Mobil Oil Corporation	9	26 891
Geralt T. Tresner	3	14 729
Mintech Corporation	8	14 314
Consolidation Coal Company	6	11 645
The Kemmerer Coal Company	5	9 866
Ember Mining Company	3	9 626
Moon Lake Electric Association, Inc.	2	3 112
Utah International, Inc.	1	2 081
L. C. Craig	1	640
Phillip A. Jensen	1	480
Morgan Coal Company	1	475
Staley-Gordon Coal Company, Inc.	1	259
Total	41	94 118

[a]Reference 215, p. 56-69.

[b]U.S. Department of the Interior, Bureau of Land Management. 1976. *Coal - An Analysis of Preference Right Lease Applications for Federal Coal, p. 20.*

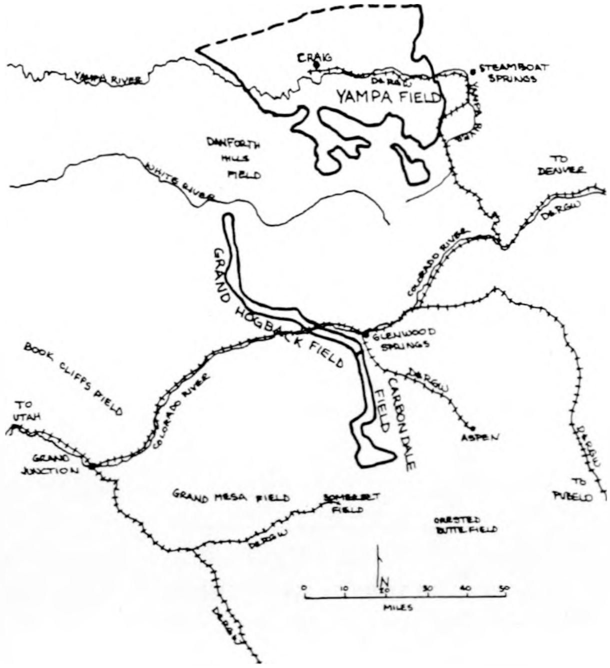


Fig. 2-11.
Northwestern Colorado coalfields.

River and its tributaries, water that eventually reaches the Green River in Utah. Precipitation is about 14 in. per year at Craig in the Yampa field, and about the same in the Grand Hogback-Carbondale area.[275]

History. The Grand Hogback field has only one producing mine, which opened in 1968, and the field has seen only limited production (Table 2-27). In contrast, however, the coking-quality coal in the Carbondale field has been mined since 1888 and is still being produced from relatively new mines.[276] At present, the largest producing field in Colorado is the Yampa field, which has had underground production since the 1920s and surface production since 1945.[276] The active surface mines started production during three periods: in 1945, in mid-1960, and after 1970.

Transportation and Population. The largest town in the Grand Hogback-Carbondale region is Glenwood Springs (3673), about 10 miles east of the coalfields on the route of both Interstate 70 and the Rio Grande Railroad mainline from Salt Lake City to Denver. Carbondale (612) is about 12 miles south of Glenwood Springs on the Rio Grande spur line, which serves Aspen.

Craig (3984) is the population center for the Yampa field and is served by a spur of the Rio Grande Railway, which connects with the mainline just east of Glenwood Springs. US Highway 40 from Vernal follows the Yampa River up through Craig and on to Steamboat Springs (1843), which lies outside the coalfield. While traveling south, the railroad once again passes through the field near Routt and

TABLE 2-27

COAL PRODUCTION FROM NORTHWESTERN COLORADO COALFIELDS

	1975[a]			Approximate Cumulative
Field	**Active Mines**	**Type Mining**	**Production**	**Production[a,b]**
			(1 000 Short Tons)	
Grand Hogback	1	Underground	0.5	5
Carbondale	6	Underground	928	19 527
Yampa	9	Surface (8)		
		Underground (1) 4	674	63 531

[a]Reference 272, p. 16-21.

[b]Reference 276.

Oak Creek. The spur is approximately 125 miles long and travels through rather rugged terrain.

Geology and Deposits. Coal is found in the Upper Cretaceous Mesaverde Group in both the Grand Hogback and Carbondale fields. In the Grand Hogback area, significant seams occur primarily in the upper Williams Fork Formation, although locally the "Black Diamond" group in the lower Iles Formation contains mineable coals.[277] Nine seams, forming the "middle group" in the Williams Fork Formation, are the most important, with the "Wheeler seam" (14 ft 0 in. to 18 ft 0 in.) and the "Allen seam" (5 ft 6 in. to 15 ft 6 in.) being the primary producers.

At Carbondale, the rocks are roughly correlated with the coalbearing strata in the Grand Hogback field. The structure is transitional between the highly faulted, folded, and metamorphosed coal sections to the south and the steeply dipping monocline of the Grand Hogback field.[278] In the south, the coals have been altered up in rank to high-volatile A bituminous, medium-volatile bituminous, and even anthracite, and are moderately to strongly coking. In the north, the coals are predominantly noncoking high-volatile B bituminous. The Black Diamond seam (4 ft 0 in. to 16 ft 0 in.) and three seams in the Williams Fork Formation (4 ft 0 in. to 11 ft 6 in.) are the most persistent and highest in quality.

In the Yampa field, important seams are found in the Upper Cretaceous Mesaverde Group and Lance Formation and the Paleocene Fort Union Formation.[279] In the upper Iles Formation the Black Diamond group achieves thicknesses of 3 ft 8 in. to 12 ft 4 in. The Fairfield (3 ft 0 in. to 42 ft 0 in.) and Twenty-Mile (4 ft 4 in. to 10 ft 4 in.) groups occur in the lower and upper portions of the Williams Fork Formation, respectively. The Lance Formation (7 ft 6 in. to 11 ft 9 in.) and the Fort Union Formation (6 ft 0 in. to 17 ft 0 in.) contain subbituminous B or C coals.

Quality. Coal quality data for these northwestern Colorado coalfields are given in Table 2-28. In general, these coals have low to medium ash content and low to very low sulfur content. The younger coals are normally lower quality than those of the Mesaverde Group. Most Colorado coals reportedly contain a large amount of pyritic sulfur in relation to organic sulfur, and are thus able to be cleaned to below 0.5% sulfur.[267]

Resources. The coal resources of Colorado have been estimated as either "measured and indicated" or "inferred." The first is limited generally to those areas within 0.75 mile of a coal observation point, while the second encompasses those areas more than 0.75 mile but generally less than 1 to 2 miles from a point of direct observation.[269] The estimated coal resources of the northwestern Colorado coalfields are given in Table 2-29. Although these numbers appear very large, probably no more than 10 to 15% of the measured-and-indicated class can be considered as economically recoverable at present. Actual recoverable reserves are unknown.

Mineability and Production Costs. In the Carbondale-Grand Hogback field there is no activity upon which to base an estimate of coal production costs. Dips along the Grand Hogback are often very steep, and the Carbondale field is in part highly faulted. Longwall units are currently being installed in the southern part of the Carbondale field[280] in mines with up to 30° dips; this holds promise for more efficient mining in the future. The estimate is that a large underground mine in these fields could have sold steam coal for about $14 (58.33¢/mmBtu) per ton in 1975.

Strip coal in the Yampa field was being sold in 1975 for over $12 per ton, except in one instance, where the price was slightly over $5 per ton.[280] Production costs are likely much lower than this $12 per ton indicates, although they are probably over $5 per ton. Strippable deposits are somewhat scattered and far from rail transportation. We estimate that a large surface mine could have sold steam coal for about $7 per ton (33.02¢/mmBtu) in 1975.

Resource Ownership. Determining coal resource ownership in Colorado is very difficult because a large proportion of the state's coal lands is under private control. Large acreage lessees of federal coal lands in the Yampa field are listed in Table 2-30, along with pending federal preference-right lease applications for the State of Colorado. Some, but not all, of these applications are in northwestern Colorado. There are no current (1973) large federal leases in the Grand Hogback field, nor any in the northern half of the Carbondale field.[281]

Future Development. The Yampa field is the largest producer in Colorado, and most of its strip

TABLE 2-28

NORTHWESTERN COLORADO COALFIELD
QUALITY DATA

Field/Seam	Moisture (%)	Ash (%)	Sulfur (%)	Btu/lb.
Grand Hogback[a]				
Wheeler	3.4-8.3	4.9-11.3	0.3-0.8	11 220-13 120
Allen	3.5-10.7	3.9-7.9	0.4-0.5	11 600-13 270
Carbondale[b]				
Black Diamond	11.4-14.1	2.1-9.2	0.5-1.4	10 360-12 310
Williams Fork	3.8-7.5	1.9-10.5	0.4-1.5	11 840-13 530
Yampa[c]				
Black Diamond	6.3-12.2	4.3-11.3	0.3-0.9	11 090-12 560
Fairfield	7.7-11.8	3.4-11.5	0.3-0.6	10 740-12 260
Twenty-mile	14.2-16.9	4.1-5.4	0.4-0.9	10 360-11 040
Lance	19.6-21.8	4.1-6.5	0.5-0.7	9 660- 9 720
Fort Union	17.1-20.5	3.9-7.8	0.2-0.4	9 500-10 080

[a]Reference 277.

[b]Reference 278.

[c]Reference 279.

TABLE 2-29

ESTIMATED COAL RESOURCES OF NORTHWESTERN COLORADO COALFIELDS

Resources with less than 3 000 feet of overburden

Field	Measured (Millions of Short Tons)	Inferred (Millions of Short Tons)	Remarks
Grand Hogback[a]	885	760	Bituminous
Carbondale[b]	1 136	1 870	Bituminous, 50% coking quality
Yampa[c]	23 607	21 300	3/4 Bituminous 1/4 Subbituminous 3 680 strippable

[a]Reference 277.

[b]Reference 278.

[c]Reference 279.

mines are newly opened. The transportation problem has been overcome in part with the construction of mine-mouth power plants, and almost all of the field's production is consumed within the state.[282] Production of steam electric coal from the field should increase solidly in the near future as the new mines increase production and out-of-state markets grow. Competition from the strip coals of southern Wyoming, which are much closer by rail to eastern markets, will be a large factor in keeping this growth slow.

The Carbondale field is also expanding to meet increased demand for coking coal,[278] all of which was shipped out of state in 1975.[282] The production of steam electric coal from this field and Grand Hogback to the north does not look imminent, however, because coal can apparently be produced for less from the nearby Yampa field. Thus, although it appears that both fields could supply the needs of a 1000-MWe power plant, mining and transportation costs will hinder the development of both for out-of-state markets.

TABLE 2-30

FEDERAL COAL LAND HOLDERS WITH LARGE ACREAGES IN NORTHWESTERN COLORADO

A. Coal Lands Leaseholders (1973)[a]

Yampa Field
Morgan Coal Company Indianapolis, Indiana
Peabody Coal Company St. Louis, Missouri
Pittsburgh and Midway Coal Mining Company Kansas City, Missouri
United Electric Coal Company Chicago, Illinois
Utah International, Inc. San Francisco, California

B. Colorado Preference-Right Lease Applications (1976)[b]

Applicant	Number of PRLAs	Acreage Under PRLAs
Mobil Oil Corporation	9	26 891
Geralt T. Tresner	3	14 729
Mintech Corporation	8	14 314
Consolidation Coal Company	6	11 645
The Kemmerer Coal Company	5	9 866
Ember Mining Company	3	9 626
Moon Lake Electric Association, Inc.	2	3 112
Utah International, Inc.	1	2 081
L. C. Craig	1	640
Phillip A. Jensen	1	480
Morgan Coal Company	1	475
Staley-Gordon Coal Company, Inc.	1	259
Total	41	94 118

[a]Reference 215, p. 56-69.

[b]US Department of the Interior, Bureau of Land Management. 1976. *Coal—An Analysis of Preference Right Lease Applications For Federal Coal, p. 20.*

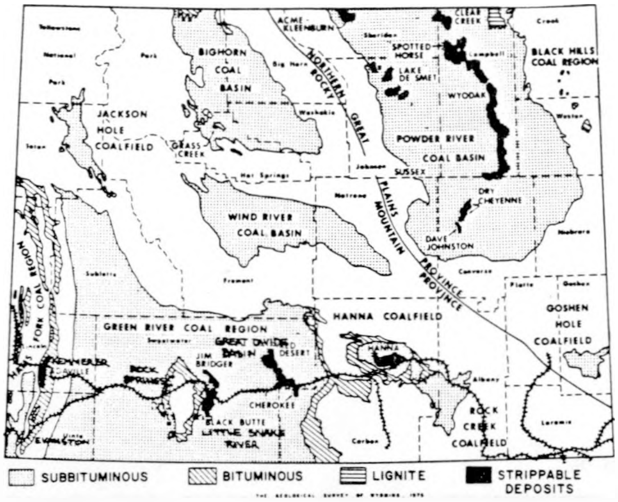


Fig. 2-12.
Southern Wyoming coalfields: (Source: Ref. 285, p. 1.)

TABLE 2-31

WYOMING STATEWIDE COAL PRODUCTION
1970-1980

Year	Production in Short Tons
1970[a]	7 380 930
1971	8 007 765
1972	10 920 468
1973	14 840 857
1974	20 649 754
1975	23 784 128
1976[b]	33 500 000
1977	51 400 000
1978	73 000 000
1979	89 200 000
1980	105 900 000

[a]1970-1975 actual production. Reference 283.

[b]1976-1980 predicted production based on announced contracts. Reference 292, p. 20.

2.5.6. Southern Wyoming Coalfields.

Location. The southern Wyoming coalfields considered in this study are the Kemmerer and Evanston coalfields of the Hams Fork coal region, the Rock Springs and Great Divide—Little Snake River coalfields of the Green River coal region, and the Hanna coalfield (Fig. 2-12). These fields underlie major portions of Lincoln, Uinta, Sweetwater, and Carbon Counties in southern Wyoming.

Topography and Climate. The area is predominantly high plains averaging about 7000 ft in elevation. The northern end of the Kemmerer field becomes mountainous, and more rugged topography is found around the Rock Springs Uplift and near the edges of the Hanna Basin. The Green River coal region is drained by the Green and Little Snake Rivers, and the Hanna coalfield by tributaries of the North Platte River. Great Divide Basin is a topographic depression of interior drainage bounded completely by the bifurcated Continental Divide. The area is very arid, receiving minimal rainfall and suffering from great temperature extremes and winds.

History. Coal has been produced in Wyoming for almost 100 yr, but only since 1970 has it boomed. After a production low of 1.6 Mton in 1958, output slowly gained momentum, reaching 4.6 Mton in 1969.[283] Table 2-31 shows the tremendous increase in production since 1970 and the predictions for continued growth through 1980. Study-area production in 1975 totaled 15 669 503 tons.[284]

Transportation and Population. The mainline of the Union Pacific Railroad, from Salt Lake City, Utah, to Cheyenne, Wyoming, bisects all the coalfields in the study area. As shown in Fig. 2-12, however, much of the coal lies more than 20 miles from the line. Spurs serve the Kemmerer and Rock Springs coalfields.

Major centers of population include Evanston (4462), Kemmerer (2292), Green River (4196), Rock Springs (12 000), and Rawlins (7855). All but Kemmerer lie along Interstate Highway 80, which basically parallels the mainline Union Pacific Railroad.

Geology and Deposits. The Kemmerer and Evanston coalfields of the Hams Fork region are the westernmost in Wyoming. The coal-bearing strata in this region, the Bear River, Frontier, and Adaville Formations of Upper Cretaceous age, and the Evanston Formation of Paleocene age, are highly folded and thrust-faulted.[285] The coal outcroppings thus occur in long, narrow belts.

The coals range in rank from subbituminous B to high-volatile A bituminous, the Frontier Formation seams being the highest ranking coals. The most important seams in the region are the Adaville seams, best developed in the Kemmerer field. At least 17 seams are over 6 ft thick, with the Adaville No. 1 seam occasionally over 100 ft thick. This seam contains some coal that is used to make chemical coke and some low-quality metallurgical coke. Partings are common in all of the Adaville seams.

The Rock Springs and Great Divide-Little Snake River coalfields compose the major portion of the Green River coal region. These two fields are separated by the Rock Springs Uplift, which creates dips of up to 20° in the nearby coal-bearing strata; small dips are normal for the rest of the region.[287] Coal beds occur in the Mesaverde Group and the Lance Formation of Upper Cretaceous age, the Fort Union Formation of Paleocene age, and the Wasatch Formation of Eocene age. Much of the coal-bearing strata are concealed under younger rocks.

Rock Springs Formation coals of the Mesaverde Group, historically the most important in the region, are high-volatile C bituminous and are up to 13.8 ft thick. Subbituminous Almond Formation coals of the Mesaverde Group are up to 12 ft thick on the east side of the uplift. Lance Formation coals are similarly thickest (5 to 10 ft) on the east. Fort Union Formation coals are often the thickest and most persistent in the region, averaging 10 to 26 ft, and up to 30 ft thick. In contrast, the Wasatch coals are lenticular, and, in the Great Divide Basin, grade to shale east and west.[288] Here they also contain unusually high uranium percentages (up to 0.009%).

The Hanna field occupies a structural trough bounded on the north, west, and south by mountain ranges.[286] Faulting is common in this field. Coal seams occur in the Mesaverde Group and Medicine Bow Formation of Upper Cretaceous age, the Ferris Formation of Upper Cretaceous to Paleocene age, and the Hanna Formation of Paleocene to Eocene age. The coals of the Mesaverde Group are highest in rank at high-volatile C bituminous, and rank ranges downward through the Medicine Bow Formation coals to subbituminous B. The younger coals are predominantly subbituminous. The important seams in the coalfield are listed in Table 2-32.

TABLE 2-32

IMPORTANT COAL SEAMS IN THE HANNA COALFIELD

Seam	Thickness (Ft)
Bed 24	18-20
Bed 25 (including partings)	22
Bed 50	15-19
Bed 65	6-8
Bed 80	15-24
Bed 82	9
Brooks Seam	7-15
Hanna 1	15-30
Hanna 2	30-36

(Source: Reference 285, p. 14-15)

Quality. Because of the great expanse of these regions and their tremendous number of deposits, it is difficult to come up with an average quality index. Table 2-33 shows that although western Wyoming coals are lower in moisture and ash, southern Wyoming coals are lower in sulfur and higher in heat value. The Wasatch Formation coals in the southern part of the Great Divide Basin are, however, very high in sulfur, averaging about 2.5%.[288]

Resources. Coal resources in the three southern Wyoming coal regions are listed in Table 2-34 by rank. The total of nearly 25 Bton is only a rough estimate based upon often incomplete data, especially in the Green River region. More important to near-term exploitation are the strippable resources listed in Table 2-35. The majority of the 2.5 Bton of remaining strippable coal should be recoverable, and, as shown in Fig. 2-12, is located within reasonable transportation distance of the Union Pacific Railroad.

Mineability and Production. Almost all of the coal that will be economically developed from southern Wyoming in the near future will be mined on the surface, although some underground mining will continue in the Rock Springs and Hanna coalfields. Thick, relatively high-quality seams close to the surface with easily removed overburden make

TABLE 2-33

QUALITY CHARACTERISTICS OF COALS AND IMPORTANT SEAMS IN WESTERN AND SOUTHERN WYOMING

Area or Seam	Rank	Average Thicknesses (Ft)	Moisture (%)	Ash (%)	Sulfur (%)	Heat (Btu/lb.)
Southern Wyoming[a]	Subbituminous Bituminous	4-35	12.4	7.1	0.52	10 500
Western Wyoming[a]	Subbituminous Bituminous	5-110	20.8	4.5	0.6	9 600
Adaville No. 1[b] (Hams Fork Region)	Subbituminous B	6-110	20.4	3.0	0.7	10 193
Deadman Seam[c] (Green River Region)	Subbituminous	15-30	20.5	9.7	0.47	9 350
Bed No. 24[d] (Hanna Field)	Subbituminous	18-20	14.0-16.0	3.9-8.4	0.3-0.4	10 050-10 180
Bed No. 80[e] (Hanna Field)	Subbituminous	15-24	11.5	6.6	0.9	10 665
Hanna No. 2[e] (Hanna Field)	Subbituminous A	30-36	10.2	5.8	0.37	11 350

[a]Reference 285, p. 3.
[b]Ibid., p. 16.
[c]Ibid., p. 12.
[d]Ibid., p. 14.
[e]Ibid., p. 15.

coal from southern Wyoming some of the least expensive to mine in the United States. The average price in 1975 for steam electric coal delivered to utilities in quantities of over 1 Mton per year from Wyoming was about $7.21 per ton or $0.4144 per MBtu.[289] For these six power plants the price ranged from $15.44 per ton ($0.8020 per MBtu) down to $2.39 per ton ($0.1678 per MBtu). Table 2-36 lists the estimated selling price of steam coal mined in each of the southern Wyoming coalfields in 1975.

Resource Ownership. The overwhelming majority of the coal lands in southern Wyoming is controlled by the US Bureau of Land Management and the Rocky Mountain Energy Company. Rocky Mountain Energy (Denver, Colorado) is a wholly owned subsidiary of the Union Pacific Railroad and is sole agent for coal resources under the railroad's lands, the alternating sections for 20 miles on either side of the Union Pacific tracks. Major federal coal leases in southern Wyoming were held, in 1973, by the ten companies listed in Table 2-37. Many of these lessees are now and have been producing from their leases. State coal lands are essentially all leased but are only a small percentage of total coal lands.[290] Usually a combination of federal, private,

TABLE 2-34

ESTIMATED ORIGINAL COAL RESOURCES IN SOUTHERN WYOMING BY REGION AND RANK[a]

Coal-Bearing Region	Bituminous	Subbituminous	Total
Green River Coal Region	9 904.84	6 051.04	15 955.88
Hams Fork Coal Region	3 197.68	1 676.86	4 874.54
Hanna Coalfield	73.44	3 843.52	3 916.96
Total	13 175.96	11 571.42	24 747.38

[a]Includes mapped and explored bituminous seams 14 in. or greater in thickness and subbituminous coals 2.5 ft and thicker with overburden limits of 3 000 ft in millions of short tons. Source: Ref. 285, Table 4, p. 17.

and state coal lands is necessary to bring together a contiguous block of coal great enough to develop a large surface mine.

Future Development. Predictions for growth in Wyoming's coal industry are universal, with production estimates of 60 to 110 Mton annually by 1980, and up to 200 Mton by 2000.[291] Much of this growth will take place in southern Wyoming, where relatively good quality, inexpensive production costs, and optimal proximity to good rail transportation make this coal very attractive. Rocky Mountain Energy Company is actively seeking new markets, as are other producers with surplus capacity.[292] Prices can be expected to rise, although large, long-term contracts will command the best terms.

2.6. Summary

Coal has formed slowly over many millions of years from the accumulated remains of ancient plants. Coal can vary widely in rank, heat content, sulfur, ash, and trace metals, all of which will have some bearing on its desirability for use as a fuel for electric power generation. The current estimates for total US coal resources is nearly 4 million Mton (4×10^{12} tons); however, only about 5.5% (219 000 Mton) is currently economically recoverable. The price of coal nationwide has been rising rapidly in the last few years, even though the percentage of production by cheaper strip mining techniques has been increasing.

The area of analysis for this coal supply study included all coalfields within 800 miles of Los Angeles. Initial analysis of the 92 coalfields within this area concentrated on total recoverable reserves, proximity to transportation, coal quality, and mineability and development status. A 1000-MWe coal-fired power plant will require nearly 100 Mton of coal over its lifetime, all of which must be transported from mine mouth to power plant. Over long distances only railroads and, in some instances, slurry pipelines have proved economically feasible. After evaluating each coalfield by these criteria, 69 coalfields were rejected as probable coal sources for this power plant. Most were rejected because of insufficient reserves; the rest were rejected for multiple reasons, including no or poor rail transportation, difficult mining or poor quality, and little information. The remaining coalfields, or groups of coalfields, shown in Fig. 2-13, were examined in much greater detail.

Most of the coal lands selected as possible coal sources are under federal control. The Department of the Interior has recently issued new regulations concerning the leasing of such coal lands, and Congress has also enacted new legislation dealing with the leasing of federal coal lands. Although there are confusing differences between the two programs,

TABLE 2-35

REMAINING STRIPPABLE SUBBITUMINOUS COAL RESOURCES OF SOUTHERN WYOMING TO JANUARY 1, 1974

Coal-Bearing Region	Strippable Deposit	Coal Bed(s) (Av thick-ness, ft)	Acreage Estimate	Original Estimated Resources to Jan. 1, 1968	Production and Mining Losses Since Jan. 1, 1968	Remaining Strip-pable Resources to Jan. 1, 1974
				(short tons)	(short tons)	(short tons)
Green River Coal Region	Black Buttes	Almond, Lance, Ft. Union, and Wasatch Fm. coals (12 ft)	3 889.0	82 600 000		
	Cherokee	B (10 ft) C (17 ft)	4 204.00	200 900 000		
	Jim Bridger	Deadman (30 ft)	4 708.0	250 000 000		
	Red Desert (very high sulfur)	Battle 2 and 3 (7 ft)	2 938.0	38 100 000		
		Sourdough, Monument, and Tierney (6.8 ft)	27 469.0	458 900 000		
		Hadsell 2 (7.7 ft)	2 874.0	39 800 000		
		Creston 2 and 3 (14 ft)	3 846.0	125 600 000		
		Latham 3 and 4 (5.7 ft)	6 893.0	70 700 000		
		Subtotal	56 821.0	1 266 600 000	34 483	1 266 565 517
Ham's Fork Coal Region	Adaville	Adaville Fm. coals (44 ft)	12 800.0	1 000 000 000		
		Subtotal	12 800.0	1 000 000 000	13 977 597	986 022 403
Hanna Coal-field	Hanna	Hanna, Ferris, and Medicine Fm. coals (21 ft)	8 400.0	313 000 000		
		Subtotal	8 400.0	313 000 000	30 963 626[a]	282 036 374
		Grand total	78 021.0	2 579 600 000	40 975 706	2 538 624 294

[a]This is strip production and mining losses since 1950.

(Source: Ref. 285, Table 7, p. 19)

both are designed to tighten federal leasing requirements, specifically in regard to diligent development and continuous production. These and other requirements were enacted to stop speculation in federal coal lands and to force timely development. Because, in many cases, they will be applicable to existing, as well as new or future leases, the result might be a push for development by current leaseholders.

Coal from Indian lands is obtained either through competitive bidding or negotiation, but in either case, political realities are apt to be of much more concern than local limitations. State lands are generally noncontiguous individual sections spread among the vast federal lands, and are thus most important in completing acreage for an economic development. Private lands are significant in only a few rare instances and must be individually negotiated for lease rights.

Although the costs of strip mined coal are currently well below that of underground mined coal, costs are likely to be substantially increased if federal strip mining legislation is enacted. Passage of tough strip mining legislation was imminent throughout 1976, and its failure during this year may only imply that greater pressure will be brought to bear in 1977. This will be of particular importance in many Western States where coal underlies irrigable alluvial valley floors. The probability that stringent reclamation and environmental protection regulations will be enacted is very high, implying that any coal source to be developed by surface mining should

TABLE 2-36

APPROXIMATE PRICE OF COAL FROM SOUTHERN WYOMING COALFIELDS

Field	Dollars (Ton)	Dollars (mBtu)	Mining Method
Kemmerer[a]	7.09	0.3662	Surface
Evanston[b]	12.00	0.5742	Underground
Rock Springs[c]	4.55	0.2472	Surface
Great Divide and Little Snake River[d]	5.00	0.2381	Surface
Hanna[e]	5.00	0.2381	Surface

[a]Price of 1 719 000 tons of steam coal delivered in 1975. Ref. 210, p. 100.

[b]Based on the higher costs of underground mining and the lack of previous large-scale mining.

[c]Price of 1 863 000 tons of steam coal delivered in 1975. Ref. 210, p. 100.

[d]Assumed same as Hanna although mining costs will differ slightly.

[e]Estimated to be slightly greater than Rock Springs. Actual field production is dispersed throughout west and midwest. Ref. 210, p. 96-100.

TABLE 2-37

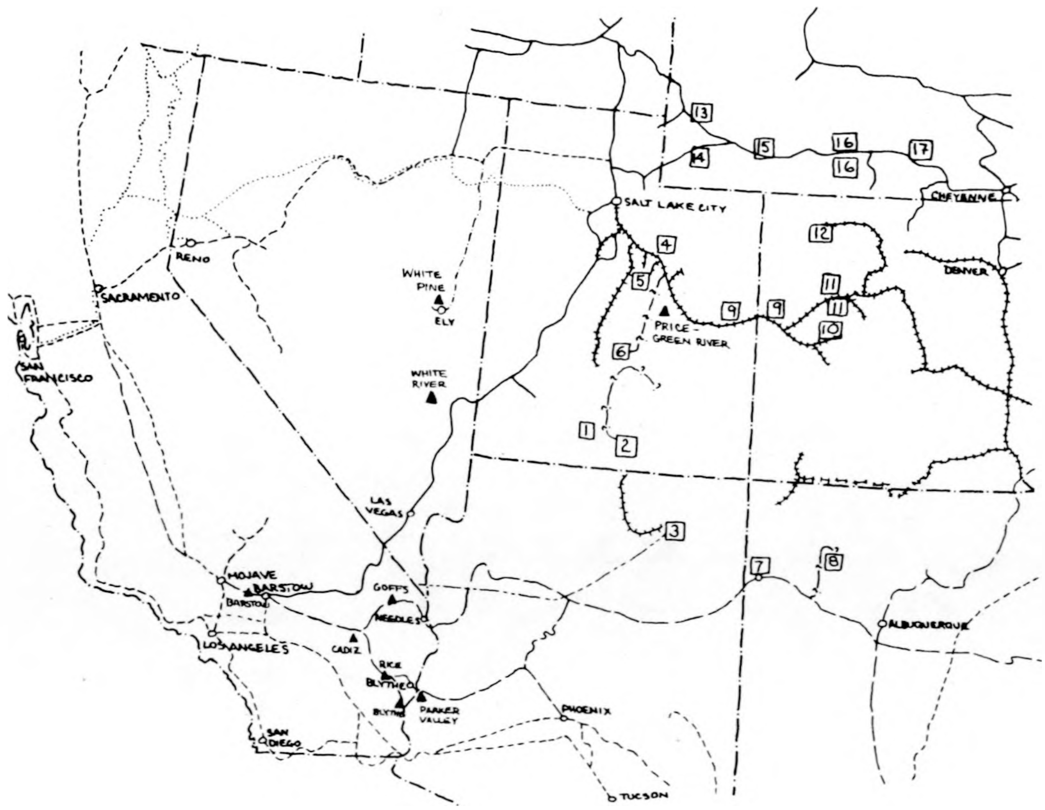
MAJOR FEDERAL COAL LEASEHOLDERS IN SOUTHERN WYOMING, 1975

Lessee	County
Kemmerer Coal Company Frontier, Wyoming	Lincoln
Badger Service Company Milwaukee, Wisconsin	Sweetwater
Gunn-Quealy Coal Company Frontier, Wyoming	Sweetwater
Sun Oil Company Dallas, Texas	Sweetwater
Pacific Power and Light Company Portland, Oregon	Sweetwater Carbon
Rosebud Coal Sales Company Sheridan, Wyoming	Carbon
Energy Development Company Sioux City, Iowa	Carbon
Ark Land Company St. Louis, Missouri	Carbon
FMC Corporation Pocatello, Idaho	Uinta Lincoln
Peabody Coal Company St. Louis, Missouri	Sweetwater

[a](Source: Ref. 215, p. 113-127)

be investigated carefully to establish how tighter federal controls may escalate its costs. The existing practice under federal coal leases is to require compliance with the law of the state in which mining is being performed unless federal regulations are more stringent. The states under study in this report have all enacted strip mining reclamation laws, which vary widely both in detail and requirements.

The main text contains detailed summaries of the coal resources in each of the 17 possible coal sources. Table 2-38 is a summary of the coal quality and cost information developed for each field or field group. This information has been used in the cost model (Sec. 4) to rank by cost all the alternative scenarios. There are many considerations, however, that cannot be used in a cost model but will be ultimately of equal or greater importance in determining both the cost and timing of coal supply development. These factors, such as transportation access, resource availability, current state of resource development, and sociopolitical considerations, are much more difficult to assess and summarize. A qualitative ranking of the six coal supply regions, based only on these noncost factors, is given in Table 2-39.



Southwestern Railroads and Coalfields

Selected Possible Powerplant Sites

Railroads

Atchison, Topeka and Santa Fe
Denver and Rio Grande Western
Nevada Northern
Southern Pacific
Union Pacific
Western Pacific
Black Mesa and Lake Powell
Proposed Extensions
Black Mesa Coal Slurry Pipeline

Coalfields

I. Southwestern Utah and Arizona
- 1 Alton, Utah
- 2 Kaiparowits Plateau, Utah
- 3 Black Mesa, Arizona

II. Central Utah
- 4 Book Cliffs, Utah
- 5 Wasatch Plateau, Utah
- 6 Emery, Utah

III. New Mexico
- 7 Gallup, New Mexico
- 8 Star Lake, New Mexico (Includes portions of: Bisti, New Mexico; Chaco Canyon, New Mexico; Standing Rock, New Mexico; Crownpoint, New Mexico)

IV. Western Colorado
- 9 Sego, Utah and Book Cliffs, Colorado
- 10 Somerset, Colorado

V. Northwestern Colorado
- 11 Grand Hogback, Colorado, and Carbondale, Colorado
- 12 Yampa, Colorado

VI. Southern Wyoming
- 13 Kemmerer, Wyoming
- 14 Evanston, Wyoming
- 15 Rock Springs, Wyoming
- 16 Great Divide, Wyoming, and Little Snake River, Wyoming
- 17 Hanna, Wyoming

Fig. 2-13.
Southwestern railroads and coalfields.

TABLE 2-38

SUMMARY OF COAL SOURCE QUALITY AND COST

Field	Mining Method	Ash (%)	Sulfur (%)	Heat Content (Btu/lb)	Estimated 1976 Cost (f.o.b. mine) ($/ton)	($/mmBtu)
1. Alton, Utah	Surf	9.6	1.3	10 772	5.00	0.2321
2. Kaiparowits Plateau, Utah	UG	8.96	0.87	11 999	11.00	0.4584
3. Black Mesa, Arizona	Surf	10.9	0.40	10 825	3.09	0.1426
4. Book Cliffs, Utah	UG	6.7	0.85	12 762	10.00	0.3918
5. Wasatch Plateau, Utah	UG	6.5	0.60	12 589	10.00	0.3972
6. Emery, Utah	UG	8.9	0.99	11 424	12.00	0.4814
7. Gallup, New Mexico	Surf	7.95	0.42	10 637	6.00	0.2820
8. Star Lake, New Mexico	Surf	20	0.6	9 500	4.50	0.2368
9. Sego, Utah Book Cliffs, Colorado	UG	11.1	0.60	11 000	12.00	0.5455
10. Somerset, Colorado	UG	8	0.6	11 500	14.00	0.6087
11. Grand Hogback, Colorado Carbondale, Colorado	UG	8	0.6	12 000	14.00	0.5833
12. Yampa, Colorado	Surf	10.53	0.47	10 598	7.00	0.3302
13. Kemmerer, Wyoming	Surf	4.89	0.50	9 683	7.09	0.3662
14. Evanston, Wyoming	UG	7.2	0.4	10 450	12.00	0.5742
15. Rock Springs, Wyoming	Surf	10.58	0.60	9 210	4.55	0.2472
16. Great Divide, Wyoming Little Snake River, Wyoming	Surf	10	0.9	10 500	5.00	0.2381
17. Hanna, Wyoming	Surf	6	0.6	10 500	5.00	0.2381

TABLE 2-39

QUALITATIVE RANKING OF THE SIX POSSIBLE COAL SOURCE REGIONS

No.	Region
1.	Central Utah coalfields
2.	Wyoming coalfields
3.	New Mexico coalfields
4.	Southern Utah and Arizona coalfields
5.	Northwestern Colorado coalfields
6.	Western Colorado coalfields

REFERENCE NOTES

1. Section 2.1 is in major part an adaptation of *Final Environmental Impact Statement: Proposed Federal Coal Leasing Program,* US Department of Interior, Bureau of Land Management (US Government Printing Office, Washington, DC, 1975), pp. 1-32 to 1-45.

2. *Glossary of Geology*, Margaret Gary, Robert McAfee, Jr., and Carol L. Wolf, Eds. (American Geological Institute, Washington, DC, 1972), p. 135.

3. Peat is "an unconsolidated deposit of semi-carbonized plant remains of a water saturated environment, such as a bog or fen, and of persistently high moisture content (at least 75%)," *Glossary of Geology,* p. 521.

4. "It has been estimated that a foot of bituminous coal contains plant material accumulated over a period of several centuries." Paul Averitt, "Coal Resources of the United States, January 1, 1967," in US Geological Survey Bulletin 1275 (US Government Printing Office, Washington, DC, 1969), p. 16.

5. More localized increases in both temperature and pressure can result from either nearby igneous intrusions or structural deformation.

6. Table 2-1 is reproduced from Jack A. Simon and M. E. Hopkins, "Geology of Coal," in *Elements of Practical Coal Mining,* S. M. Cassidy, Ed. (Society of Mining Engineers of the American Institute of Mining, Metallurgical and Petroleum Engineers, Inc., New York, 1973), Table I, p. 22-23.

7. Coke is a combustible material consisting of the fused ash and fixed-carbon of bituminous coal, produced by driving off by heat the coal's volatile matter. It is gray, hard, and porous, and as a fuel it is practically smokeless. Although it is still unknown what specific properties of a coal allow it to coke, in general it must be able to fuse and have low sulfur and ash contents.

8. Table B is reproduced from Ref. 1, p. 1-41 and 1-42, and from a US Department of Interior News Release, April 15, 1974, "New Mineral Resource Terminology Adopted."

9. *Final Environmental Impact Statement: Proposed Federal Coal Leasing Program,* Table 1-11, p. 1-42.

10. Ibid, p. 1-39 and Table 1-11, p. 1-42.

11. L. Westerstrom, "Coal-Bituminous and Lignite," in *Minerals Yearbook 1973, Vol. I, Metals, Minerals, and Fuels,* U. S. Department of the Interior, Bureau of Mines (US Government Printing Office, Washington, DC, 1975), p. 317.

12. *Final Environmental Impact Statement: Proposed Federal Coal Leasing Program*, pp. 1-39 and 1-40.

13. Ibid, p. 1-40.

14. Ibid, p. 1-85.

15. 30 United States Code (hereafter referred to as U.S.C.), §181 *et seq* (1970).

16. 43 Code of Federal Regulations (hereafter referred to as C.F.R.), Part 3500 *et seq* (1975).

17. *Final Environmental Impact Statement: Proposed Federal Coal Leasing Program,* Fig. 3-A, p. 1-B.

18. S. Rep. No. 94-296, 94th Congress, 1st Session 9 (1975). See generally, Council on Economic Priorities, *Leased and Lost* (1974) (hereafter cited as "CEP").

19. Ibid., Secretarial Order 2952. (See also Refs. 18, *supra*, and 21, *infra*.

20. Leases could be issued during this period if the following short-term criteria were met: that coal was needed immediately to maintain an existing mining operation or as a reserve for production in the near future and that the land to be mined was to be reclaimed in accordance with lease stipulations that provide for environmental protection and land reclamation and an environmental impact statement covering the proposed lease prepared when required under the National Environmental Policy Act.

21. See text accompanying Refs. 36-46, *infra*.

22. See text accompanying Refs. 47-63, *infra*.

23. Prospecting permits had a duration of 2 yr, but could be renewed for an additional 2 yr if needed and if certain showings were made. 30 U.S.C. §201(b) (1970). Holders of permits that matured during the moratorium will be allowed to acquire preference-rights leases as soon as a showing of coal in commercial quantities has been made and the requirements of NEPA satisfied. Solicitor's Opinion, Department of the Interior, in connection with the application of Utah Power and Light (October 16, 1974).

24. 30 U.S.C. §201(b) (1970).

25. Ibid., §201(a) (1970).

26. Most existing coal leases require royalties of \$0.15-\$0.25 per ton. The most recent coal leases require ad valorum royalties of 4% for underground coal and 6% for surface coal. The target royalty rate for new coal leases is 8% ad valorum at the point of shipment. In any event, the lease royalty will not be less than 5%, and in some instances may be as high as 10%. Rentals have traditionally been \$0.25 per acre for the first year of the lease, \$0.50 per acre for years 2, 3, 4, and 5, and \$1 per acre for lease year 6 and beyond. Leases recently issued under the short-term criteria have required \$1 per acre per year for the first 5 yr, and from \$3-\$4 per acre for subsequent years. Rental may be credited against royalty charges. Hearings on S. 319 before the Subcommittee on Minerals, Materials, and Fuels of the Senate Committee on Interior and Insular Affairs, 94th Congress, 1st Session 49 (1974), hereafter cited as Senate Coal Lease Hearings.

27. Advance payment of rental at a rate of \$1 per acre was commonly used in technical satisfaction of diligence requirements, however.

28. Twenty-five cents per acre for the first year, \$0.50 per acre for the second through fifth years, and \$1 per acre in following years. 30 U.S.C. §207 (1970).

29. *See* 30 C.F.R. §211 (1975).

30. *See* 43 C.F.R. §3041, concerning surface mining.

31. A single lease may not exceed 2560 acres. 30 U.S.C. §202 (1970).

32. Holdings are limited to 46 080 acres. 30 U.S.C. § 184 (a) (1) (1970).

33. Ibid., at 491-92.

34. The best opportunity to strengthen diligence requirements exists for leases signed on the form in use since January 1964. This form subjects the lessee to regulations "now or hereafter in force," which permits the government to define "diligent development" in regulations and apply it immediately to these leases. Prior to this form, the lessee was subject only to regulations "now in force." The January 1964 form provides for either continuous operation or payment of an advance royalty (until recently \$1 per acre); the Associate Solicitor feels there is a case, though a conjectural one, for refusing to accept the royalty in lieu of production. Ibid., at 491.

35. A somewhat weaker but still reasonable basis exists for strengthening diligence requirements of leases signed on forms in use between October 1956 and January 1964. The lessee is not subject to regulations "hereafter in force," but there is a clause requiring "reasonable diligence in operations," a term which is subject to interpretation. Ibid., at 492.

36. 40 Fed. Reg. 60070 (December 31, 1975) (proposed amendment of 43 C.F.R. Part 3500).

37. 41 Fed. Reg. 21779 (May 28, 1976).

38. *Logical Mining Unit* (LMU). A Logical Mining Unit, or LMU, is an area of coal land that can be developed and mined in an efficient, economical, and orderly manner, with due regard to the conservation of coal reserves and other resources. An LMU may consist of one or more federal leaseholds, and may include intervening of adjacent nonfederal lands, but all lands in an LMU must be under the effective control of a single operator and capable of being developed and operated as a unified mine. Every federal lease will automatically be considered by itself an LMU as of the effective date of the lease or (the effective date of these regulations), whichever is later. Any other LMU will become effective only upon its approval by the Mining Supervisor where it is requested by the lessee(s). The boundaries of an LMU may later be changed upon application by the lessee(s) and with the approval of the Mining Supervisor and after consultation with the authorized officer.

    Logical Mining Unit (LMU) Reserves. LMU Reserves are defined as being equal to the sum of (1) estimated recoverable reserves under federal lease in the LMU, and (2) estimated nonfederal recoverable reserves in the LMU that will be mined prior to the extraction of all estimated federal reserves in the LMU. The LMU reserves associated with a federal lease are the estimated LMU reserves as of the effective date of the approval of the LMU, of which that lease is a part, except that the estimate of LMU reserves under both (1) and (2) above may be adjusted by the Mining Supervisor whenever he approves a modification of the LMU boundaries or whenever significant new information becomes available about the amount of such reserves, including the time at which a mining plan is approved. 43 C.F.R. §3500.0-5(d)-(e).

39. 43 C.F.R. §3523.2-1(b)(1) is amended by the insertion of "(i)" after the word "Coal" and by adding the following paragraphs (b)(ii) and (iii), respectively:
    Any coal lease on which the lessee does not meet diligent development and either continuous operation or advance royalty requirements will be subject to cancellation in whole or in part. In deciding whether to cancel a lease under this paragraph (b)(ii), the Secretary will not consider adverse circumstances that arise out of normally foreseeable business risks, such as fluctuations in prices, sales, or costs, including foreseeable costs of compliance with requirements for environmental protection; commonly experienced delays in delivery of supplies or equipment; or inability to obtain sufficient sales. The requirements as to notice included in paragraph (b)(i) are applicable to cancellations under this paragraph also.

    Should a lease be canceled or relinquished for any reason, all rentals and royalties, including advance royalties already paid or due, will be forfeited to the United States. 43 C.F.R. §3523.2-1. The date of the lease would be used if it were later.

40. 43 C.F.R. §3500.0-5(f).

41. 43 C.F.R. §3500.0-5(f)(2).

42. 43 C.F.R. §3500.0-5(g). The annual average amount is to be computed on a 3-yr basis using the year in question and the 2 preceeding years.

43. 43 C.F.R. §3503.3-2(b)(1). This provision specifically states that "After the requirement for advance royalties has ceased, the lease shall be subject to the requirement of continuous operation." This language suggests that the option to pay advance royalty in lieu of production only exists for 40 yr. The terms of newly

enacted federal legislation appear to override this provision, and limit the option to pay advance royalty to 15 yr. See Ref. 51, *infra*.

44. *General*. The terms and conditions of coal, potassium, and phosphate leases are subject to readjustment at the end of each 20-yr period succeeding the effective date of the lease unless otherwise provided by law at the time of the expiration of such periods. Before the expiration of each 20-yr period, whenever feasible, the lessee will be notified of the proposed readjustment of terms or notified that no readjustment is to be made. Within 30 days after receipt of the notice, unless the lessee files his objection to the proposed readjusted terms, or the lessee files a relinquishment of the lease, he will be deemed to have agreed to such readjusted terms.

    Coal. All coal leases will be readjusted, if necessary, at the end of the next scheduled adjustment of terms and conditions under paragraph (a) above by the addition of provisions consistent with 43 C.F.R. §3503.3-2(b)(1) so that they require advance royalties. The percentages of reserves on which the advance royalty for the years following the readjustment of terms will be based (on) the same percentages as those appropriate for a lease dated (the effective date of these regulations). Lessees will be allowed to credit against the advance royalties due under that schedule any production royalties paid in lease years prior to the readjustment of terms, which production royalties are in excess of advance royalties that would have been due had advance royalties been in effect from June 1, 1976. 43 C.F.R. §3522.2-1.

45. B.N.A. ENVIRONMENT REPORTER, 6 *Current Dev*. 1707 (1976).

46. Final regulations on competitive leasing of federally owned coal appeared at 41 Fed. Reg. 22051 (June 1, 1976).

47. H. R. 6721. See H. R. Rep. No. 94-681, 94th Cong., 1st Sess. (1975).

48. S. 391.

49. *Cong. Quarterly*, Vol. 34, p. 2112 (August 7, 1976).

50. Ibid., §6, as amended; *Cong. Quarterly*, Vol. 34, p. 218 (Jan. 31, 1976).

51. Ibid., §6. Clearly, the new law supersedes conflicting elements of federal regulations, so this 15-yr limitation will govern. Its provisions with respect to submission of operating reclamation plans will also override departmental regulations. Compare 41 Fed. Reg. 20252 (May 17, 1976, [43 C.F.R. §3041; 30 C.F.R. §211] with §6 of the Act).

52. Ibid., §6.

53. Ibid. Coal mined by underground methods would be subject to a lower royalty rate, however.

54. Deferred bonus bidding whereby payment of the amount bid could be spread over the initial 10 yr of the lease would be utilized with respect to at least half of the acreage lease in any year. Ibid., §2.

55. Ibid., §6.

56. Ibid., §4.

57. Ibid., §11.

58. Ibid., §15.

59. Ibid., §3. The 15-yr period would not begin to run until the date of the amendments' enactment, however.

60. The bill also requires compliance with the Clean Air Act and Water Pollution Control Amendments and in addition specifies that no new lease can be undertaken until a comprehensive land use study has been completed. Ibid., §3.

61. H. R. Rep. No. 94-681, 94th Cong., 1st Sess. 15 (1975).

62. See references 34 and 35, *supra*. This reading appears to be consistent with the normal handling of a similar problem of oil and gas law; diligent development is regarded as a separate obligation from the requirement of production within a set period on pain of loss of the lease.

63. But see B.N.A. ENVIRONMENT REPORTER, 7 Current Dev. 573 (Aug. 6, 1976) where Interior Deputy Asst. Secretary Raymond A. Peck is quoted as saying that the "most dangerous impact" of the new amendments will be on the "due diligence" regulations adopted by the department on May 26. No explanation for this observation is provided.

64. 25 U.S.C. §396a (1970).

65. The rules applicable to allotted lands are very similar. See 25 C.F.R. Part 172.

66. A further provision, 25 U.S.C. §415 (1970 Supp.), states that "restricted Indian lands, whether tribally or individually owned, may be leased by the Indian owners, with the approval of the Secretary of the Interior, for public, religious, educational, recreational, residential, or business purposes, including the development or utilization of natural resources in connection with operations under such leases..." Lease terms of up to 99 yr are authorized for the Navajo reservation. *Id.* without a "business" operation on tribal lands, however, this provision would not appear to have controlling effect with respect to coal development.

67. 25 C.F.R. §171 (1975).

68. 25 C.F.R. §171.2 (1975). Prospecting permits are also available as an exploratory tool, but not as a device for achieving a preference-right lease. 25 C.F.R. 171.27a (1975).

69. 25 C.F.R. §171.9 (1975).

70. 25 C.F.R. §171.15(c).

71. 25 C.F.R. §171.14 (1975).

72. For example, in negotiation for its lease with the Hopis and Navajos in Arizona, Peabody agreed to hire a 75% Indian work force on the reservation, pay an average royalty of $0.25 per ton on coal produced, and dig new wells for the tribe to compensate for the lowering of the area's water table in connection with the mining. See Ref. 18, *supra*, at 32.

73. Personal communication from Richard Levin, UCLA law student who worked on the Navajo Reservation during summer 1974, and who has visited there recently, April 25, 1976.

74. For example, several years after the completion of lease arrangements, the Northern Cheyenne Tribal Council, recognizing the disadvantageous terms of leases which they had entered on the advice of the BIA, voted to direct the agency to withdraw the Department of the Interior's approval and terminate the existing leases. See Ref. 18, *supra*, at 35.

75. See Colorado Enabling Act §7, 18 Stat. 474 (March 3, 1875); New Mexico Enabling Act §6, 36 Stat. 557 (June 20, 1910); Utah Enabling Act §6, 28 Stat. 107 (July 16, 1894); Wyoming Enabling Act §4, 26 Stat. 222 (July 10, 1890).

76. COL. REV. STAT. §36-1-113 (Supp. 1976).

77. N. M. STAT. §7-10-2 (1953).

78. N. M. STAT. §7-10-3 (1953).

79. N. M. STAT. §7-10-2 (1953).

80. UTAH CODE ANN. §65-1-15 (1953).

81. UTAH CODE ANN. §65-1-18 (1953).

82. WYO. STAT. §36-74(a) (Supp. 1975).

83. WYO. STAT. §36-74(c) (Supp. 1975).

84. See 43 C.F.R. 3041 (1975); see also 30 C.F.R. §211 (1975).

85. See 40 Fed. Reg. 41122 (Sept. 5, 1975); Final Environmental Impact Statement—Surface Management of Federal Coal Resources (43 C.F.R. 3041) and Coal Mining Operations (30 C.F.R. 211) (hereafter cited as Surf. Man. EIS).

86. 41 Fed. Reg. 20252 (May 17, 1976) (43 C.F.R. 3041, 30 C.F.R. 211); See also B.N.A. ENVIRONMENT REPORTER, 7 Current Dev. 27 (May 14, 1976).

87. In March 1975, the House of Representatives passed the strip mining bill 333 to 86, while the Senate voted to support the measure by an 84 to 13 margin. The House failed to override President Ford's May 20 veto 278 to 143; a change of three votes would have given the two-thirds majority needed.

88. See H. R. Rep. 94-896, 94th Cong., 2nd Sess. (1976).

89. Ibid., §506.

90. Ibid., §510.

91. Ibid., §510.

92. A reclamation fee of $0.15 per ton would also be levied on coal produced by underground methods. The procedure for calculating the fee on lignite varies slightly. Ibid., §401.

93. Ibid., §401.

94. Ibid., §513.

95. Ibid., §509.

96. Ibid., §503.

97. See, e.g., Clean Air Act of 1967, Pub. L. No. 90-148, 81 Stat. 485 (1967) was amended by Clean Air Act 107, 42 U.S.C.A. 1857c-2 (1976). Federal Water Pollution Control Act, 33 U.S.C.A. 1251 *et. seq.* (1976).

98. See Hearing on the President's Veto of H. R. 25 Before the Subcommittee on Energy and the Environment and Subcommittee on Mines and Mining of the House Committee on Interior and Insular Affairs, 94th Cong., 1st Sess. (1975).

99. "(b) No permit...shall be approved unless the applicant affirmatively demonstrates and the Secretary finds...that....

(5) the proposed surface coal mining operation, if located west of the one hundredth meridian west longitude, would not have a substantial adverse effect on alluvial valley floors underlain by unconsolidated stream laid deposits where farming can be practiced in the form of flood crop lands, excluding undeveloped range lands, where such valley floors are significant to the practice of farming or ranching operations, including potential farming or ranching operations if such operations are significant and economically feasible." S. 391, §207(b)(5).

100. See discussion of federal water quality requirements located elsewhere in the legal subproject's report, Chap. 6.4 of "Study of Alternative Locations."

101. Personal communication with Tim Vollman, Office of the Solicitor to the Department of the Interior, April 27, 1976.

102. 40 Fed. Reg. 41122 (Sept. 5, 1975). Existing regulations are codified at 25 C.F.R. Part 177. They require the Bureau of Indian Affairs to complete a technical examination of lease sites to determine potential environmental effects of mining before the issuance of leases and provide that the US Geological Survey is to approve exploration and mining plans before operations begin and inspect the mining sites periodically thereafter. The operator is also required to post a performance bond. The need for more effective regulation is widely recognized. See Ref. 18, CEP, *supra*, at 34. Note: *Strip mining on Reservation Lands: Protecting the Environment and the Rights of Indian Allotment Owners,* 35, MONT. L. REV. 209 (1974).

103. The surface mining regulations of the Navajo Tribe are available from the Navajo Tribal Council, Window Rock, Arizona.

104. See Comment, *Land Quality: The Regulation of Surface Mining in Wyoming*, 9 LAND & WATER L. REV. 99 (1974).

105. Surf. Man. EIS, Ref. 85, *supra,* at I-36; proposed regulations [40 Fed. Reg. 41122 (Sept. 5, 1975)] at 43 C.F.R. 3041.8.

106. COLO. REV. STAT. §§34-32-101 to 34-32-118 (1973).

107. COLO. REV. STAT. §34-32-105 (1973). Other duties of the Board include the initiation and encouragement of studies to advance the state of land reclamation technology and coordination of the provisions of the Act with related programs of other state agencies. COLO. REV. STAT. §34-32-107.

108. COLO. REV. STAT. §34-32-109 (1973). Failure to obtain a permit before engaging in strip mining activities is a misdemeanor punishable by a fine of $50-$1000, with each day of operation constituting a separate violation.

109. COLO. REV. STAT. §34-23-330(1) (1973).

110. COLO. REV. STAT. §34-32-110(2) (1973).

111. $50 plus $15 for each acre or fraction of an acre to be affected by the operation. COLO. REV. STAT. §34-32-110(4) (1973).

112. Alternatively, cash and securities in the amount of the bond may be deposited with the Board. COLO. REV. STAT. §34-32-113(1) (1973).

113. COLO. REV. STAT. §34-32-112(1) (1973).

114. COLO. REV. STAT. §34-32-110(5) (1973).

115. COLO. REV. STAT. §34-32-109 (1975); *cf.* COLO. REV. STAT. §34-1-304.

116. COLO. REV. STAT. §34-32-111(1)(a) (1973).

117. COLO. REV. STAT. §34-32-111(g), (h),(i),(j),(k) (1973).

118. COLO. REV. STAT. §34-32-111(1) (1973). Subject to Board approval the operator may choose the type of reclamation project he wishes to undertake, but he must then conform to statutory requirements for that type of reclamation. COLO. REV. STAT. §34-32-111(1)(a) (1973). Forest, range, crop, horticultural, homesite, recreational, industrial, plus food, shelter, and ground cover for wildlife are all uses mentioned as possible land reclamation goals. COLO. REV. STAT. §34-32-111(f) (1973).

119. COLO. REV. STAT. §34-32-111(f) (1973).

120. COLO. REV. STAT. §34-32-111(m) (1973).

121. There are two exceptions. First, planting required under a reclamation plan is waived in the cases of active refuse dumps, active haulage roads or cuts, sites proposed for future mining, and areas where permanent pools or lakes have formed. Second, planting requirements are waived in areas where the soil is toxic or barren to an extent not feasibly remediable by measures like fertilization or replacement of overburden. COLO. REV. STAT. §34-32-111 (m)(I) & (II) (1973).

122. COLO. REV. STAT. §34-32-111(6) (1973). The basic fee for an amendment increasing the amount of the affected acreage is $10 plus $15 per acre or fraction of an acre of increase.

123. Ibid. When the Board determines that an operator has violated the provisions of the Act, it must "endeavor to remedy such violation" by "private conference, conciliation, and persuasion." COLO. REV. STAT. §34-32-113(1) (1973). When such measures fail the Board may issue a formal complaint and require the operator to answer the charges at a hearing within 30 days. Witnesses may be subpoenaed at the operator's request. After the hearing the Board enters whatever order it deems appropriate and mails a copy of the order to the operator. *Id.* If the order is not complied with

within the time specified, the Board may request that the Colorado Attorney General initiate a proceeding to have the bond of the operator forfeited. *Id.* The Attorney General must first notify the operator of the violation and provide a hearing within 30 days. After the hearing, the Board either withdraws the notice of violation or renews its request for initiation of a forfeiture proceeding, which is then undertaken by the Attorney General's Office. *Id.* No new permit can be issued to any operator who is conducting mine operations in violation of the provisions of the Act. COLO. REV. STAT. §34-32-115 (1973).

124. COLO. REV. STAT. §34-32-117(2) (1973).

125. N.M. STAT. ANN. §§63-34-1 to 63-34-20 (1974).

126. This narrow application may render the Act vulnerable to attack on federal equal protection grounds. In 1947 the Illinois Supreme Court held that strip mining land reclamation regulations imposed exclusively on coal operations constitute an unreasonable discrimination in favor of clay, stone, gravel, and sand mining activities. North Illinois Corp. vs Medill, 397 Ill. 98, 72 N.E. 2d 844.

127. N.M. STAT. ANN. §64-34-8 (1974).

128. The officials are the Directors of the Bureau of Mines, the Department of Game and Fish, the Environmental Improvement Agency, and the Agriculture Experimental Station of New Mexico State University, plus the State Engineer, the Chairman of the Soil and Water Conservation Committee, and the Commissioner of Public Lands. N.M. STAT. ANN. §63-34-3 (1974). The Director of the Bureau of Mines and Mineral Resources executes and administers the Commission's regulations. N.M. STAT. ANN. §63-34-5 (1974). It is the duty of the Commission to conduct research on strip mining in New Mexico and to administer the Act. N.M. STAT. ANN. §63-34-4 (1974).

129. N.M. STAT. ANN. §63-34-6 (1974).

130. N.M. STAT. ANN. §63-34-7 (1974). The application fee is $50, the acreage fee is $10 per acre expected to be mined in the first year of operations.

131. N.M. STAT. ANN. §63-34-9 (1974).

132. N.M. STAT. ANN. §63-34-7(B) (1974).

133. N.M. STAT. ANN. §63-34-6 (1974).

134. N.M. STAT. ANN. §63-34-9(B) (1974).

135. N.M. STAT. ANN. §63-34-9(D) (1974).

136. N.M. STAT. ANN. §63-34-9(C) (1974).

137. N.M. STAT. ANN. §63-34-18 (1974).

138. An annual acreage fee not to exceed $20 per acre mined may be established by the Commission for active strip mining operations. N.M. STAT. ANN. §63-34-7(C) (1974).

139. N.M. STAT. ANN. §63-34-16 (1974).

140. N.M. STAT. ANN. §63-34-13 (1974).

141. N.M. STAT. ANN. §63-34-15 (1974).

142. N.M. STAT. ANN. §63-34-10 (1974).

143. N.M. STAT. ANN. §63-34-10(D) (1974).

144. N.M. STAT. ANN. §63-34-11 (1974).

145. N.M. STAT. ANN. §63-34-5(c), 63-34-12 (1974). When an operator violates the Act or any regulation established under its authority, the Director must notify him of the noncompliance. If the deficiency is not remedied within 30 days of the notice, the Commission may conduct a hearing on the issue and suspend or revoke the operator's permit if the facts warrant such a step. N.M. STAT. ANN. §63-34-17 (1974). In addition, civil penalties not to exceed $1000 per day of violation may be imposed. N.M. STAT. ANN. §63-34-19 (1974). If, in the case of a violation, the Commission is unable to obtain voluntary compliance within a reasonable time, it may file an injunctive action in the state district court of the county in which the mine is located. N.M.. STAT. ANN. §63-34-12(C) (1974).

146. N.M. STAT. ANN. §63-34-12(C) (1974).

147. UTAH CODE ANN. §40-8-3 (Supp. 1975). Incorporated into the Act is a legislative finding that mining is essential to Utah and the nation and necessarily involves some alteration of "the surface of the earth," but that alterations should be kept to a minimum and mined land should be reclaimed UTAH CODE ANN. §40-8-2 (Supp. 1975). The scope of the regulation scheme created by the Act extends beyond overt strip mining operations to include "surface effects of underground mining operations as well." UTAH CODE ANN. §40-8-4(b) (Supp. 1975).

148. UTAH CODE ANN. §40-8-6 (Supp. 1975).

149. UTAH CODE ANN. §40-8-5(2) (Supp. 1975).

150. UTAH CODE ANN. §40-8-13(1) (Supp. 1975). Notices must also be filed by mining operations already active on the effective date of the Act. UTAH CODE ANN. §40-8-23 (1953).

151. UTAH CODE ANN. §40-8-7(1). (Supp. 1975). Although no filing fee is specified in the statutes, the Board is expressly authorized to set one. UTAH CODE ANN. §40-8-23 (Supp. 1975).

152. UTAH CODE ANN. §40-8-13(4) (Supp. 1975).

153. UTAH CODE ANN. §40-8-16(3) (Supp. 1975).

154. UTAH CODE ANN. §40-8-16(1) (Supp. 1975).

155. UTAH CODE ANN. §40-8-16(2)(a) (Supp. 1975).

156. UTAH CODE ANN. §40-8-16(2)(b) (Supp. 1975).

157. UTAH CODE ANN. §40-8-16(2)(c) (Supp. 1975).

158. UTAH CODE ANN. §40-8-14(1) (Supp. 1975).

159. UTAH CODE ANN. §40-8-14(3) (Supp. 1975).

160. UTAH CODE ANN. §40-8-14(3) (Supp. 1975).

161. UTAH CODE ANN. §40-8-14 (Supp. 1975).

162. UTAH CODE ANN. §40-8-14(4) (Supp. 1975).

163. UTAH CODE ANN. §40-8-15 (Supp. 1975).

164. In case of a temporary suspension of mining operations, excluding labor disputes, expected to be in excess of 6 months, but not less than 2 years' duration, the operator shall, within 30 days, notify the division. UTAH CODE ANN. §40-8-21(1) (Supp. 1975).

165. A notice of intention to revise mining operations may be submitted at any time to allow for "changing conditions and developing technology." Such a notice is handled the same as a notice of intention to mine, under rules to be promulgated by the Board. UTAH CODE ANN. §40-8-18 (Supp. 1975).

166. UTAH CODE ANN. §40-88-4(7) (Supp. 1975).

167. UTAH CODE ANN. §40-8-12(1)(a) (Supp. 1975).

168. UTAH CODE ANN. §40-8-12(1)(b) (Supp. 1975).

169. UTAH CODE ANN. §40-8-12(1)(c) (Supp. 1975).

170. UTAH CODE ANN. §40-8-12(4) (Supp. 1975).

171. UTAH CODE ANN. §40-8-14(b) (Supp. 1975).

172. UTAH CODE ANN. §40-8-9(2) (Supp. 1975).

173. Wyo. Laws, ch. 250, 1 *et seq.*, effective July 1, 1973. WYO. STAT. §§35-502.1 *et seq.* (Cum. Supp. 1975).

174. See WYO. STAT. §35-502.2 (Cum. Supp. 1975).

175. WYO. STAT. §35-502.20-.24 (Cum. Supp. 1975).

176. See WYO. STAT. §35-502.21 (Cum. Supp. 1975).

177. The definition of "highest prior use" is to be set by rules and regulations of the Environmental Quality Council. WYO. STAT. §35-502.12(a)(i) (Cum. Supp. 1975).

178. WYO. STAT. §35-502.4-502.7 (Cum. Supp. 1975).

179. The Council is a five-member advisory board comprising two members from the public, one from industry, one from agriculture, and one representing political subdivisions. WYO. STAT. §35-502.11-502.12 (Cum. Supp. 1975).

180. WYO. STAT. §35-502.12 (Cum. Supp. 1975).

181. WYO. STAT. §§35-502.10 & 502.22 (Cum. Supp. 1975).

182. WYO. STAT. §35-502.12(a)(iii) (Cum. Supp. 1975).

183. WYO. STAT. §35-502.21 (Cum. Supp. 1975); *cf.* WYO. STAT. §35-502.20(e) (Cum. Supp. 1975).

184. WYO. STAT. §35-502.20 (Cum. Supp. 1975).

185. See Kleppe vs New Mexico, 44 U.S.L.W. 4878 (June 15, 1976); The Applicability of State Conservation and Other Laws to Indian and Public Lands, 16 ROCKY MTN. MIN. L. INST. 347, 349 (1971).

186. See Comment, *Land Quality: The Regulation of Surface Mining Reclamation in Wyoming,* 9 LAND & WATER L. REV. 97, 112 (1974).

187. Kleppe vs New Mexico, 44 U.S.L.W. 4878 (June 15, 1976); Utah Power & Light Co. vs United States, 243 U.S. 389 (1917); see also Olsen, *Surface Reclamation Regulations on Federal and Indian Mineral Leases and Permits,* 17 ROCKY MTN. MIN. L. INST. 149, 160 (1972).

188. WYO. STAT. §35-502.24(b) (Cum. Supp. 1975).

189. WYO. STAT. §9-276.19 (Cum. Supp. 1975).

190. WYO. STAT. §35-502.34 (Cum. Supp. 1975).

191. WYO. STAT. §35-502.34 (Cum. Supp. 1975).

192. WYO. STAT. §35-502.34(c)(i) (Cum. Supp 1975).

193. WYO. STAT. §35-502.34(e)(xvi) (Cum. Supp. 1975).

194. WYO. STAT. §35-502.34(c)(i) (Cum. Supp. 1975).

195. H. H. Doelling, "Alton Coal Field," in H. H. Doelling and R. L. Graham, "Southwestern Utah Coal Fields," *Utah Geological and Mineralogical Survey Monograph Series No. 1,* 1-66, p. 1 (1972).

196. H. H. Doelling and R. L. Graham, "Kaiparowits Plateau Coal Field," in H. H. Doelling and R. L. Graham, "Southwestern Utah Coal Fields," *Utah Geological and Mineralogical Survey Monograph Series No. 1,* 67-249, p. 67 (1972).

197. Wesley H. Pierce, "Arizona," in Mining Informational Services, *1974 Keystone Coal Industry Manual* (McGraw-Hill Mining Publications, New York, 1974), 468-469, p. 468.

198. E. H. McGavock, and Gary W. Levings, "Ground Water in the Navajo Sandstone in the Black Mesa Area, Arizona," in *Geology of Northern Arizona,* Thor N. V. Karlstrom, Gordon A. Swann, and Raymond L. Eastwood, Eds. (Flagstaff: Geological Society of America, Rocky Mountain Section, 1973), 757-767, p. 759.

199. Refs. 195, p. 2, and 196, p. 92.

200. Ref. 197, p. 469.

201. Charles Kolstad, Los Alamos Scientific Laboratory, personal communication, July 1976.

202. Ref. 195, p. 6. Some question still exists as to where the boundary between the Dakota Sandstone and the overlying Tropic Shale should be drawn, and thus to which formation the upper coal zone belongs.

203. Ref. 195, p. 18.

204. Ref. 195, p. 15.

205. Ref. 196, pp. 78-79.

206. Ref. 196, p. 105.

207. Ref. 196, pp. 152-153.

208. Ref. 196, p. 83.

209. Ref. 196, p. 93.

210. "Energy Data System, Steam Electric Plant Consumption of Coal by Origin (From EPC 423) for 1975" (Computer Printout), p. 4, Los Alamos Scientific Laboratory, personal communication, 1976.

211. Much of it, being privileged information of the company on whose lease it was drilled, is available only to the USGS geologist mapping in the region.

212. Ref. 195, p. 20.

213. D. Carey, J. Wegner, O. Anderson, G. Weatherford, and P. Perkins, "Kaiparowits Handbook: Coal Resources," in *Lake Powell Research Project Interim Report* (Los Angeles: Institute of Geophysics and Planetary Physics, University of California, 1975), pp. 44-47.

214. Ref. 196, p. 106.

215. Hearing on H. R. 3265 before the Subcommittee on Mines and Mining, of the Committee on Interior and Insular Affairs, 94th Congress, 1st Session, March 14, 1975, pp. 107-111.

216. Ref. 196. p. 92.

217. Ref. 215, *supra*, pp. 108 and 111.

218. "Power Firms Mull New Use for Controversial Utah Site," San Diego Evening Tribune (July 16, 1976).

219. H. H. Doelling, "Coal in Utah—1970," in H. H. Doelling, "Central Utah Coal Fields," *Utah Geological and Mineralogical Survey Monograph Series No. 3,* 543-560, p. 548 (1972).

220. H. H. Doelling, "Wasatch Plateau Coal Field," in H. H. Doelling, "Central Utah Coal Fields," *Utah Geological and Mineralogical Survey Monograph Series No. 3,* 58-243, p. 59 (1972).

221. H. H. Doelling, "Book Cliffs Coal Field," in H. H. Doelling, "Central Utah Coal Fields," *Utah Geological and Mineralogical Survey Monograph Series No. 3,* 244-415, p. 325 (1972).

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223. Ref. 220, p. 74.

224. Ref. 220, p. 126.

225. Ref. 220, pp. 74-75.

226. H. H. Doelling, "Emery Coal Field," in H. H. Doelling, "Central Utah Coal Fields," *Utah Geological and Mineralogical Survey Monograph Series No. 3,* 416-496, pp. 420 and 422 (1972).

227. Ibid., pp. 428 and 429.

228. Ibid., p. 438.

229. Ref. 219, pp. 555 and 556.

230. Ref. 226, p. 433.

231. Ref. 221, p. 379.

232. Ref. 221, p. 269.

233. Ref. 220, p. 80.

234. Ref. 220, p. 129.

235. Ref. 226, p. 443.

236. Ref. 221, p. 327, and Ref. 234.

237. Charles Kolstad, Los Alamos Scientific Laboratory, personal communication, March 1976.

238. Wasatch Plateau coal delivered to the Huntington Powerplant costs $10.18 per ton (41.73¢/mmBtu) in 1975. Ref. 210, p. 77, Dollars per ton ($/ton) is converted to cents per million Btu (¢/mmBtu) by multiplying by 100 000 and dividing by twice the heat content in Btu per pound.

239. Ref. 221, p. 273, Ref. 229, and Ref. 220, p. 91.

240. Helmut Doelling, Utah Geological and Mineral Survey, Salt Lake City, Utah, personal communication, July 1976.

241. Frank E. Kottlowski, Edward C. Beaumont, and John W. Shomaker, "New Mexico," in Mining Information Services, *1974 Keystone Coal Industry Manual* (McGraw-Hill Mining Publications, New York, 1974), 522-529, p. 522.

242. John W. Shomaker, Edward C. Beaumont, and Frank E. Kottlowski, "Strippable Low-Sulfur Coal Resources of the San Juan Basin in New Mexico and Colorado," New Mexico Bureau of Mines and Mineral Resources Memoir 25, p. 31 (1972).

243. Ibid., p. 117.

244. Frank E. Kottlowski and Edward C. Beaumont, "Coal," in "Mineral and Water Resources of New Mexico," New Mexico Bureau of Mines and Mineral Resources Bulletin 87, 100-116, p. 105 (1965).

245. Ref. 242, p. 39.

246. Ref. 242, p. 6.

247. Ref. 241, p. 525.

248. Ref. 242, p. 15.

249. Ref. 242, p. 43.

250. Ref. 241, p. 119.

251. Ref. 242, p. 71.

252. Ref. 242, p. 69.

253. Ref. 242, p. 121.

254. Draft, Southwest Energy Study Appendix K: Mining, photocopy, U.S. Bureau of Mines, p. 20 (1972).

255. Ref. 209, p. 52. New Mexico shipped 340 100 short tons of coal to the Cholla Powerplant in Arizona at a price of $9.085 per ton or 45.44¢/mmBtu (cents per million Btu).

256. Ref. 15, *supra*, pp. 88-91.

257. Randall Reyff, of the Atchison, Topeka, and Santa Fe Railway Company, Chicago, Illinois, personal communication, April 26, 1976.

258. "1975 Annual Report," Santa Fe Industries, Inc., p. 14.

259. A. L. Hornbaker, Richard D. Holt, and D. Keith Murray, "Colorado," in Mining Information Services, *1974 Keystone Coal Industry Manual* (McGraw-Hill Mining Publications, New York, 1974), 471-483, p. 475.

260. H. H. Doelling, "Sego Coal Field," in "Eastern and Northern Utah Coal Fields," *Utah Geological and Mineralogical Survey Monograph Series No. 2,* 191-267, p. 191 (1972).

261. David. C. Jones and D. Keith Murray, "Coal Mines of Colorado Statistical Data," *Colorado Geological Survey Information Series 2,* p. 12 (1976).

262. Ibid., p. 13.

263. Ref. 260, p. 207.

264. Ref. 259, pp. 474-475.

265. Ref. 259, pp. 475-476.

266. Ref. 260, p. 236.

267. Ref. 259, p. 472.

268. Ref. 219, p. 554.

269. E. R. Landis, "Coal Resources of Colorado," US Geological Survey Bulletin 1072-C:131-232, pp. 135-136 (1959).

270. Ref. 260, p. 211.

271. Ref. 210, p. 6.

272. *Coal 1975*, Colorado Division of Mines, p. 5 (1976).

273. Ibid., p. 6.

274. Ref. 259, pp. 475-477.

275. Ref. 269, p. 143.

276. Ref. 261, pp. 8-24.

277. Ref. 259, p. 477.

278. Ref. 259, p. 476.

279. Ref. 259, pp. 478-479.

280. Ref. 210, p. 6.

281. Ref. 215, *supra*, pp. 56-69.

282. Ref. 272, p. 16.

283. "Annual Report, Year Ending December 31, 1975," Wyoming State Inspector of Mines, p. 34 (1976).

284. Ibid., pp. 30-32.

285. Gary B. Glass, *Review of Wyoming Coalfields, 1975* (Laramie: Geological Survey of Wyoming, 1975), p. 15.

286. Ibid., p. 14.

287. Ibid., p. 11.

288. Ibid., p. 12.

289. Ref. 210, pp. 96-100.

290. Gary B. Glass, "State-Owned Coal Lands in Wyoming," *Public Information Series 2* (Laramie: Geological Survey of Wyoming, 1976), p. 2.

291. *Wyoming Mineral Yearbook 1975,* Wyoming State Department of Economic Planning and Development, p. 8 (1976).

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APPENDIX A2

COAL MINING OPERATIONS AND FACILITIES[1]

The steps necessary to supply coal for a coal-fired power plant consist of exploration, development, production, benefication, and restoration.

A2.1. Exploration

Exploration is conducted to locate and delineate the size, shape, and grade of an economic coal deposit. Preliminary or prospecting exploration determines the presence of a coal deposit through searches of the geologic literature and field reconnaissance. Previous discoveries, access routes, and surface and mineral ownership are also determined. Final exploration begins with the drilling of exploratory holes at locations determined during the geologic field reconnaissance. Detailed geology and drill-hole data give information on the nature of the overlying strata, depth and thickness of the coal deposit, and the quantity of ground water. Samples obtained from drill holes or test pits are analyzed to establish the grade and quality of the coal.

A2.2. Development

Development of a coal deposit begins long before production starts and continues throughout the life of the mine. Development during mining consists mainly of extending haul roads, power lines, and opening new roads to the working places.

A2.2.1. Planning. Planning is the first stage of development and must include all details of the work: mining maps, facilities, and environmental protection steps. Detailed development drilling is done at this stage to define mine limits and mining problems.

A2.2.2. Construction of Facilities. Construction of access roads, utility lines, a mine plant, and often a railroad spur compose the second phase of coal mine development. The mine plant is usually constructed near the main portal for underground mines and close enough to surface workings to minimize

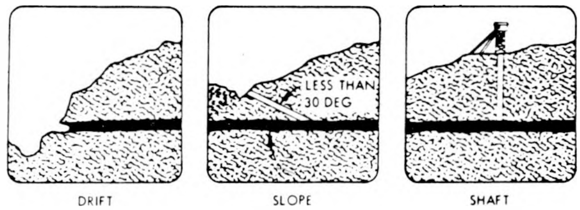

Fig. A2-1.
The three types of access used in underground coal mines.

coal haulage. The mine plant usually consists of a tipple, coal storage facilities, power substation, and waste disposal areas, along with offices, a laboratory, change houses, and storage buildings. Mine ventilation fans are stored here for underground mines.

A2.2.3. Mine Access. Access to underground coal deposits is through drifts, slopes, or shafts (Figure A2-1). Main entries are extensions of the main access portals and are the major routes of underground transport for the life of the mine. A minimum of three entries must be made—one for air intake, one for coal removal, and one for air exhaust. Men and equipment usually enter through the air intake entry.

Panel entries are driven from the main entries creating blocks of mineable coal up to 1 mile by 1/2 mile. These entries serve as routes to working places and air circulation conduits. To ensure that both entries remain open while needed, they must be supported by roof bolts, roof trusses, yieldable arches, and reinforced concrete liners or wood or steel sets.

A2.2.4. Mine Transportation and Excavation Equipment. The coal mine transportation system, whether conveyor or railroad, must be installed, and the installations of water, air, and communication systems in the mine are also development phases. In surface operations, the large excavation equipment, such as bucket-wheel excavators, draglines, and shovels, must be assembled. Initial overburden removal is also part of development.

A2.3. Production

Coal is produced from mines by a number of different methods. The method chosen depends upon the depth of overburden and the geologic conditions of the coal seam and surrounding rock. It is also chosen to minimize possible environmental damage from air and water pollution and land subsidence, to maximize worker health and safety (underground coal mining is still this nation's most hazardous industry), and to maximize coal resource recoverability. Production techniques can be separated into two basic categories: (1) underground mining and (2) surface mining.

A2.3.1. Underground Mining. Three methods most commonly used to mine coal underground in the United States are room-and-pillar, longwall, and shortwall. All methods, however, result in varying degrees of surface subsidence depending generally on the thickness and nature of overburden and the amount of coal left for support.

Room-and-Pillar Mining. Room-and-pillar mining has been in use longer in the United States than any other method. Mining advances from the panel entries into the coal panels, creating rooms whose roofs are supported by pillars of coal left in place. After the block, section, or panel has been mined, portions of the supporting pillars are removed as mining retreats toward the main entry. Conventional room-and-pillar mining requires that a number of working entries be driven into the panel so that each operational phase (undercutting, drilling, loading the charge, blasting, loading the shot coal, and roof bolting) can be done simultaneously without interfering with the other operations (Fig. A2-2). Continuous mining by room-and-pillar methods has recently been replacing conventional mining. Electric-powered machines rip, bore, or dig coal away from the working face and either load it into a shuttle car or pile it behind. Continuous miners still must stop for roof bolting and the advancement of support equipment.

If the entire thickness of the coal seam is removed, room-and-pillar mining can recover over 50% of the in-place coal. In seams over 10 feet thick, or where coal must be left on the roof because of irregularities or for support, recoverability will be less. The greater the amount of recovered coal, the greater the surface subsidence, but also the more uniform that subsidence will be.

Longwall Mining. Longwall mining long has been in use in Europe but has only been used in the

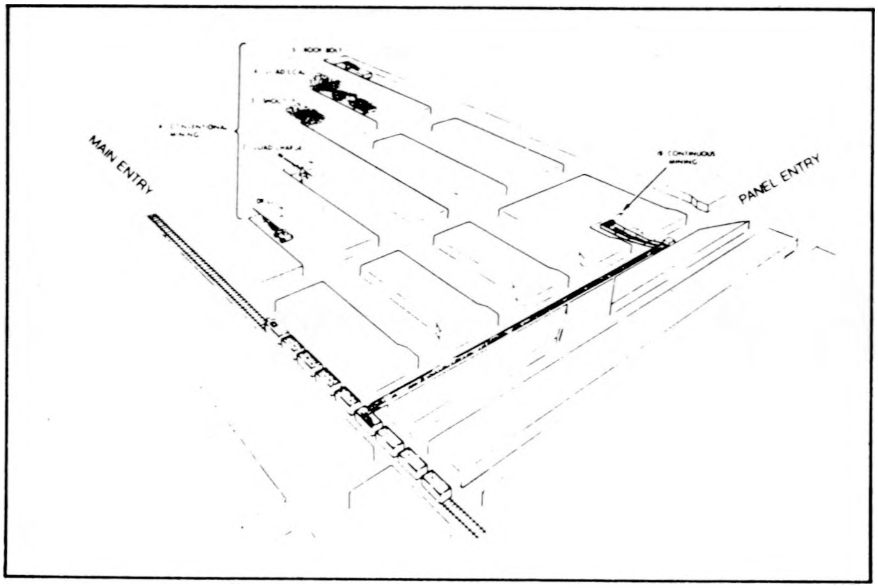

Fig. A2-2.
Room-and-pillar mining techniques.

United States in the last 25 yr. It is used most efficiently in seams of medium height (42 to 60 in.). Longwall blocks or panels are generally from 300 to 600 ft wide and up to 1-1/2 miles long. The longwall mining machine laterally shears or plows the coal from the entire face of the panel as it moves back and forth across the panel width, advancing forward after each pass (Fig. A2-3). A conveyor removes the excavated coal to secondary haulage conveyors in either flanking main entry while self-advancing hydraulic jacks support the roof that is allowed to collapse behind the work area. Surface subsidence is uniform in general over the excavated panel and occurs as the mining progresses.

Shortwall Mining. Shortwall mining is a relatively new variation of the basic longwall method but cuts in blocks only 100 to 500 ft wide and 300 to 500 ft long. The coal is cut by continuous miners and loaded into shuttle cars. Surface subsidence is usually irregular with depressions over the panels occurring as mining advances.

A2.3.2. Surface Mining. Strip, auger, open-pit, and quarry-type mining are the four surface mining methods now planned or in use; the first two are the most prevalent. Reclamation of the disturbed surface now plays a part in determining the operational methods used in surface mining.

Strip Mining. Strip mining can be accomplished either by area stripping or contour stripping. In area strip mining, the overburden is removed from narrow, parallel bands and the exposed coal is removed (Fig. A2-4). The overburden from each successive band is placed in the preceding cut after the coal has been removed. In the United States, the most favored overburden removal tools are draglines and shovels, although bucket-wheel excavators are used extensively in Europe. Draglines operate atop the cut while shovels rest on the exposed coal. Bucket capacities average about 50 cubic yards but some now exceed 200 cubic yards. The exposed coal is then drilled and blasted and loaded into coal haulers by shovels or front-end loaders.

Contour stripping is most common in the steep terrain of Appalachia. Overburden is removed from the coalbed at the outcrop and mining proceeds around the hillside. The overburden is cast down the hillslope or stacked along the outer edge of the cut. After the coal is removed, up to three more cuts are made into the hillside until the overburden becomes too great. This often results in a high wall of up to 100 ft and a high ridge of spoil on the outer side, both of which are subject to sliding and rapid erosion. Newer techniques have been developed to reduce erosion and sliding problems. The equipment most commonly used for contour stripping are dozers and front-end loaders, both much smaller in size than those used in area-stripping operations.

Auger Mining. Auger mining usually recovers coal from areas where normal contour strip mining might be uneconomical and underground mining impractical. It entails first the construction of a bench wide enough to accommodate the auger around the hill. Then horizontal holes are bored into the exposed coal seam using augers that can remove coal up to 90 in. in diam and 200 ft in depth. Coal is then loaded and removed and the holes sealed and the site graded for reclamation.

Open-Pit Mining. Open-pit mining entails the removal of the overburden from the coal seams for the entire period of mining. This technique is being tried in areas where numerous pitching seams lie parallel to each other and crop out on a relatively flat terrain. The overburden is removed by scrapers or shovels and placed into trucks.

Quarry-Type Mining. Quarry-type mining is a variation of strip mining that benches thick seams to

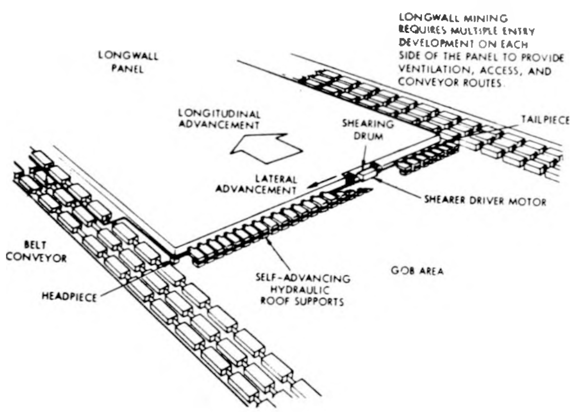

Fig. A2-3.
Longwall mining.

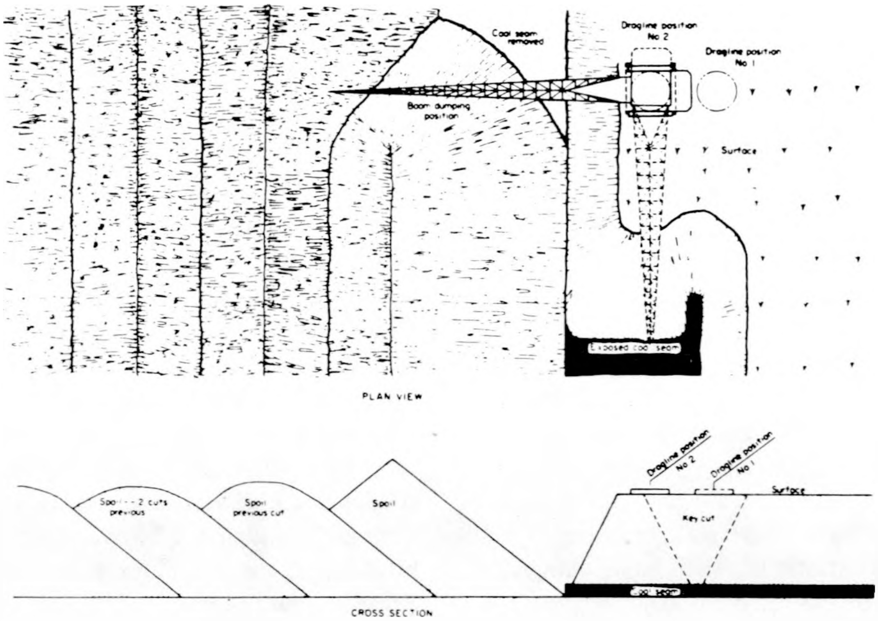

Fig. A2-4.
Cross section and plan view of a strip coal mine.

facilitate removal. It is a significant variation in that it does not disturb areas that are not mined. The spoil can be graded to a rolling topography or the last cut can remain as a lake.

A2.4. Benefication

Benefication is the preparation of mine-run coal for transportation to market. In its simplest form, this consists only of crushing and sizing. Many coals, however, contain impurities that must be removed before shipping the coal. These impurities include rock, clay, shale, and pyrite, and can be from 0 to 25% of the total raw coal processed. Crushing and screening, done with a breaker, often remove the largest of these, but further processing is usually required. This is commonly called washing and can be either dry or wet.

A2.4.1. Dry Washing (Air Washing). Pulsating air is used to wash coals that are easily cleaned and can essentially eliminate the need for close screen sizing. Air washing also eliminates problems of water pollution as well as air pollution by having plants completely enclosed. It is most acceptable to coal producers in that it adds no additional moisture to the coal which would decrease the delivered coal's heat content per pound.

A2.4.2. Wet Washing. Wet washing of coal works by floating the coal in a water bath (made denser by the addition of other solids or salts or having upward moving currents) through which the denser impurities sink. After initial breaking and screening, wet washing may use jigs, screens, launderers, heavy medium cyclones, tricone separators, concentrating tables, froth flotation cells, filters, and/or driers to achieve the desired final product. Air and water pollution are usually not major problems since modern plants generally operate on closed cylces.

A2.5. Restoration

Site rehabilitation encompasses all three types of sites—underground, surface, and preparation plant sites. Often in the past no restoration was attempted after production ceased, other than to remove any valuable equipment. Now federal and state laws have been or are being enacted to require that at least minimal restoration work be completed (see Sec. 2.4). Often these include not only laws designed to protect air, water, and land quality, but also to require rehabilitation of all disturbed surface lands, filling of subsidence holes, permanently sealing all underground openings, removal of all surface structures, and rehabilitation of all refuse piles.

REFERENCE NOTE

1. Extensively excerpted from ***Final Environmental Impact Statement: Proposed Federal Coal Leasing Program***, US Department of Interior, Bureau of Land Management (US Government Printing Office, Washington, DC, 1975), pp. 1-45 to 1-62.

APPENDIX B2

PRELIMINARY COALFIELD ANALYSIS

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Heat (Btu/lb)	Quality Sulfur (%)	Ash (%)	Mineability and Development
Stone Canyon Field, California[1]	200	<30?	---	12 447	4.17	6.23	Very steep to vertical dip; average 15-ft-thick bed; resource estimate
Coaldale Field, Nevada[2]	300	Insignificant	---	---	---	---	Poor quality; thin seams, many partings
Ione Field, California[3]	400	Minimal	---	9 322	2.9	14.8	Lignite used for manufacture of montan wax; very low quality for fuel
Harmony Field, Utah[4] (Southwest Utah Region)	400	1.3 (0.4 recoverable)	Served by Union Pacific	9 123	3.31	26.6	30% recoverable
Kolob Field, Utah[4] (Do.)	400	2012 (805 recoverable)	Served by Union Pacific	8 480-11 430	1.10-7.30	3.2-27.1	40% recoverable—0.8 x 10^6 tons mined 1852-1969; generally low angle homocline; all deep mineable; easy access
Alton Field, Utah[4] (Do.)	500	1509 (754 recoverable)	70 miles to Marysvale (D&RGW); 50 miles to Cedar City (UP)	10 772 (8 580-12 329)	1.3 (0.52-2.3)	9.6 (4.7-14.9)	50% recoverable—includes about 200+ x 10^6 tons of very easily strippable coal; horizontal, thick seams; two zones; little development; no active mines
Kaiparowits Plateau Field, Utah[4] (Do.)	500	7878 + (2,363 recoverable)	75 air miles to Marysvale (D&GRW); Very difficult terrain	11 999 (8 499-14 236)	0.87 (0.26-3.40)	8.96 (3.38-33.03)	30% recoverable—lenticular, thick, multiple, discontinuous seams, 3-5 zones; mining costs relatively high; little previous production, many unknowns for modern development
Henry Mountains Field, Utah[4]	500	231 + (104 recoverable)	80 miles to Sigurd (D&RGW); 100 miles to Wellington (D&RGW)	11 253	0.87	9.4	45% recoverable—about 1/3 easily strippable; coal often lenticular, seams rarely exceed 6-ft thick; deposits dispersed over large area; remote area; little development
Black Mesa Field, Arizona[5]	500	21 000 max (resources)	About 110 miles to AT&SF south	12 325	0.4-2.3	3.4-50.8	1 000 x 10^6 tons strippable; poorly explored in the subsurface; new mines, both strip; exclusive control of Navajo and Hopi Indian Nations
Pinedale Field, Arizona[5]	500	Insignificant	---	---	---	---	---
Deer Creek Field, Arizona[5]	500	Insignificant	---	---	---	---	---
Goose Creek Field, Utah[4]	600	Insignificant	---	---	---	---	---
Tabby Mountain Field, Utah[4] (Uinta Region)	600	231 (69 recoverable)	30 miles to Heber (D&RGW)	8 110-9 895	0.7-1.0	6.6-10.2	30% recoverable—steeply dipping, very remote area; inconsequential production in past

APPENDIX B2 (cont)

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Heat (Btu/lb)	Quality Sulfur (%)	Ash (%)	Mineability and Development
Mt. Pleasant Field, Utah[4] (Sevier-Sanpete Region)	600	249 (100 recoverable)	10 miles to Mt. Pleasant (D&RGW)	12 890	0.8	8.1	40% recoverable—often thin, split, lenticular; best coal seams deep, over 1 000 ft down; essentially no previous production; very little known; future development
Book Cliffs Field, Utah[4] (Uinta Region)	600	3071 (1075 recoverable)	Served by D&RGW	12 762 (7 045-14 220)	0.85 (0.10-3.0)	6.7 (3.4-13.2)	35% recoverable—largest producer in Utah (200 x 10^6 tons); easily mined coal being depleted; heavy overburden mining dictated, thus higher costs; good transportation
Wales Field, Utah[4] (Sevier-Sanpete Region)	600	10 (3 recoverable)	Served by D&RGW	11 466	4.30	14.8	30% recoverable
Sterling Field, Utah[4] (Do.)	600	1.8 (0.5 recoverable)	2 miles to D&RGW	12 483	0.9	6.1	30% recoverable
Salina Canyon Field, Utah[4] (Do.)	600	85 (30 recoverable)	10 miles to D&RGW	12 652	0.45	9.6	35% recoverable
Wasatch Plateau Field, Utah[4] (Uinta Region)	600	6047 (1814 recoverable)	North served by spurs (D&RGW); east 10-70 miles south (D&RGW); 10 miles west	12 589	0.60 (0.23-1.60)	6.5	30% recoverable—more expensive mining; best reserves under 1 000 ft of overburden; often bad rock, seam splits, variable dips, undulations, etc.; largest production in north
Emery Field, Utah[4] (Do.)	600	1425 (428 recoverable)	50-70 miles north (D&RGW) at Wellington; proposed railroad	12 463	0.99 (0.31-4.66)	8.9 (4.0-23.6)	30% recoverable—2 active mines, 140 000 tons annual production; multiple coal seams, undulating seams, roofs, and floors problems; all underground, slightly expensive mining
San Juan Field, Utah[4] (Dakota subregion)	600	Insignificant	---	---	---	---	---
La Sal Field, Utah[4] (Do.)	600	Insignificant	---	---	---	---	---
Nucla-Naturita Field, Colorado[6] (Do.)	600	1375 resource	40 miles minimum south (D&RGW) at Delta, almost impossible route	10 010-13 380	0.5-1.1	6.1-12.8	Very tentative reserve estimate; one strip mine now; many can be deep mined only; difficult exploration in many scattered area; isolated area
Cortez Area, Colorado[6] (Do.)	600	160 + resource	40 miles minimum east (D&RGW) at Durango, but only to east	10 440-13 630	0.5-0.8	5.0-18.3	Generally thin and discontinuous; thicker seams in north; 120 x 10^6 tons strippable; isolated and scattered mining area
Durango Field, Colorado[6] (San Juan River Region)	600	9634 + resource	Partially served by D&RGW, but only to east; L.A. 1500 miles	10 860-14 070	0.6-1.2	3.4-16.6	Scattered mining for local power plant; some stripping coal; some coking coal

APPENDIX B2 (cont)

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Heat (Btu/lb)	Quality Sulfur (%)	Ash (%)	Mineability and Development
Barker Creek Area, New Mexico[7] (Do.)	600	?	25 miles minimum, southeast (D&RGW) going east at Farmington	12 500-14 000	<1	<10	Dips of 10 to 38°; Navajo Nation ownership
Fruitland Field, New Mexico[7] (Do.)	600	158 (strip reserves to 250-ft depth)	20 miles minimum, southeast (D&RGW) going east at Farmington	10 200	0.86	15.0	Fruitland formation; 16-ft seam in south, 50-ft maximum in north; western coal lease in south stripped to supply San Juan power plant; land controlled by Navajo Indians:
Hogback Field, New Mexico[7] (Do.)	600	? (large underground reserves)	25 miles minimum, east (D&RGW) going east at Farmington	12 500-14 000	<1	<10	Substantial reserves of good quality underground coal dips of 10 to 38°; seams to 22-ft thick; Navajo Nation ownership
Navajo Field, New Mexico[7] (Do.)	600	2400 (strip reserves to 250-ft depth)	30 miles minimum, north (D&RGW), east at Farmington; L.A. 1400 miles	9 200	0.72	20.4	Fruitland formation; Utah International lease north 2/3; El Paso Natural Gas south 1/3; Navajo mine produces 7+ x 10^6 tons annually; gasification expected; Indian ownership
Todalena Field, New Mexico[7] (Do.)	600	?	50 miles minimum, north (D&RGW) going east at Farmington	12 500-14 000	<1	<10	Dips of 10 to 38°: Relatively thin seams with thick shale partings; Navajo Nation ownership
Newcomb Field, New Mexico[7] (Do.)	600	85 + ? (strip reserves to 250-ft depth)	50 miles minimum, north (D&RGW) going east at Farmington	?	<1	6.6-13.0	Coal of irregular thickness and limited areal extent; very little exploration work, more needed; Navajo Nation control
Bisti Field, New Mexico[7] (Do.)	600	1800 (strip reserves to 250-ft depth)	65 miles minimum, south to AT&SF at Prewitt proposed railroad	8 900	0.6	18.5	Fruitland formation; largest undeveloped strippable reserve in region; very easily removed overburden; lacks transportation; lenticular seams
Chaco Canyon Field, New Mexico[7] (Do.)	600	31 + ? (strip reserves) (? underground)	50 miles minimum, south (AT&SF) at Prewitt along proposed railroad?	9 870-10 220	0.9-2.2	7.5-10.2	Highly lenticular seams; good thick coal at depth of over 500 ft; very little exploratory work
Standing Rock Area, New Mexico[7] (Do.)	600	125 + (strip reserves)	30 miles minimum, south (AT&SF) at Prewitt along proposed railroad	11 050	0.5	5.2	Lower Menefee; no exposed reserves; few drill holes show strippable reserves; thin and lenticular seams; more information needed; partially Navajo Reservation

APPENDIX B2 (cont)

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Heat (Btu/lb)	Quality Sulfur (%)	Ash (%)	Mineability and Development
Crownpoint Field, New Mexico[7] (Do.)	600	15 + (strip reserves) (large under-ground reserves)	20 miles minimum, south (AT&SF) at Prewitt along proposed railroad	10 600	1	10	Gallup Sandstone and Crevasse Canyon Formation; beds highly lenticular; very little information: hard to strip; partially in Navajo Reservation
Gallup Field, New Mexico[7] (Do.)	600	496 (strip reserves) (? underground)	On mainline (AT&SF) L.A. about 750 miles	10 640-11 840	<0.6	<10	Mesaverde Group; both stripping and under-ground mining in past and present; many commercial seams, all highly lenticular
Zuni Field, New Mexico[7] (Do.)	600	6.2 + (strip reserves) (large under-ground reserves)	20 miles minimum, north to AT&SF at Gallup	10 470-10 570	0.6	16.4-18.6	Gallup Sandstone; thin to medium lentic-ular seams; very little information; hard to strip
Datil Mountain Field, New Mexico[7]	600	1320 (resource)	10 to 65 miles minimum, north to AT&SF	---	---	---	---
Lost Creek Field, Utah[4] (Hams Fork Region)	700	1.1 (0.4 recoverable)	Served by Union Pacific	10 391	0.53	18.5	35% recoverable
Coalville Field, Utah[4] (Do.)	700	172 (52 recoverable)	Served by Union Pacific	11 109	1.32	4.4	30% recoverable; estimated 4 x 10^6 tons production since 1850; one small mine now operating; moderate dips; highly combust-ible; only local market expected
Kemmerer Field, Wyoming[8] (Do.)	700	4077 (measured and indicated reserves)	Served by Union Pacific L.A. about 800 miles	9 671-12 880	0.6	3.57-6.9	1 000 x 10^6 tons strippable; both underground and strip mining; highly folded and faulted; small amount moderate to poor quality coke
Evanston Field, Wyoming[8] (Do.)	700	299 (measured and indicated reserves)	Served by Union Pacific	10 450	0.2 +	7.2	Evanston Formation; thick but lenticular seams; dips 10 to 20°
Henry's Fork Field, Utah[4] (Green River Region)	700	Insignificant	---	---	---	---	---
Rock Springs Field, Wyoming[8] (Do.)	700	7328 (measured and indicated reserves)	Served by Union Pacific	11 320-12 572	0.7-0.8	3.59-6.69	Mostly Mesaverde Group; fairly persistent beds, 2 to 4 ft thick; minor folds and numerous normal faults of various size; dips range 5 to 20°
Henry's Fork Field, Wyoming[8] (Do.)	700	Negligible	40 miles minimum, north to Union Pacific at Granger	---	---	---	---

APPENDIX B2 (cont)

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Heat (Btu/lb)	Quality Sulfur (%)	Ash (%)	Mineability and Development
Vernal Field, Utah[5] (Uinta Region)	700	176 (53 recoverable)	90 miles minimum, southwest to D&RGW: or 75 miles north to UP	11 509	1.6	12.5	30% recoverable—no active mines in 20 yr, total production 250 000 tons; generally thin, split and steeply dipping seams
Sego Field, Utah[4] (Do.)	700	288 (130 recoverable)	5 to 10 miles south to D&RGW	10 940 (9 000-12 150)	0.60 (0.37-1.00)	11.1 (4.2-19.0)	45% recoverable—last production 1970—2.65 x 10^6 tons previous production; thinner seams than other areas, often impure; best for local use?
Lower White River Field, Colorado[6] (Do.)	700	7012 resource	60 miles minimum, south (D&RGW), near Grand Junction; very difficult	10 800-11 230	0.4-0.5	4.4-8.5	No mines operating now; good seams
Book Cliffs Field, Colorado[6] (Do.)	700	2293	East served by D&RGW; rest 20 miles to D&RGW	10 410-13 560	0.4-1.7	4.9-17.4	At least 4 different areas; evidently minor production only
Grand Hogback Field, Colorado[6] (Do.)	700	885	South served by D&RGW; north 30 miles to D&RGW	11 220-13 270	0.3-0.8	3.9-11.3	Some very steeply dipping beds; one small mine operating; 2 seams 5 ft 6 in. to 18 ft 0 in. thick, major producers
Carbondale Field, Colorado[6] (Do.)	700	1136 (over 1/2 coking quality)	5 to 10 miles northeast to D&RGW	10 160 13 530	0.4-2.1	1.9-16.2	Northern half noncoking; southern half in part metamorphosed; at least 50% coking, some anthracite; seams 4 to 16 ft thick; 3 large and 1 small mine operating for coke
Grand Mesa Field, Colorado[6] (Do.)	700	1569	20 miles minimum, south to D&RGW	9 360 11 670	0.5-1.8	2.1-16.1	2 or 3 mineable seams in any one area; seams persistent 4 ft 6 in. to 14 ft thick; 2 small mines operating; flat-lying beds
Somerset Field, Colorado[6] (Do.)	700	3348 (About 1/2 coking quality)	Eastern end served by D&RGW spur	8 160-13 900	0.3-0.9	2.4-13.9	3 large and 1 small mine producing coking coal (eastern half)
Tongue Mesa Field, Colorado[6] (Dakota Sub-Region)	700	---	20 miles minimum, west to D&RGW spur	---	---	---	---
Monero Field, New Mexico[7] (San Juan River Region)	700	Large strip reserves; underground reserves	North served by D&RGW going east. L.A. about 1300 miles	12 160-13 730	0.7-3.5	5.3-10.4	Menefee Formation; small-scale underground mines in past; predictions from geologic projection, very little information; some coking coal
Tierra Amarilla Field, New Mexcio[7]	700	4.4	20 miles north to D&RGW going east	10 000	1.0-1.1	8	Menefee Formation; mostly thin and lenticular; local use mining

APPENDIX B2 (cont)

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Heat (Btu/lb)	Quality Sulfur (%)	Ash (%)	Mineability and Development
Star Lake Area, New Mexico[7] (San Juan River Region)	700	635 + (Strip reserves to 250 ft depth)	60 miles minimum, southwest (AT&SF) at Prewitt proposed railroad	9 400-10 220	0.4-0.7	15-33	Fruitland Formation, thinning to east; maximum seam thickness 16 ft; only fragmentary information; lacks transportation
La Ventana Field, New Mexico[7] (Do.)	700	15 (strip reserves) (large under-ground reserves)	Partially served by AT&SF spur?	10 500	low	---	Menefee Formation; small, intermittently active mines underground; seams 3 to 6 ft thick; gentle to very steep dips; thick sandstone overburden
Chacra Mesa Area, New Mexico[7] (Do.)	700	?	45 miles minimum, southwest to AT&SF	9 870-10 220	0.9-2.2	7.5-10.2	Menefee Formation; highly lenticular seams; coals thin in outcrop; thick deposits down 500+ ft; very little exploration
East Mount Taylor Field, New Mexico[7] (Do.)	700	?	10-30 miles south; 20 miles north to AT&SF spurs	11 200	0.6	6	Crevasse Canyon Formation; coal seams overlain by volcanic rocks; seams highly lenticular; little information
South Mount Taylor Field, New Mexico[7] (Do.)	700	?	10 miles south to AT&SF	11 200	0.6	6	Crevasse Canyon Formation; coal seams overlain by volcanic rocks; seams highly lenticular; little information
San Mateo Field, New Mexico[7] (Do.)	700	21 (x 10?) (strip reserves)	30 miles minimum, southwest to At&SF	11 050	0.5	5.2	Menefee Formation; many thin, lenticular seams; mineable 3 ft –6 ft but up to 12 ft; coal poorly exposed in outcrop, very little data
Rio Puerco Field, New Mexico[7]	700	?	5 to 25 miles north, or 10 to 25 miles south to AT&SF	11 200	0.6	6	Crevasse Canyon Formation; cut by many high-angle faults; coal occurs in steeply dipping fault blocks; mining for local use
Cerrillos Field, New Mexico[7]	700	47.5 (Bitum.) 5.7 (Anthra.)	On mainline of AT&SF	?	?	?	Mesaverde Group; complexly folded, faulted, and intruded syncline; major beds up to 6 ft thick; anthracite extensively mined
Una Del Gato Field, New Mexico[7]	700	17.3	5 miles north to AT&SF	?	?	?	Mesaverde Group; 3 ft-5 ft thick seams cut by numerous faults; several small under-ground mines around 1900s; complex geology and remoteness are negatives
Tijeras Area, New Mexico[7]	700	1.6	---	?	?	?	Mesaverde Group; faulted and folded fault block; thin beds mined for minor local use
Carthage Area, New Mexico[7]	700	30 maximum (coking quality)	About 5 miles west to AT&SF	12 910	0.7	10.6	Lower Mesaverde Group; seam 4 ft-7 ft thick; complexly faulted, mining expensive; only 1 small mine operating for local heating

APPENDIX B2 (cont)

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Quality Heat (Btu/lb)	Sulfur (%)	Ash (%)	Mineability and Development
Jornada Del Muerto Area, New Mexico[7]	700	Unknown	About 15 miles west to AT&SF	?	?	?	Mesaverde Group; no mining, max coal in outcrop 3 ft thick; no drilling but extensive reserves possible
Engle Area, New Mexico[7]	700	Unknown	About 20 miles east to AT&SF	?	?	?	Mesaverde Group; apparent max coal seam thickness 2 ft; very sparse drilling info; some test pits
Horseshoe Bend Field, Idaho[9]	700	Insignificant	---	---	---	---	---
Rogue River Field, Oregon[10]	700	Negligible	---	---	---	---	---
Eden Ridge Field, Oregon[8]	700	Negligible	---	---	---	---	---
Coos Bay Field, Oregon[10]	700	50 +?	Served by Southern Pacific going north.	5 530-10 370	2.0	15	Poorly explored; some strippable
Teton Basin Field, Idaho (Hams Fork Region)	800	Insignificant?	Close to Union Pacific.	---	---	---	---
Grey's River Field, Wyoming[8] (Do.)	800	Negligible	---	---	---	---	---
McDougal Field, Wyoming[8] (Do.)	800	106 (measured and indicated)	115 miles minimum, south to Union Pacific.	?	?	?	Isolated field, some small producing mines
Jackson Hole Field, Wyoming[8]	800	121.49 (inferred)	110 miles minimum, east to CB&Q going east; 150 miles south to UP.	---	Unknown	---	Extremely isolated field
Labarge Ridge Field, Wyoming[8] (Green River Region)	800	Negligible	---	---	---	---	---
Great Divide Basin Field, Wyoming[8] (Do.)	800	732 (indicated)	0-40 miles north of Union Pacific.	7 890-10 000	0.3-5.4	10.0-15.3	Many important seams; lenticular and thick; appreciable stripping reserves; dips to 10°; much is high in sulfur and uranium
Kindt Basin Field, Wyoming[8] (Do.)	800	Negligible	---	---	---	---	---
Little Snake River Field, Wyoming[8]	800	1175 (indicated)	0-50 miles south of Union Pacific	5 000-10 492	0.3-5.0	3.8-25.0	Dips 0 to 35°; many important seams, lenticular and thin to thick; appreciable stripping reserves

Field or Area (Region)	Miles From Los Angeles	Reserves (Mton)	Miles to Nearest Rail Transportation	Heat (Btu/lb)	Quality Sulfur (%)	Ash (%)	Mineability and Development
Yampa Field, Colorado[6]	800	23607 (resource)	Served by D&RGW. L.A. about 1100 miles	10 360-12 560	0.3-0.9	3.4-11.5	Gentle to complex structure, some coal metamorphosed; contains much of Colorado's stripping reserve; now serves power plants, 7 mines in operation; many thick seams
Danforth Hills Field, Colorado[6] (Uinta Region)	800	7854 (resource)	20-40 miles northeast, or 40 to 60 miles south, to D&RGW	10 140-11 970	0.3-1.4	2.2-10.0	Gentle dip, discontinuous but thick seams (to 34 ft); no railroad service; 1 mine (1972) at 4 556 tons per year
North Park Field, Colorado[6]	800	3735 (resource)	35 miles minimum, west or south to D&RGW, very difficult routes	8 840-10 870	0.1-0.9	2.8-13.4	From gentle to steeply dipping beds; some very thick seams; remote area, difficult mining, no active mines
Middle Park Field, Colorado[6]	800	Unknown to insignificant	---	---	---	---	---
South Park Field, Colorado[6]	800	92 + (resource)	35 miles minimum, west to D&RGW	9 780	0.47-0.53	1.3-6.4	Deeply weathered, steep dips; high altitude; all old mines, closed and flooded
Crested Butte Field, Colorado[6] (Uinta Region)	800	244 (resource)	10-20 miles west to D&RGW spur	11 400-14 170	0.4-1.9	3.2-9.1	Folded, faulted, and intruded strata; about 15% metamorphosed to anthracite; 1 small mine operating; some good coking quality
Canon City Field, Colorado[6]	800	217 (100 recoverable)	Served by D&RGW going east	10 110-12 010	0.3-1.1	4.6-17.7	Asymmetrical syncline; some strip mining; nearly 40 x 10^6 tons produced; lots shipped by rail
Walsenburg Field, Colorado[6] (Raton Mesa Region)	800	1190	Served by D&RGW going east and south	11 050-12 880	0.4-1.3	7.2-14.4	76 x 10^6 tons production, but no mines operating 1973
Trinidad Field, Colorado[6] (Do.)	800	11484 resource (90% coking) quality)	Partially served by D&RGW going south; L.A. about 1200 miles	11 430-13 970	0.4-1.1	5.3-21.8	141 mines produced 169 x 10^6 tons coking coal, only one (0.6 x 10^6) now operating
Raton Field, New Mexico[7] (Do.)	800	1500 (coking quality)	Served by D&RGW	14 340	0.6	8.8	Good access, horizontal seams; almost all coking coal; mining essentially continuous since 1870; some stripping coal
Sierra Blanca Field, New Mexico[7]	800	1644 (resource)	10-30 miles west to Southern Pacific	12 220	1.0	14.3	Very difficult to mine because of many faults and numerous intrusions; moderate dips; many sandstone rolls; seams to 7 ft thick
Hanna Field, Wyoming[8]	900	3914 (resource) 274 strippable	0-15 miles to Union Pacific	8 340-11 660	0.26-1.2	3.9-13.6	Easily strippable coal; very good but long transportation to L.A.; currently very active mining

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3. ENERGY TRANSPORTATION

This section concerns transporting energy from a coal mine source to a pumping station sink. The energy may assume many forms along the way, and one of the goals of our cost analysis is to determine the most economical sequence of energy transportation modes. We have confined our study to the three most practicable modes for long-distance energy transportation in the Southwest: coal trains, coal slurry pipelines, and high-voltage electric transmission lines. Other means, such as trucks, barges, and conveyors, were deemed suitable only for relatively short hauls.

This section describes the three main energy transportation modes and then presents possible routes for each between coal sources and power plant sites. The costs of transportation alternatives are discussed in Sec. 4.

3.1. Railroads

3.1.1. Unit Trains.

Definition. Coal is most commonly shipped by one of three types of trains. In conventional freight trains, coal hoppers and other freight cars are intermingled; the trains travel at relatively low speeds and are subject to numerous terminal and switching delays. Dedicated railroads are used exclusively for hauling coal and are usually built where no other railroads exist; the Black Mesa and Lake Powell Railroad, which delivers coal to the Navajo Power Plant in Arizona, is an example. While the definition of a unit train is, for tariff-setting purposes, the result of negotiations between shipper and carrier,[1] it is generally "a complete train of dedicated cars operating on a regularly scheduled cycle movement between a single origin and a single destination."[2] Unit trains operate over the same track networks as conventional freight and carry 40% of all coal moved in the US.[3] We shall assume that all coal used in the study project will be shipped by unit train.

Figure 3-1 shows three typical arrangements for shipping coal by unit train.

> "A long-term contract, large-volume shipments per train and per year, and a single destination are the usual requirements for consideration of proposals to negotiate unit train tariffs. In practice, long-term coal contracts usually cover a minimum period of 10 years with a yearly movement of at least one million tons in shipments of more than 7000 tons per movement."[1]

A 1000-MWe power plant in southern California would meet these requirements.

Rolling Stock and Track. Unit trains consist of up to 150 cars, although a typical train contains 75 to 100 cars, each with 100 tons net capacity.[5] Locomotive horsepower requirements vary from 0.5 to 3 hp per net ton, depending upon terrain and desired speed. Since modern diesel and electric locomotives are rated at up to 3000 hp, 2 to 10 locomotives would be needed for each train. We shall assume that unit trains to haul coal to California will not exceed 100 cars and will require 1.75 to 2 hp per net ton.

Although the number of hopper cars in US service decreased from 390 000 in 1971 to 334 000 in 1975, and there is currently an 18-month backlog on car orders,[6] there do not appear to be major constraints on supplying hoppers or locomotives for unit trains by the 1980s.[7] One of the reasons for this is that hoppers are used more intensively in unit train operations. "Coal cars formerly loaded on an average of once a month are being replaced by unit trains that are loaded as often as every second or third day, depending upon the distance traveled."[8] Since unit trains are a relatively new phenomenon, it is not known yet how much more often their cars must be replaced. One railroad company estimates a 14-yr life for its hoppers,[9] which is slightly above the mean age of open-top hopper cars in service in the US.[10]

Existing major rail lines to southern California from Utah and New Mexico have an excess of capacity and can accommodate future unit train coal shipments. As field inspection has confirmed, however, some of the spur line track is unsuitable for unit train operation. With their uniform weight and length, unit trains set up periodic stress patterns that tend to concentrate wear and distortion at specific points along the track; lighter gauge and jointed rail lines need to be replaced with heavy duty, continuous-welded track.[11]

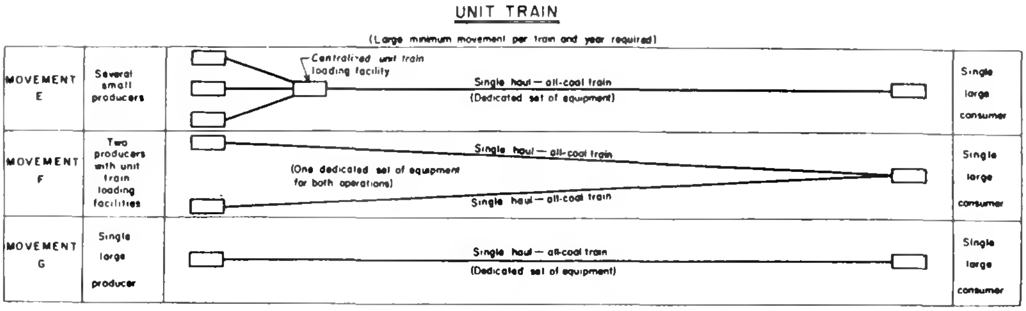


Fig. 3-1.
Typical unit train coal hauling arrangements.[4]

Operation. A thorough discussion of unit train operating times and costs is found in Sec. 4.1.3. Figures reported in this section are illustrative only and are not necessarily those used in the cost model. Unit trains run continuously, with the possible exception of weekends and holidays, stopping only for refueling and for federally required inspections every 500 miles.[8] Average loaded-train speeds, including switching and crew-changing, vary from 18 to 26 mph.[12] On the Black Mesa and Lake Powell, the average loaded-train speed is 28.7 mph; unloaded, 43.3 mph. Including loading (1.5 h) and unloading (0.5 h), the total cycle time is about 6.5 h, indicating an overall average speed of 24 mph.

One of the chief advantages of a unit train system is the relative speed and ease of loading and unloading the cars. "Instead of 40 percent of train time involved in loading and unloading, the modern unit train, under rigidly controlled conditions, can be loaded or unloaded within 3 to 4 hours with virtually no idle time."[8] The following description of loading and unloading operations is excerpted from Ref. 13.

After being crushed and sized, mined coal is stored on the ground or in silos before being loaded on the train. In the first case it lies uncovered until reclaimed either by buried conveyor galleries, wheel or rake-type mechanisms, or by having the ground storage pile open directly over a loading tunnel for the unit train. Silo or bin storage provides protection from rain or snow and eliminates the need for secondary handling during loading. Hoppers can be loaded while stationary or moving. Conveyors move coal up to the loading point in most ground storage systems while silo systems dump directly into the cars.

Two basic unloading systems are employed in coal transport by rail. In the roll-over system, cars are inverted individually or in groups; they may be unloaded individually without uncoupling if each one is equipped with a rotary or swivel couple on one end. Cars are positioned for inversion by the unit train locomotives, a yard locomotive, or by an automatic car positioner.

Bottom dumping requires cars equipped with bottom dumps. Standard sawtooth-type hoppers require a shaker or vibrator, although many new fast unloading hoppers are self-cleaning. Newer cars allow for unloading into track pits while moving at speeds up to 5 mph.

Ownership. About 20% of all unit train gondola cars are owned by mining companies or electric utilities,[8] and the trend is toward nonrailroad ownership. Among the advantages to owning or leasing cars for unit train service are:[14]

(1) Cars are less likely to be diverted to other uses in times of emergency or extreme car shortage.
(2) The mine is assured of being able to load cars previously loaded with coal, thereby eliminating a major cleaning problem.
(3) Cars can be designed for the specific service.
(4) Ownership of the cars can be a factor in negotiating a long-term contract for coal at a delivered price.

3.1.2. The Southwestern Railroad Network.

Existing Lines. One of the attractive features of a Rocky Mountain coal—southern California power scenario is the existence of an extensive railroad network linking the two regions. As will be discussed in Sec. 3.1.3, extensive new railroads would be needed only in southern Utah and northern Arizona.

As seen in Fig. 3-2, three railroad lines connect southern California with the Rocky Mountain states—the Union Pacific through Las Vegas, Nevada; the Atchison, Topeka and Santa Fe (A.T. & S.F. or Santa Fe) through Needles, California; and the Southern Pacific through Yuma, Arizona. All three railroads are capable of carrying heavy freight tonnages at high speeds. In addition, the D&RGW Railroad provides access, through an interchange with the Union Pacific at Provo, Utah, to the coalfields of northern Utah and Colorado.

None of the several mining railroads serving southern Nevada and eastern California during the gold and silver rushes of the early 20th century has survived. There are, however, at least two dedicated coal railroads in the region and several more are in the planning stage. A 78-mile electrified rail line, the Black Mesa and Lake Powell, has been carrying coal from Black Mesa, Arizona, to the Navajo Power Plant at Page, Arizona, since 1973.[15] An average of 28 000 tons per day is transported by a 6-mile conveyor off the mesa to a railroad loading station,[16] then carried in three trips by a 73-hopper unit train.[15] Utah International, meanwhile, has built an 8-mile railroad between its San Juan, New Mexico, mine and the Four Corners Power Plant.

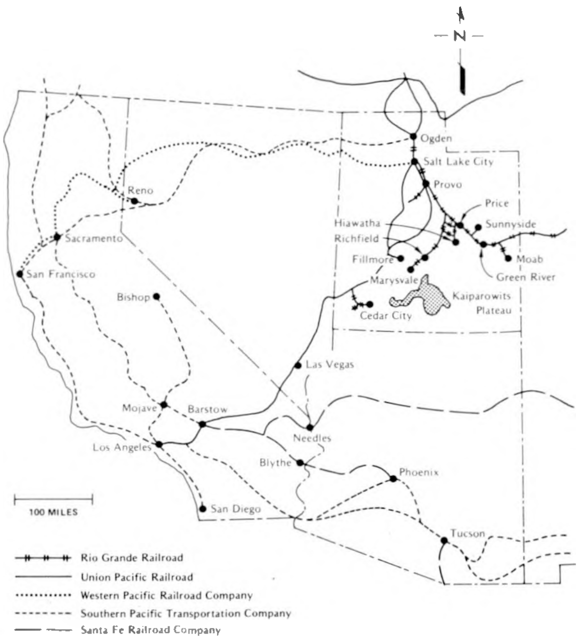


Fig. 3-2.
Railroads of the Southwest. (Source: Ref. 21, p. 46.)

Proposed New Rail Lines. Several new rail connections to southwestern coalfields are under study. Santa Fe Railway will construct a 70-mile branch line from a surface mine at Star Lake, New Mexico, to its mainline at Prewitt.[17] An Arizona company, the Salt River Project, will build a 40-mile connection from the mainline south to its power plant near St. Johns, Arizona. Coal shipments are scheduled to begin in 1978. The railroad expects to haul coal from the mine to other markets in the East and West.[18]

Morrison-Knudsen Co., Inc., of Boise, Idaho, recently conducted a study for a consortium of utilities on the feasibility of a 190-mile railroad to haul coal from the Kaiparowits Plateau to the proposed IPP power plant near Caineville, Utah.[19] The estimated cost of the main route, including equipment, was $450 million. To date, no commitment to construct the line has been made.

Investors in Denver, Colorado, recently formed the Castle Valley Railroad Company to build a 65-mile, $70 million rail line between the coalfields of Emery County, Utah, and the D&RGW mainline near Wellington. The line would be a common carrier available for transport of other items in addition to coal.[20]

Connections With Southern California and Nevada.[21] Coal shipped from southern Utah to southern California would travel by new and existing lines either to the Union Pacific Railroad at Cedar City or the D&RGW at Marysvale or Sigurd (with later transfer to the Union Pacific at Provo). The Union Pacific train would transfer to the Santa Fe at Barstow for final delivery to the eastern California plant sites. The Barstow, Cadiz, Goffs, and Rice plant sites are assumed to be close enough to existing rail lines to require only minor spur construction. Blythe and Glamis would require 16- and 48-mile extensions, respectively, off the Santa Fe line.

Coal from New Mexico would be transported over the new Star Lake-Prewitt line, described above, and to southern California via Flagstaff on Santa Fe's existing mainline. There would be no need to transfer at Barstow, but extensions to Blythe and Glamis would still be necessary.

Coal from Wyoming or northern Utah-western Colorado would be shipped over the Union Pacific or D&RGW, respectively, with a transfer from the latter to the former at Provo, Utah. A power plant at Ely, Nevada, could be served by the Nevada

Northern Railroad; coal trains would transfer from the Western Pacific Railroad at Shafter, Nevada.

3.1.3. Railroad Route Study for Transportation of Kaiparowits and Alton Coal. The purpose of this part of the study was to identify and evaluate potential segments of a new railroad route connecting the Kaiparowits and Alton coalfields with existing railroad mainlines. Distance and cost information generated here was then used to determine the optimum combination of segments, i.e., the optimum route (see Sec. 4.1.2).

It was assumed throughout the study that the route would connect with the Union Pacific or D&RGW; routes to the south were precluded because of attendant engineering and political difficulties.

Methods. In the following discussion, "segment" will mean a path between two towns or rail junctions, and "route" will denote the overall path between a coalfield and an existing mainline; a route comprises segments.

Segments were proposed after examination of 7.5 min. (1:24 000) and 15-min. (1:62 500) US Geological Survey topographic maps. The main criteria for new segments were (1) minimum distance, (2) minimum need for bridges and tunnels, and (3) grades of 1.5% or lower.[22] Segments were drawn on the topographic maps and then plots of mileage vs altitude were made to improve visualization of the topography. Since contour intervals are 20 or 40 ft on the 7.5-min. quadrangles, and 40 or 80 ft on the 15-min. quads, the segment profiles are only precise enough for a preliminary feasibility study such as this. A detailed engineering study (such as that performed recently by Morrison-Knudsen, Inc., see Sec. 3.1.2) would be necessary for a more accurate determination of costs. Figures 3-3 and 3-4 show plan views and profiles, respectively, for a typical segment.

Figure 3-5 identifies all the segments considered, as well as existing railroads, while Table 3-1 summarizes distances and special construction requirements. "Kaiparowits" is the mouth of Tommy Smith Creek (a tributary of Wahweap Creek). This is a relatively flat area, suitable for a mine or for the end of a conveyor from a mine. "Alton" is the town of Alton. Routes marked with asterisks are those that do not require extensive tunnel or bridge construction.

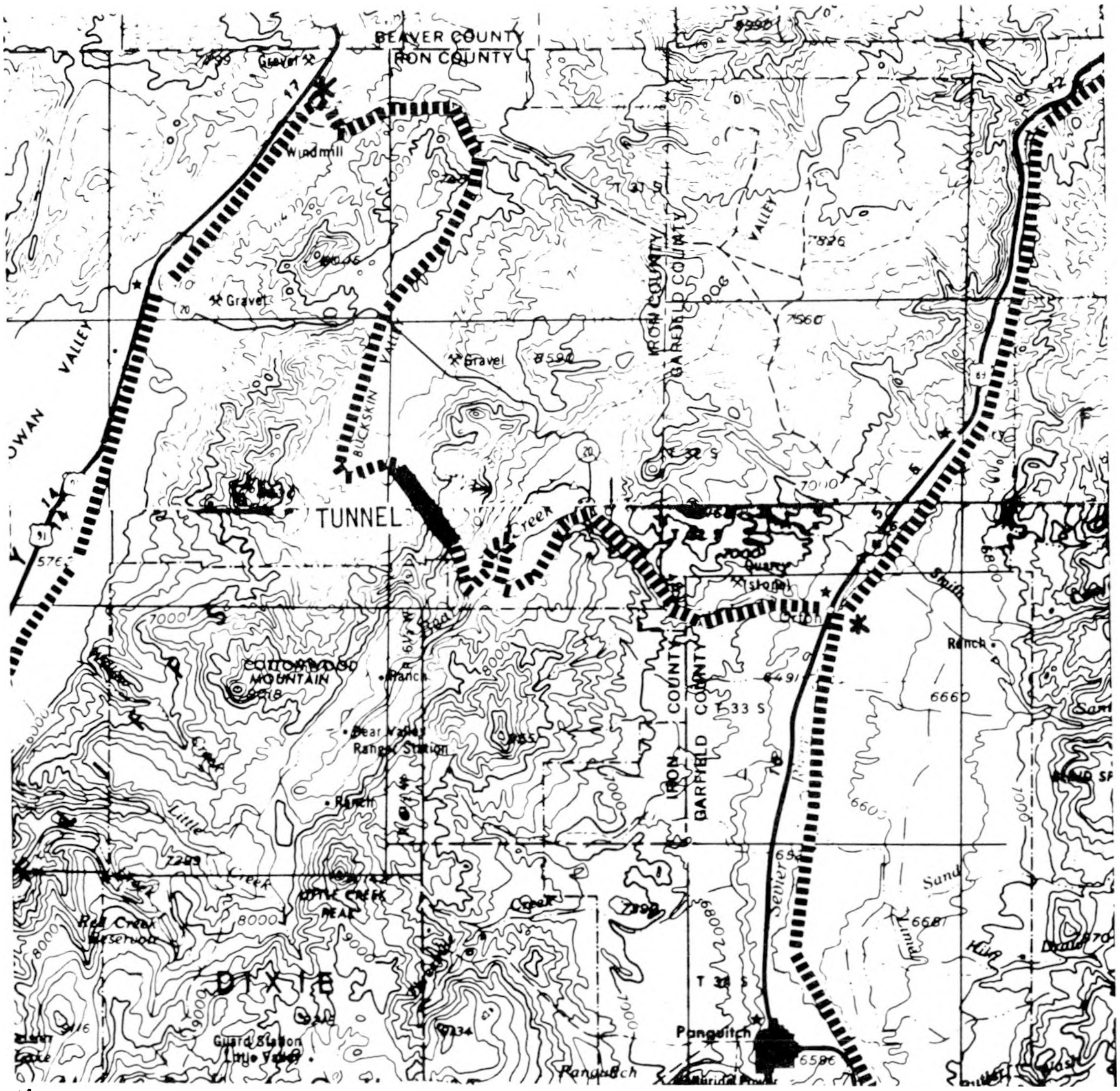
Routes to the West and Southwest. North of the Kaiparowits and Alton areas are the flat-bottomed valleys of the Sevier River Drainage. Mountains with up to 4000 ft of relief separate the valleys, which are interconnected in a few places by narrow canyons. The mountain topography is too steep even for jeep trails in many cases. Highways and secondary roads follow the most gradual slopes possible but have 7% grades in most mountain and canyon areas. Choices for railbeds are therefore limited. Switchbacks, tunnels, bridges, and long cuts and fills would be required for many of the routes. In some cases, such as in a narrow canyon, a steeper grade could not be avoided. Segments with unreasonably high construction costs were rejected early in the study. A description of each segment follows.

A: Sevier to Read. This segment, which follows Utah Highway 4, connects the D&RGW at Sevier with the Union Pacific at Read. The bed for the first 6 miles west of Sevier is at an acceptable grade. Then there is a very narrow section of canyon called The Narrows, and the grade becomes steeper than 1.5%. The highway continues for the next 12 miles at grades of up to 9%. A railroad would require a 10- to 12-mile tunnel to avoid the grades. It should be noted that The Narrows is a scenic canyon used for camping and fishing.

The terrain east of Cove Fort and then along Black Rock Road has an acceptable grade. The last 12 miles are relatively flat.

B: Alton-Bear Valley Junction. This segment starts from the town of Alton, within the Alton coalfield. A 120-ft hill must first be surmounted, probably by contouring and cuts, although a short tunnel might be necessary. The route continues along Utah Highway 136 at grades that are probably negotiable, to US Highway 89 in Long Valley. It then proceeds up the East Fork of the Virgin River to Long Valley Junction. As estimated from a 15-min. topographic map, the canyon is about 300 ft wide and is steep at one point. Switchbacks should be built if there is room.

The terrain along the Sevier River (paralleling US 89) is fairly level until south of the town of Hatch. Exceptions are 2 miles of more or less irregular but not difficult topography below Mammoth Ridge, and an area near Mammoth



Profile shown in Fig. 3-4.

Fig. 3-3.
Typical new rail segment, southern Utah.

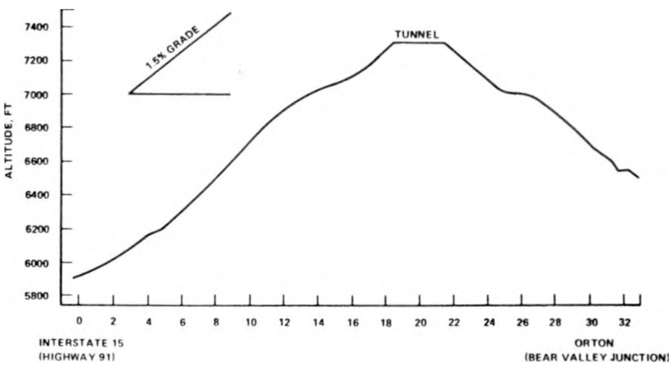


Fig. 3-4.
Typical new rail segment profile.

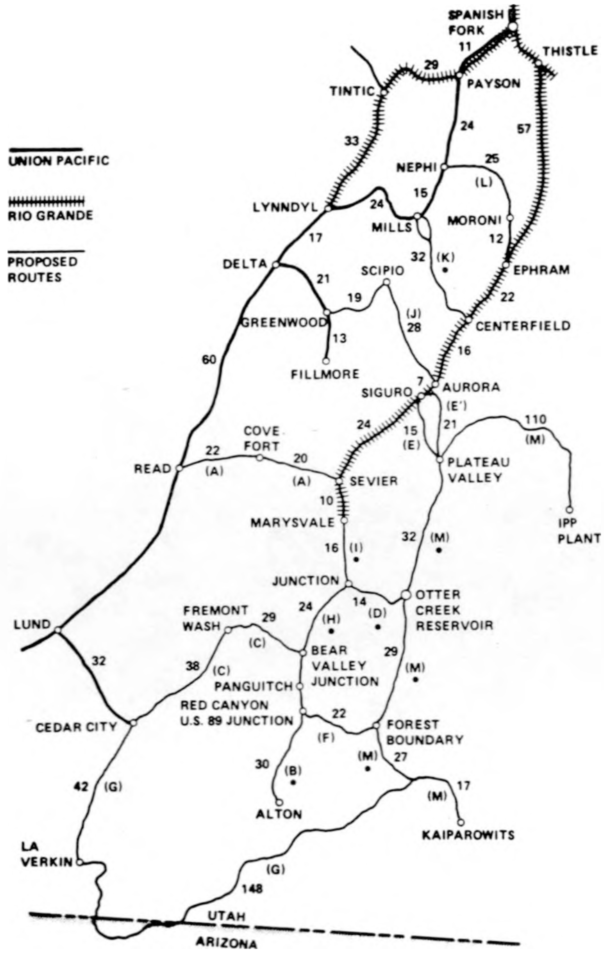


Fig. 3-5.
Existing and proposed new railroad routes, southern Utah.

Creek requiring a fill 80 ft high and 500 ft long. Cuts and fills would also be necessary to flatten a 3% grade south of Hatch. The segment then continues to the town of Panguitch and is quite flat from there to Bear Valley Junction.

C: Bear Creek Canyon. Utah Highway 20 is the shortest automobile road from Panguitch to Cedar City to avoid excessive altitude; all highways in the area between Sevier and Zion climb passes more than 9000 ft high. Utah 20 nevertheless has about 7 miles of grades exceeding 4% on either side of its 7910-ft summit. The first 7 miles of a Bear Valley Junction-Cedar City segment would follow Creek Canyon, where considerable earthwork would allow 1.5% railroad grades. The cheapest route would be to proceed through lower Bear Valley to Buckskin Valley by way of a 3-mile tunnel.

The railroad would then proceed down 7-mile-long Fremont Wash, which drains Buckskin Valley and has 1.8 to 2.1% grades. The wash is about 200 ft wide but narrows in some places. It has a jeep road. The possibility of building a railroad would have to be confirmed by field inspection. From the intersection with Interstate 15 to Cedar City the segment has a 2.5% downhill grade.

D: Otter Creek Reservoir-Junction. This segment would connect the town of Junction with the proposed 190-mile Kaiparowits-IPP Railroad (see Sec. 3-1.2.). Its eastern end would be in Grass Valley near Otter Creek Reservoir. The first part, going through Steens Meadow and into Kingston Canyon, is flat; it loses about 70 ft of elevation in 6 miles. For the other 4 miles, the canyon is about 500 ft wide. One 0.75-mile portion has a downgrade of about 2%, which would be reduced by a cut. Out of the canyon, the terrain—the Sevier River Plain—is flat to the town of Junction.

E: Peterson Creek (Plateau Valley-Sigurd). This segment starts at a point on the proposed IPP railroad[19] assumed to be in Plateau Valley where an access road to Books Hole Reservoir leaves Utah Highway 24. Following the highway to Sigurd would be infeasible for a railroad because of the 2090-ft elevation loss from the drainage divide slightly above Plateau Valley to the town of Sigurd. Most of the highway has a 4 to 5% downgrade in the canyon. If it were possible to meet the 1.5% grade requirements, 27 miles of downgrade would be required. The highway descends this grade in 11 miles, half of them in narrow Kings Meadow Canyon. Building a railroad around the contours of Bear Ridge, Cedar Mountain, and the Rainbow Hills would be extremely expensive.

E': Little Lost Creek. A route following Little Lost Creek north from Plateau Valley has more reasonable grades than does segment E. However, the map shows a small, narrow canyon with a permanent stream for the first 5 miles of the segment. A jeep road is in the canyon. Grades range from 2 to 4% with most around 2%. Field inspection would confirm

TABLE 3-1

SUMMARY OF NEW RAIL SEGMENTS, SOUTHERN UTAH

Map Symbol	Designation	Distance (Miles)	Comments
A	Sevier-Read	42	Very steep grades; 10-mile tunnel needed.
B	Alton-Bear Valley Junction	46	Some cuts; no tunnels; probably no severe construction problems.
C	Bear Creek Canyon	67	3-mile tunnel and much earthwork would be necessary; narrow canyon needs investigating; some 2.1% downgrade.
D	Otter Creek Reservoir-Junction	14	No difficulties apparent.
E	Peterson Creek	31	Probably infeasible; downgrade in canyon is excessive.
E'	Little Lost Creek	21	Has a few 4% grades; canyon very narrow in places.
F	Red Canyon	23	Some severe downgrade; narrow canyon in places; adverse impact on recreation.
G	Southern Terraces	185	Very long; many tunnels and bridges necessary; very rough terrain over about 1/4 of route; very severe construction problems above La Verkin and near pass south of Cedar City.
H	Bear Valley Junction-Junction	24	No grade problems but Circleville Canyon is narrow in places.
I	Junction-Marysvale	16	Some contouring above Marysvale; otherwise no serious problems.
J	Aurora-Holden	47	5-mile tunnel needed to avoid steep grades.
K	Centerfield-Mills	32	No problems.
L	Moroni-Nephi	25	2 to 3% downgrade in narrow canyon.
M	Kaiparowits-IPP Plant	215	Feasible route determined by Morrison-Knudsen Survey; 7-mile tunnel required.

whether the canyon is too narrow. The route follows the creek all the way to Sigurd.

F: Red Canyon. This segment starts at the Dixie National Forest Boundary-Utah Highway 22 intersection, where the IPP railway would enter Johns Valley.[19] It runs southwest for 8 miles to Bryce Canyon Junction, passes through Emery Valley, and enters Red Canyon at the 15-mile point. The next 6 miles are mostly steep downgrades averaging 2.8%. There is no room for switchbacks below 7600-ft elevation. Perhaps a tunnel would reduce the grade, but at least 4 miles of 2.9% downgrade would be present. The railroad would meet US Highway 89 and the flatlands of the Sevier River 2 miles after leaving the canyon.

This segment would pass through scenic Red Canyon, which contains a state campground. Adverse impacts on recreation might be expected.

G: Southern Terraces. This segment would connect Kaiparowits with Cedar City by going southwest from the Plateau. It would begin at the power lines in Horse Valley, where a jeep trail heads down Dry Valley Creek. The route continues down the creek bed, traverses some rough country, tunnels under Shepherd Point, hits the Paria River Bed, tunnels upward to above Sheep Creek, and crosses Sheep Creek Gorge and Bull Valley Gorge near their confluence. Two more miles of very rough country yield to gentler slopes before Swallow Park Ranch and Podunk Creek. Numerous cuts still would be necessary. A 2.5% grade down Deer Wash may be unavoidable. The segment goes through Nephi Pasture and crosses Kaibab Creek and Red Canyon; bridges would be necessary. It then continues for 20 miles through rough country below the White Cliffs. It crosses numerous washes, the major ones being Johnson, Brown Canyon, Kanab Creek and Red Canyon.

The segment crosses US Highway 89 about 14 miles north of Kanab and follows the present road to Colorado City, Arizona. It goes down Rosy Canyon, the only apparent way of penetrating the Vermillion Cliffs for 50 miles west of Kanab. The grade in the canyon is about 1.5%. The land is relatively flat from Rosy Canyon to Cane Beds and Colorado City (Short Creek on old maps). The segment then turns northwest and reenters Utah, proceeding along State Highway 59 over the flatlands of the Big Plain. Twenty miles of rough terrain are encountered after Big Plain. The area above the Hurricane Cliffs is very rugged.

The Hurricane Cliffs are a formidable obstacle; 1000 ft of relief between Gould Ranch and La Verkin must be descended. The only conceivable rail route would contour with switchbacks down the rough areas above the Hurricane Cliffs to the town of Virgin, then would roughly parallel Utah Highway 15 to a point near La Verkin. The highway grade is approximately 6%, so about a 4-mile tunnel would be necessary. Then a mile or so of bridge would probably be necessary to negotiate the rough terrain just north of La Verkin.

Steep grades are then encountered between Anderson Ranch and Toquerville, but there is space for switchbacking up to Interstate 15 near Anderson Junction. The route continues to Kanarraville along Interstate 150. A very difficult 2-mile section is then encountered. Here the highway has a 5% grade over a lava field along Ash Creek. This obstacle may be impossible to overcome. After the grade the terrain becomes progressively flatter until the Union Pacific Railroad is reached near Cedar City.

H: Bear Valley Junction-Junction Town. This segment contours along the gentle topography on or just above the wide Sevier River plain and then enters Circleville Canyon. The canyon is about 7 miles long and is only 200 to 400 ft wide in a few places.

Field inspection confirmed that the canyon can accommodate the river, US Highway 89, and a railroad; however, the highway would have to be partially rerouted and a bridge would be necessary. There are no grade problems. Between the canyon and Junction the terrain is nearly flat.

I: Junction-Marysvale. North of Junction, US Highway 89 and this railroad segment traverse gently sloping land above the Sevier River and Piute Reservoir. The route has little altitude change and few turns until a point about 2 miles south of Marysvale. From there, a way may be found to descend the next 4 miles at a 1.5% grade. About a mile of considerable earthwork would be required. The segment reaches the D&RGW 2 miles north of Marysvale.

We have assumed that a route passing through Marysvale would continue on D&RGW track to Sigurd. Field inspection revealed that the existing track in the canyon between Marysvale and Sevier was in a state of disrepair. At one point it was covered by a small landslide, and plants were growing between the rails in a number of places. On the flatland north of Sevier, near Sigurd, the tracks looked somewhat out of line, suggesting lack of maintenance and use. The trackbed did not appear to be suitable for heavy coal traffic; extensive reconstruction or new construction may be necessary north of Marysvale.

J: Aurora-Holden. Beginning at Aurora on the D&RGW, about 15 miles north of Richfield, this segment ascends Denmark Wash into the Valley Mountains. The narrow canyon has 5 miles of 4 to 5% grades, and a tunnel appears to be the only way to avoid them. Relatively gentle terrain is encountered in Round Valley. From Round Valley into Scipio Valley, the segment can follow the contours at a 1.5% downgrade. Next is a climb from the town of

Scipio to Scipio Pass in the Fishlake National Forest.

A 2-mile tunnel may be necessary to avoid steep grades, unless the 20% sideslopes allow contouring. The rest of the segment is negotiable at a 1.5% downgrade. It would connect near Holden with a Union Pacific Railroad spur that ends in Fillmore.

K: Centerfield-Mills. This segment connects the D&RGW at Centerfield (approximately 22 miles north of Richfield) with the Union Pacific mainline at Mills. It follows Utah Highway 28 on level terrain past Sevier Bridge Reservoir into Juab Valley, then proceeds either north or south of the South Hills. The segment would follow the Old Botham Road to "The Washboard." There are no grade problems until 1.5 miles from Mills, where there is a 50-ft loss in elevation. If the railroad goes north of South Hills, it will encounter a slight hill just south of Chicken Creek Reservoir, where a 60-ft by 0.1- to 0.2-mile cut would probably be necessary.

L: Moroni-Nephi. This route begins at Moroni, at the end of a spur from the main D&RGW line. It follows Utah Highway 11 up slopes that are wide enough for switchbacks. From the summit north of Fountain Green the segment descends through the canyons of Hop Creek and Salt Creek to Nephi. The downgrade is 2 to 3% and the canyon is somewhat narrow.

M: Kaiparowits-IPP Plant. The following description is quoted from the *Salt Lake Tribune.*[19]

The feasibility report (two thick volumes) submitted by Morrison-Knudsen is entitled 'Utah Power & Light Co., Coal-Haul Railroad.'

It traces a proposed route north from a terminal near Fourmile Bench (one of the proposed plant sites for the 3000-megawatt Kaiparowits Project, the same size as IPP). From the plateau the suggested rail route runs northwest, circles south of Grosvenor Arch, Kane County, then continues northwest to enter Garfield County near Henrieville.

Passing through the southwest edge of Table Cliff Plateau in the Escalante Range (involving two tunnels, a total of seven miles long), the proposed line parallels the East Fork of the Sevier River through Garfield County and runs along the east side of Grass Valley through Piute County north to a point in Fishlake National Forest east of Richfield, Sevier County.

From there it would circle east to roughly parallel I-70, pass Fremont Junction, cut through the extreme southwest corner of Emery County, then head generally southeast to the IPP plant site north of Caineville, Wayne County.

Further study of the route was not undertaken in this report, except for a cost estimation in Sec. 4.1.2.

Routes to the South from Kaiparowits. Because of potential political conflicts, routes to the south to Arizona are not being considered at this time. However, a potential route exists from our starting point below Horse Mountain down Tommy Smith Creek and then Wahweap Creek. A feasibility study for access roads conducted for the Kaiparowits Draft Environmental Impact Report states that a paved road with less than 2% grades could be built, although it would encounter hydraulic and road construction problems in the narrow canyon.[28] This route would continue to Flagstaff. The only apparent major obstacle is the Echo Cliffs, where 1000 ft of elevation would have to be lost in 12 miles (for 1.5% grade). This would be extremely costly, even if physically feasible.

Any railroad to the southeast from Marble Canyon would go through the Navajo Reservation. The Marble Canyon crossing is the only way to cross the Colorado by road until Lake Mead. Thus, any other southerly route would have to negotiate 2000-ft cliffs—considered impossible.

Alton South Route. The White Cliffs south of Alton could be descended through Johnson Canyon, Kanab Creek, or the Virgin River. The Johnson Canyon route, followed by Utah Highway 136, could possibly be engineered to a 1.5% grade. Kanab Creek is extremely narrow at its head and has 5% grades. US Highway 89, which follows the Virgin River, must later ascend 1000 ft in 4.5 miles in a canyon too narrow to include a railroad. These routes would need more detailed study if the Alton coalfield is seriously considered.

Virgin River Route. A route southwest from St. George, Utah, may be considered. Interstate 15 follows the Virgin River Canyon, the only means of penetrating the mountainous area southwest of St. George without excessive grade. This route has not been studied in detail because of the difficulty of descending the Hurricane Cliffs and the 270- to 320-mile total distance of new railroad line that would be necessary (from Kaiparowits). Interstate 15 penetrated the canyon by means of very extensive blasting and bridge work. There is barely enough room for the highway in places.

Routes to the East From Kaiparowits. The Straight Cliffs, 600 to 1000 ft high, constitute an impossible barrier on the east side of the Kaiparowits Plateau. The only breaks in the cliffs are the steep, narrow Canyons of Right Hand and Left Hand Colletts; a jeep road ascends the latter. The coal site in the Horse Mountain area is bounded on the north by 200- to 400-ft cliffs and by other steep cliffs, such as the one heading Paradise Canyon, on the east and southeast. Jeep trails on the north have 5 to 10% grades.

One might consider a route northeast to Escalante, then, by a roundabout way, east to the D&RGW at Green River. The route would begin by following Utah Highway 12, where a few miles of narrow canyon with grades up to 8% are encountered. Grades in Upper Valley Creek, above Escalante, are about 2%.

Directly east of Escalante is about 50 miles of very irregular topography. Barriers are the Escalante River and its numerous tributary canyons, the Circle Cliffs, Waterpocket Fold, Grand Gulch, Capitol Reef National Park, the Henry Mountains, and numerous other mesas and gulches.

One possible route from Escalante is southeast toward Lake Powell. Along the base of the Straight Cliffs, the topography is not smooth but a railroad route could be contoured to 1.5%. An existing road to Hole-in-the-Rock at Lake Powell drops 1200 ft in 41 miles. At Fortymile Creek many gulches and arroyos are encountered. It would be easiest to cross the lake east of Fortymile Ridge.

A railroad from Fortymile Ridge to the northwest and eventually to Green River must penetrate the Waterpocket Fold. About 800 ft are lost in 1.5 miles. The most gradual slope available would be about 10%. Thus to reach the Bullfrog Creek area, a 2-mile bridge over the Escalante arm of Lake Powell and a 10-mile tunnel through the Waterpocket Fold would be required.

Utah Highway 276 joins the Bullfrog Basin with Hanksville, passing through the Henry Mountains at 5700-ft elevation. Although the topography is difficult for a railroad, contouring may make a route possible. From Hanksville to Green River the way is fairly flat. The total distance from Kaiparowits to Green River would be at least 235 miles.

3.2. Coal Slurry Pipelines

3.2.1. Coal Slurry Pipeline Systems.

System Description. A relatively new alternative way of transporting coal is by a slurry pipeline system, as shown in Fig. 3-6. Coal is delivered from the mine in 2-in.-diam chunks to a preparation plant, where it is dry crushed and then pulverized by wet grinding and rod mills.[24] The pulverized coal is mixed with an equal weight of water and the resulting slurry is pumped through a pipeline to the power plant. Pumps at 50- to 100-mile intervals along the line maintain the flow. At the power plant, the slurry is discharged to holding tanks, dewatered by centrifugation, and burned. Because the coal particles retain some water, the plant's thermal efficiency drops by about 2%.[25]

The major advantages of a slurry pipeline system are low operating costs and minimum safety hazards and environmental impact. The major disadvantages are high initial capital costs, substantial water requirements, and relatively fixed throughput

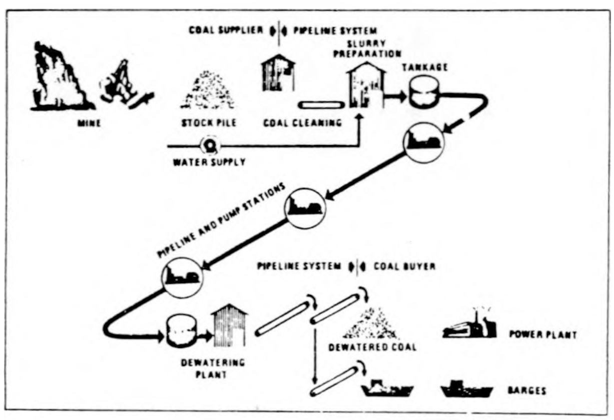


Fig. 3-6.
Typical slurry pipeline system.

capacity.[26] The controversial issue of pipeline rights-of-way is discussed in Sec. 3.4.2.

At present, the only long-distance coal slurry pipeline in operation is the one from Black Mesa, Arizona to the Mohave Power Plant in Clark County, Nevada. It is 275 miles long and can carry 660 tons per hour.[27] The most ambitious line under study is that proposed by Energy Transportation Systems, Inc., to move 25 Mton per year from Wyoming to Arkansas; the 1000-mile, 38-in.-diam pipeline would cost $430 million.[28]

Equipment. Coal slurry pipelines are made of carbon steel coated externally for corrosion protection.[29,30] Standard "production-line" techniques of long-distance, cross-country pipe installation are used. Figure 3-7 shows simultaneously all the steps involved in a typical installation, which takes 3 or 4 yr.[31] Rights-of-way are similar to those for oil and gas pipelines, i.e., from 60 to 100 ft.[32] Slurry lines should be buried below the frost level (2.5 to 3 ft) to prevent the carrier medium from freezing during shutdowns. Since the maximum acceptable slope for a coal slurry pipeline is 16%,[33] switchbacks or extensive cuts may be required. Positive displacement pumps spaced at 50- to 100-mile intervals move the slurry. Commercially available pumps for slurry pipeline service are rated at up to about 1750 hp, with annual throughput capacities of 2 to 3 Mton. This type of pump can develop pressures up to 2000 psi. Positive displacement pumps rated at 4000 hp are currently being designed.

A slurry pipeline system requires storage tanks at each end of the line. At the mine end, mechanically agitated tanks hold the slurry before transmission. Each 6-Mton storage tank in the Black Mesa slurry system has a 500-hp agitator. At the receiving end, the slurry is distributed to a number of holding tanks, from which it is fed to centrifuges for dewatering. The resulting coal "cake," which has about a 25% moisture content,[34] is then fed to pulverizers. The liquid effluent from the centrifuges is collected in another tank, where flocculating agents help settle any remaining suspended coal particles. The concentrated underflow from the tank is returned to the centrifuges by a floc tube.

Pipeline Specifications. Figure 3-8 gives a means of estimating the pipe diameter, given the annual coal requirement in tons per year. We assume a design velocity of 5.5 ft per s, which is consistent with commercial coal slurry experience. For an annual throughput of 3 Mton, the pipeline specifications would be as shown in Table 3-2.

Water Requirement. Figure 3-9 gives a means of estimating the water required annually to transport a given tonnage of coal. Transmission of 3 Mton per year would require about 2300 acre-ft/year. The initial quality of this water is not an important factor. The possibility of obtaining this quantity of water at mine sites in Utah and Arizona has not been investigated.

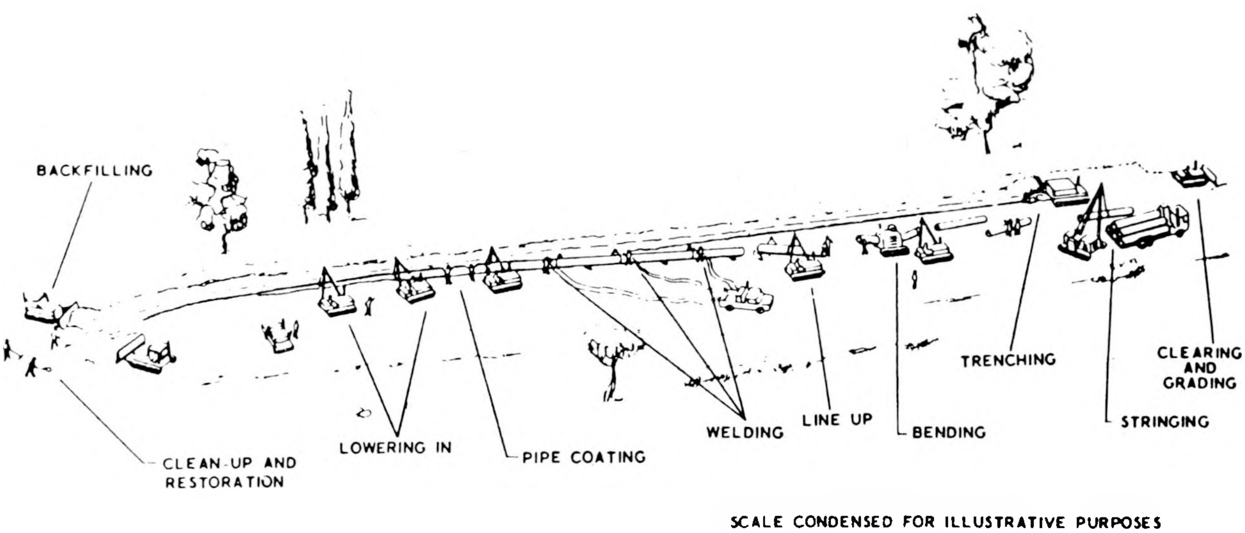


Fig. 3-7.
Method of installing a slurry pipeline.

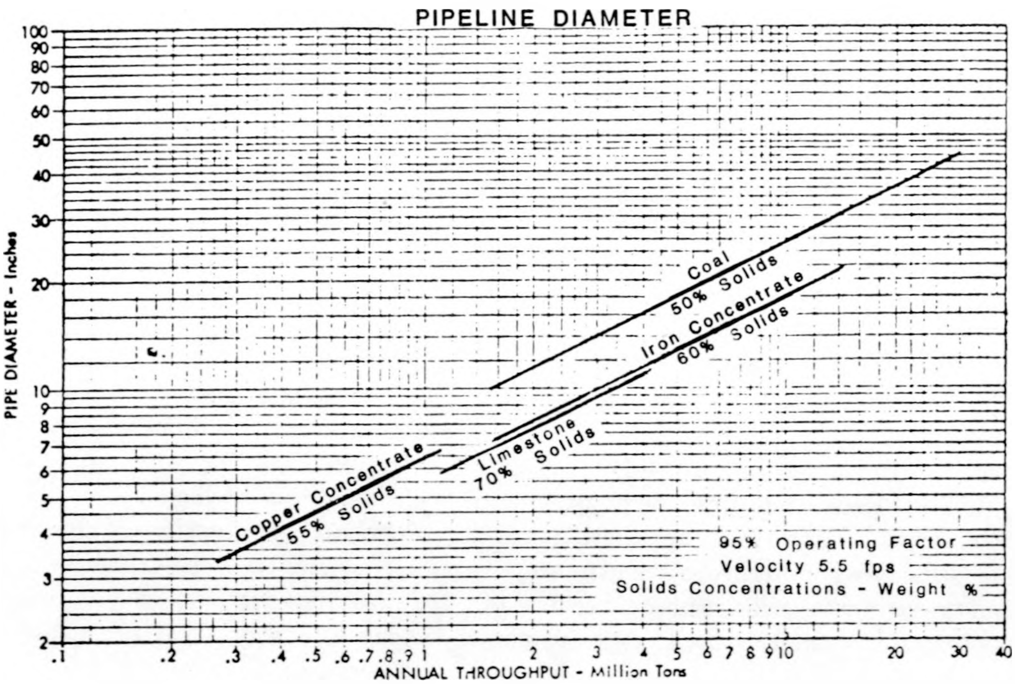


Fig. 3-8.
Estimation of pipeline diameter. (Source: Ref. 31, p. 650.)

TABLE 3-2

COAL SLURRY PIPELINE SPECIFICATIONS

Pipe diam	14 in.
Pipe wall thickness	0.25 to 0.50 in.
Slurry velocity	5.5 ft per s
Maximum grade	16%

The flocculator tank supernatant contains about 23 ppm of suspended solids[84] and may be used for cooling tower makeup, ash-handling, or other plant uses. This water can supply almost one-eighth of the total cooling water requirement, reducing the water demand at the power plant site.

3.2.2. Proposed Coal Slurry Pipeline Routes. Proposed routes from Kaiparowits and Alton coalfields are shown in Fig. 3-10, and Table 3-3 lists the route lengths for various mine-plant site combinations.

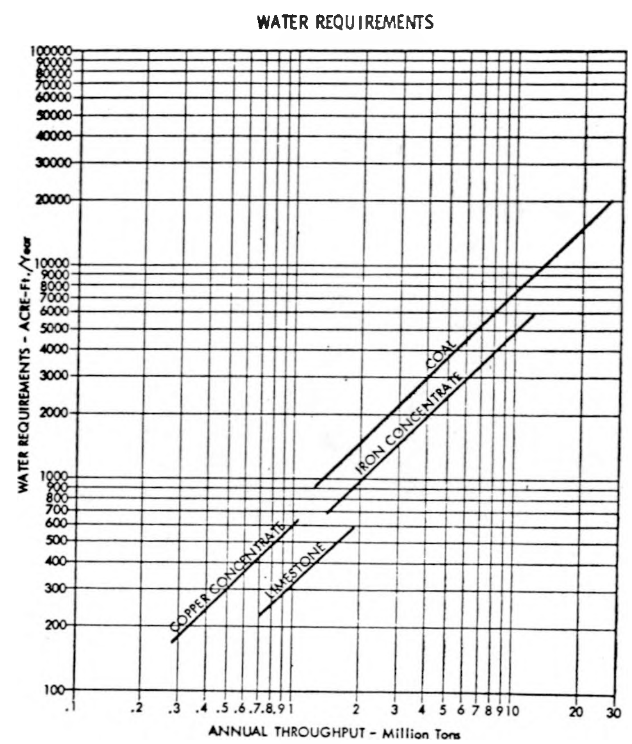


Fig. 3-9.
Estimation of slurry pipeline water requirement. (Source: Ref. 31.)

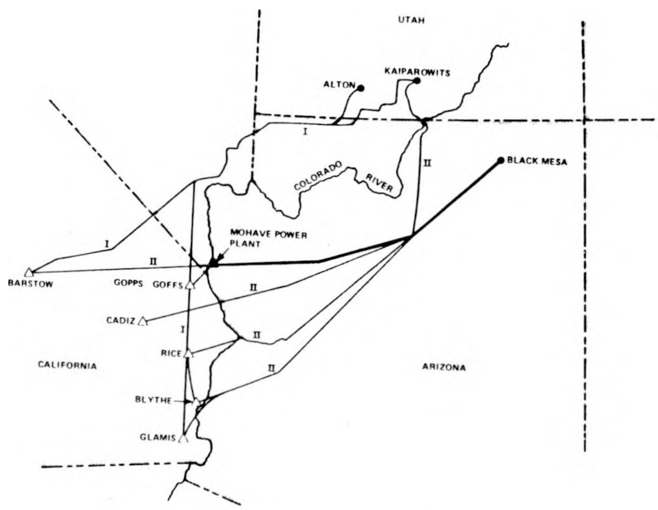


Fig. 3-10.
Proposed coal slurry pipeline routes.

TABLE 3-3

LENGTHS OF PROPOSED COAL SLURRY PIPELINE ROUTES
(Distances in Miles)

	Coal Source			
	Kaiparowits			
Plant Site	**Route I**	**Route II**	**Alton**	**Black Mesa**
Rice	395	350	325	325
Cadiz	350	375	310	350
Goffs	305	335	265	300
Barstow	395	475	355	425
Glamis	445	405	405	380
Blythe	405	370	365	345
Parker Valley	365	330	340	305

Kaiparowits to Southern California Sites.

Route I: From Kaiparowits via southern Utah, northern Arizona, and southern Nevada, to Barstow, Needles, and Cadiz. The route starts from Cow Camp on the Kaiparowits Plateau, goes slightly north and west and comes down from the plateau via Cottonwood Creek. It then parallels US Highway 89 west in southern Utah, enters northern Arizona near Kanab, Utah, and continues west along the border, skirting the Virgin Mountains. The pipeline route then parallels the Virgin River in Nevada and goes along Nevada Highway 12 up to its intersection with California Highway 41. From there it goes almost straight to Barstow, Needles, and Cadiz.

Route II: From Kaiparowits via Utah and Arizona, to Rice, Palo Verde, Glamis, and Parker Valley. This route starts at Cow Camp, descends the Kaiparowits Plateau via Four-mile Wash and Tommy Smith Creek, and then goes along Wahweap Creek. It runs along US Highway 89 toward the southeast, crossing the Colorado River by the Marble Canyon Bridge. It continues south along US Highway 89 in Arizona, almost to Cameron. From this point the pipeline can run nearly straight to Parker Valley, Rice, Palo Verde, and Glamis.

Alton to Southern California Sites. After coming down from the Alton amphitheater, the pipeline goes south and slightly west until it joins with Route I on the west side of the Kanab Indian Reservation, Arizona. From there it follows Route I to southern California.

Black Mesa to Southern California Sites. The pipeline follows the existing Black Mesa pipeline route almost to Cameron, Arizona. From there it follows Route II to southern California.

3.3. Electrical Transmission

3.3.1 Electrical Transmission Systems.

Introduction. Power produced by the steam-driven generators will be converted to 500 kilovolts (kV) by large transformers and then transmitted by extra high voltage (EHV) overhead powerlines to the point of use. At the terminal end of the transmission line another set of transformers will lower the potential to a suitable level. The generators, transformers, and transmission lines are protected by circuit breakers, relays, and line compensation devices.

Transformers. Electrical energy is transformed for three-phase transmission at 500 kV by banks of three single-phase generators rated at a minimum of 1000 MVA. These units have very high efficiencies; only about 5% of the power generated will be lost in the transformers and the transmission lines.[35,36]

Transmission Lines. The three conductors required for three-phase ac power transmission are suspended from towers by large insulators and are separated by about 30 to 40 ft. This spacing is maintained to prevent sparking, called "flashover," between adjacent conductors.[37] If two wires have slightly different amounts of sag, their oscillation frequencies will also differ. A high wind could force the conductors close enough together that a spark could jump between them. Flashover causes a short circuit across the power plant output transformers.

Flashover may also occur when ice, fog, mist, or dew lowers the dielectric strength of the insulator enough to allow current to flow from the transmission cable to the ground via the tower; this overloads the output transformers at the generating station. Finally, a lightning bolt striking a transmission line or tower may cause flashover between the transmission line and the tower.[37,38]

The transmission cable is composed of aluminum reinforced with steel, and formed in bundles of several strands to minimize corona losses and radio interference. Ground cables are usually suspended above the conductors to protect against outages caused by lightning strikes.

Protective Equipment. The generator-transformer-transmission line system is protected from overload by a complex network of circuit breakers, relays, and switches. This protection network is as essential to reliable service as are the power-handling components. Extensive monitoring of the entire power system is performed automatically and continuously. In many cases, the monitoring systems initiate actions directly; in others, they merely serve to notify the operators of trouble.

Some of the actions directly performed by this protection system are (1) isolation of overloaded circuits, (2) temporary opening of transmission circuits if flashover occurs,[39] (3) adjustments in line compensation, and (4) isolation of defective equipment.

Line Compensation. Line compensation controls the phase angle between current and voltage to (1) increase the power capacity of a transmission line, (2) increase the distance over which power can be efficiently transmitted, (3) control the voltage gradient on powerlines, (4) increase the stability of the system, and (5) divide the power between the conductors most effectively. A characteristic of the transmission lines known as "through reactance" limits the power that can be transmitted. The through reactance depends on a number of factors including load, thus, it is desirable to change line compensation as the load varies.

Three devices commonly used to effect line compensation are (1) shunt reactors, which improve system characteristics under conditions of light load; (2) series capacitors, to improve system characteristics under conditions of heavy load; and (3) synchronous condensers, which may be used as shunt reactors or series condensers.

3.3.2. Alternating Versus Direct Current Transmission.

Alternating Current Capacity. The capacity of an ac transmission line is a complex function of many variables and cannot be expressed by a simple formula. Figure 3-11 shows relationships derived from a federal study.[40] The figure shows that for distances greater than 275 miles, a single 500-kV circuit cannot deliver 1000 MW. The maximum distance over which two 500-kV circuits can conduct 1000 MW is about 700 miles.

Alternating Current Transmission Losses. Transmission losses arise from three sources. First, about 1.7% of the generated electricity is lost from transformers, switches, and safety equipment at transmission line terminals.[41] Second, resistance heating in the transmission line consumes about 10 MW per 100 miles.[40] Third, corona and reactive losses total about 2 to 4 MW per 100 miles.[41]

Direct Current. In many cases, dc transmission is an attractive alternative. Power is generated and stepped up exactly as for ac transmission, but is rectified before it is transmitted. At the receptor site,

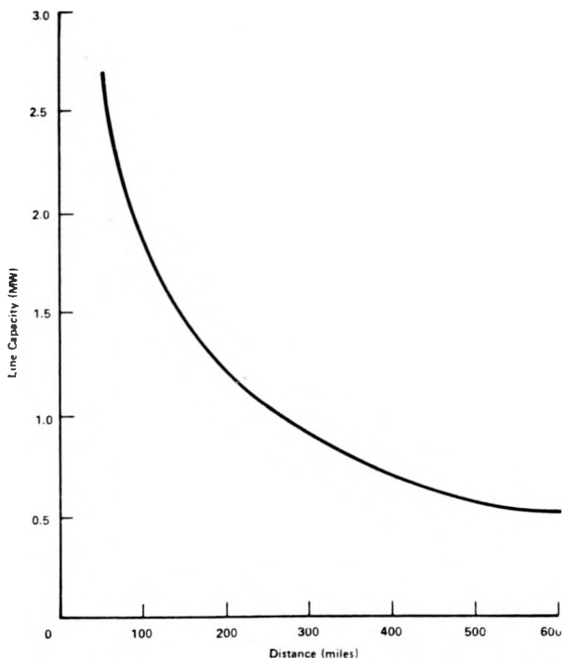


Fig. 3-11.
Power transmission capability of a 500-kV line as a function of transmission distance. (Source: Ref. 40.)

the power must be converted to ac before it can be used. The rectifiers and converters increase the costs of and energy losses at the terminals; however, the transmission line costs and losses are lower for dc transmission than for ac. Two 500-kV ac lines costing \$610 000 per mile can be replaced by a single 80-kV dc line costing \$210 000 per mile. Losses for the dc line are 7.2 MW per 100 miles, and the ac line losses 10 MW per 100 miles.[42]

Comparisons Between ac and dc Transmission. Both ac and dc systems provide good secondary power transmission capability. Since there are two ac circuits, sufficient capacity would remain to deliver at least 500 MW if one of them fails. The dc line has two conductors; if one of them fails, the circuit can still be used with an earth return, although at a reduced load.

In addition to its lower costs and losses, dc transmission has a few other advantages. Corona losses in fair weather are less than or equal to those for ac transmission. In foul weather, ac corona loss can increase by a factor of 100, while dc corona loss increases only by a factor of 5.[43] Direct current radio interference decreases in foul weather, and ac interference increases. Finally, dc lines and towers are smaller and therefore have less visual impact.

Direct current lines may not be tapped at intermediate points, so they are not as versatile as ac lines. It will be more difficult to interconnect with existing electric utilities and facilities if dc transmission is used.

3.3.3. Transmission Alternatives for Southern California Plant Sites. Electric power may be transmitted from a southern California plant site to Edmonston directly, by "wheeling," by displacement, or by a combination of these. The final choice will depend upon arrangements among the utilities and on the requirements imposed by the Federal Power Commission and the California Public Utilities Commission. Since it is cheaper than dc transmission over relatively short distances, an ac system would be used for southern California plant sites (see Sec. 4.1.4).

The choice of a transmission system will also depend on whether the power plant is independent or becomes a part of the Lower Colorado River region interconnected power system. It is not clear which of these situations would pertain, but it appears that the Federal Power Commission would require

Southern California Edison, the Los Angeles Department of Water and Power (LADWP), and the Metropolitan Water District of Southern California to interconnect with DWR facilities (see Sec. 3.3.5). Transmission costs are discussed in detail in Sec. 4.1.4.

Alternative I: Independent, Direct Route. By this alternative, power would be delivered to Edmonston via a 500-kV, single-circuit transmission line. Arrangements for secondary transmission could be made if desired. Table 4-28 lists the distances between each proposed power plant site and Edmonston. Backup lines, connected to pre-existing electrical transmission networks, would enable the power plant to continue operating, though at a much reduced load, in the event that the mainline fails. Power delivered by the backup line would be delivered to Los Angeles by Southern California Edison's 500-kV line. From Los Angeles it could be "wheeled" to Edmonston or it could be used to displace power that normally flows to Los Angeles from northern California; in the latter case, the "freed" northern California power would be delivered to Edmonston.

Alternative II: Wheeling. Wheeling, or transporting electricity over another utility's lines, is commonly practiced by interconnected utilities, both in emergencies and in normal operations. A wheeling for Cadiz would be to build a 100-mile, single-circuit, 500-kV line to the alternative LADWP substation at Lugo, near Victorville. The power would be transmitted from Lugo to Los Angeles via an existing 500-kV line, and it would be wheeled from Los Angeles to Edmonston. Secondary transmission would be as for Alternative I.

There are several drawbacks to this alternative. First, the 85-mile line from Lugo to Los Angeles would probably require an additional circuit because, generally, a 500-kV circuit is needed for each 1000 MW transmitted. This would cost about \$150 000 to \$200 000 per mile.[44] Second, the additional 1000 MW would represent an 18% increase in the amount of power distributed by the LADWP. It is doubtful that they could handle this extra power without a new line from Lugo to Edmonston.[45] Finally, it appears that these drawbacks will cause this alternative to be more costly than I and III.

Alternative III: Displacement. Large quantities of power are transmitted from northern California to the Los Angeles area. The power from a southern California coal-fired plant could be transmitted to Los Angeles as in Alternative II, and the northern power could be transmitted to Edmonston. This displacement could be attractive to all parties involved, since it could reduce transmission costs and distances for all of them.

One particularly good possibility for a displacement agreement exists with the proposed LADWP San Joaquin nuclear project. If the power from the nuclear plant were delivered to Edmonston and coal-generated power were delivered to Los Angeles, then both DWR and LADWP could realize savings on construction costs for new transmission lines.

3.3.4. Transmission Alternatives for Utah and Nevada Power Plant Sites. We also considered power transmission from proposed plant sites in central Utah and White Pine County, Nevada. Given the relatively long distances involved, ac and dc transmission systems are competitive, and only a detailed engineering analysis can determine which is better for a particular situation. The selection of a transmission corridor is a complex problem compounded by political and legal constraints. The potential routes presented here are only a representative sample of available corridors.

Figure 3-12 shows eight possible routes to southern California from Utah and Nevada. The letter N denotes routes from the Nevada site and U indicates routes from Utah. All routes except N-1 and U-1 are parallel to existing power transmission corridors. U-1 and N-1 are the shortest possible, and therefore the

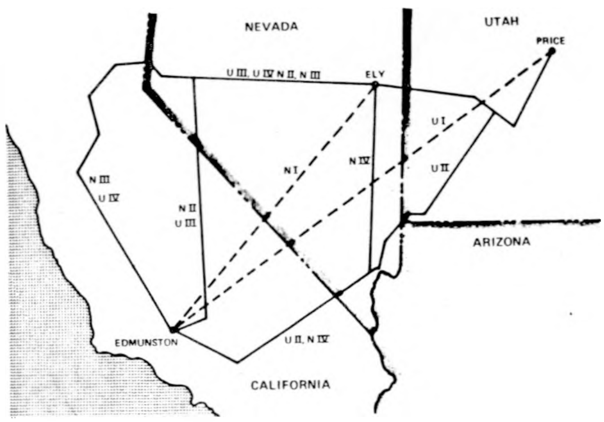


Fig. 3-12.
Possible power transmission routes from Utah and Nevada to southern California.

cheapest, routes. The costs of Utah and Nevada routes are discussed in Sec. 4.2.4.

3.3.5. Interconnection of Electric Facilities.

Advantages of Interconnection. The DWR would benefit in several ways by integrating its proposed coal-fired power plant with the Lower Colorado River region interconnected power system.

(1) If the main transmission line from the power plant to Edmonston fails, power could still be transmitted to the pumping station via alternate lines. Displacement might also be used to provide power at Edmonston.

(2) If the DWR plant is forced to shut down temporarily, the other interconnected utilities could supply power to Edmonston.

(3) The DWR could sell excess power to other utilities. This is a very significant benefit since an idle 1000-MW plant incurs a large opportunity cost.

(4) Interconnected utilities continually strive to produce and deliver electric power at minimum cost. The construction of new power plants and/or population shifts could make a displacement arrangement very attractive. By being integrated into the Lower Colorado River system, the DWR could easily make such arrangements.

The benefits of interconnection are not limited to those that would be received by the DWR. The other interconnected utilities could reduce their reserve capacities and diversify their loads, thereby reducing idle time.[46]

3.4. Legal Constraints Regarding Rights-of-Way

Each of the proposed alternatives for siting the DWR plant requires the acquisition of rights-of-way for coal transportation and electrical transmission lines. Because failure to acquire the necessary rights-of-way could halt the entire project, planning and negotiations for these rights should begin at the earliest possible time. While it should be possible to acquire all the rights-of-way needed for this project, their acquisition may be difficult in actual experience.

As the experience of other utility companies has shown, many of the necessary rights-of-way can be secured over public lands. Where private landowners are unwilling to allow transmission lines or a pipeline to cross their property, or where they demand an exorbitant fee for access, or where land is owned by a railroad opposed to the idea of a competing slurry pipeline crossing its rights-of-way, the availability of eminent domain is an essential prerequisite to completion of the project.

Where the rights-of-way for the entire project cross different jurisdictions, the coordination among appropriate agencies becomes a difficult problem, calling for early resolution.

3.4.1. Eminent Domain—General Problems. The acquisition of rights-of-way for this project may well depend upon the availability of eminent domain condemnation.[47] Within California, the DWR has the power under eminent domain statutes to condemn property for its projects.[48] However, where property interests for a project are to be acquired outside California, certain possible limitations upon the use of condemnation proceedings must be considered. These legal limitations upon the extent of the eminent domain power which may be granted by the state legislatures could be used by persons trying to block the routing of rights-of-way for this project.

The state courts of California have no power to authorize a taking of property outside the territorial limits of California.[49] Furthermore, one state may not take or authorize the taking of property situated within its limits for the use of another state.[50] The concept that eminent domain is a right of public necessity inherent in a state for its own public use has been the basis of a line of cases holding that condemnation of property by eminent domain must be for the public use of the state which is exercising the power.[51] This does not, however, foreclose the possibility of using eminent domain in another state for the proposed DWR project. A state may authorize a foreign corporation organized to do business within that state to condemn land within that state's boundaries where the taking is for an in-state public use.[52]

Where a project for which eminent domain is sought will benefit users outside the state in which the property is located, there must also be a direct benefit within the site state from the use of the facilities.[53] This matter has not been litigated often and it is unclear what nature and extent of direct benefit the courts would require if this issue were raised with regard to the proposed DWR project. The Wyoming Supreme Court held in a leading but dated case, that where a Colorado corporation sought to condemn Wyoming land for an irrigation ditch to serve Colorado farms, the incidental economic benefit to Wyoming from agricultural development in Colorado was not sufficient to constitute a public use for which condemnation would be allowed.[53]

Nevertheless, if there is some direct benefit to the citizens of the state in which condemnation is sought, the relative amount of direct benefits accruing inside and outside the condemning state is not material.[54] Courts have held that incidental benefit to a neighboring state will not defeat the right of eminent domain.[55] For this reason, eminent domain would be available in other states to a DWR project if for example, the project were operated as a joint venture with in-state utility corporations or if part of the power generated were made available to consumers in the condemning state.

Foreseeing the possibility of litigation on this issue, Southern California Edison was attempting to have Utah Power and Light use the uncommitted power from its now abandoned Kaiparowits plant.[56] DWR might consider such a move if it locates a plant or seeks new rights-of-way in other states.

If such sharing of the generating plant output is not practical, it would be necessary to argue an expanded "public use" theory to overcome a challenge. It is unclear just how direct the benefit to the condemning state must be; the law in this area should be updated. In the case of a slurry pipeline crossing a state where no coal is mined, the benefit to that state is likely to be very meager after the initial construction of the line. On the other hand, for a state where the coal was to be mined for the proposed DWR project, the construction of a slurry line would greatly aid the development of the state's resources.

Utility companies have found that most of the necessary rights-of-way over private land can be acquired by private negotiations, with few situations requiring the filing of an action.[57] Of those actions filed, most are settled without litigation.[58] Usually the issue of public use within the state is not raised. For example, the dc transmission line from the Bonneville Project on the Columbia River to southern California successfully exercised eminent domain in Oregon and Nevada even though the line cannot distribute power except at either end.[58] Furthermore, since railroad companies are common carriers licensed within each state where they operate, use of rail transportation would avoid this line of argument.

While it is entirely possible that the issue of public use may never be raised in the acquisition of rights-of-way, it is a potential source of litigation and delay for the project if the Department of Interior locates facilities outside the state, without joining utilities of those states in the project.

3.4.2. Coal Slurry Pipelines. Slurry pipelines are used for coal transportation in several of the scenarios considered in this report. It is clear from an examination of state and federal law that provisions for rights-of-way do not explicitly recognize this relatively new technology. In addition, because slurry pipelines are not expressly mentioned in the language of state provisions for eminent domain, it is not certain whether condemnation of private and state public lands will be possible.

In the Western States that might be crossed by facilities of the proposed project (California, Nevada, Utah, Arizona, Wyoming, Colorado, and New Mexico), the alternative routes for rights-of-way necessitate crossing large tracts of federal public domain land. While it may be desirable—for administrative reasons—to avoid crossing national forests and national parks, Indian land, or other federal reservations, the legal climate surrounding acquisition of such rights-of-way will also be discussed in this section.

Federal Lands. The Act of February 15, 1901,[59] gives the Secretary of the Interior the power to grant permissive use of rights-of-way across federal land for various purposes, including "pipes and pipelines." Since no specific provisions exist for slurry lines, applications for permits are currently made under this Act[60] and several permits have already been granted.[61]

Under the language of the statute, the approval of the head of the Department of the Interior having jurisdiction over national parks and other reserves is required. According to the applicable regulations, separate applications must be filed with various permit-issuing agencies within the Department of the Interior, such as the Bureau of Land Management, National Park Service, and the Fish and Wildlife Service.[62]

Authority to grant rights-of-way over national forests under the Act rests with the Secretary of Agriculture.[63] The fee to be charged for use of rights-of-way over federal public land is the fair market value of the permit[64] and "reasonable charges as specified by the Chief of the Forest Service for National Forest Land."[65]

Thus, for all the federal land that might be crossed by a slurry pipeline in this project, statutory authority exists under which permits might be issued. But the rights-of-way granted by agencies under the 1901 Act would be merely revocable permits[66] because coal slurry pipelines are not included in the provisions of the Mineral Leasing Act regarding rights-of-way for oil and gas pipelines,[67] nor are they specifically provided for under any other rights-of-way statute. Since no specific reference is made to coal slurry lines in the statutes, it is conceivable that such a right-of-way might be challenged by an environmental group seeking to thwart construction of the proposed project. However, at the present time, the gap in the statutes' language does not appear to be the major problem facing the construction of slurry pipelines. Pending federal legislation would clarify the status of coal slurry pipelines.[68]

Indian Lands. Although coal slurry pipelines are not specified in the statutes concerning rights-of-way over Indian lands, authority does exist for the Secretary of the Interior to grant rights-of-way for "all purposes."[69] The rights-of-way across Indian land for the Black Mesa Pipeline in Arizona was granted under these statutes pursuant to regulations promulgated by the Department of the Interior.[70] Although a right-of-way can thus be acquired across Indian land, the greatest potential for delay or even denial of the right is the provision in the regulations requiring that written permission of the Indian owners be obtained.[71] Full market value and severance damages must be paid,[72] along with any other damages incidental to construction and operation.[73]

State Eminent Domain Provisions. In addition to crossing federal lands, slurry pipelines proposed in this report would require rights-of-way across private and state-owned lands. Although the bulk of these rights-of-way would undoubtedly be acquired through private negotiations without need for legal action, eminent domain would be necessary where these arrangements could not be made. In addition, certain proposed rights-of-way would cross state parks, for which permits would have to be filed. It is important to keep in mind the general problems discussed above, which might preclude the use of eminent domain condemnation for a DWR project outside California.[74] However, assuming that those issues can be resolved favorably, there is still the question whether coal slurry pipelines would be considered a use for which eminent domain has been authorized by the state legislatures.[75]

California. Under the 1976 revisions of the Code of Civil Procedure, the public uses for which eminent domain is available are no longer enumerated. Where the legislature has designated a particular use or function as one for which condemnation is authorized, "it is deemed to be a declaration...that it is a public use."[76] Pipeline companies that transport "crude oil or other fluid substances except water through pipelines"[77] are authorized to condemn property by eminent domain.[78] Here, as in the other states with broad statutes, it is an open question whether a court would decide that the language includes coal slurries if the exercise of eminent domain under these provisions were challenged. However, in California, DWR itself is expressly authorized to acquire by eminent domain "any property for state water and dam purposes."[79] Since a slurry pipeline would be a part of a large water project, condemnation under those provisions would likely make the prospect of a right-of-way within California much stronger.

Nevada. The Nevada eminent domain statute provides that a public use includes "pipes...to facilitate...the working of mines and for all mining purposes."[80] This provision indicates that it would apply to slurry pipelines used to deliver extracted coal. Nevertheless, judical or legislative clarification would be helpful in evaluating the prospects of using eminent domain in Nevada for the DWR project. The director of a Nevada Power Company project that includes a proposed slurry pipeline from Alton, Utah, to a plant in Arrow Canyon, Nevada, indicated that in his opinion, eminent domain would not have been available, although it has not been necessary in that project. Nevada Power did not test the statute,[60] so new legal ground in Nevada will be trod if eminent domain is sought by DWR for a slurry line and challenged by land owners. It should be noted that, while not mentioned in the eminent domain statute, coal slurry pipelines are recognized as public utilities in the public utilities section of the Nevada code.[81]

Utah. Utah recently amended its laws to specifically include "coal pipelines" as a public use for which eminent domain is available.[82] Utah law provides that private land, state land not appropriated to a public use, and property already appropriated where the new public use is proved superior, are subject to condemnation.[83] Easements and rights-of-way condemned under the statute are taken, subject to later being joined or crossed by other public uses entitled to exercise eminent domain.[84] The specificity of the Utah statute therefore makes eminent domain readily available for the acquisition of rights-of-way, provided the project can be shown to constitute a public use for the State of Utah.

Arizona. The applicable statute in Arizona confers the right of eminent domain upon "pipelines to carry petroleum products, or any liquid."[85] On its face, the statute is possibly broad enough to include coal slurry pipelines. However, the experience of the Black Mesa Pipeline suggests that eminent domain may not be available. In the opinion of many, the statute did not contemplate coal slurry pipleines, and it was never tested.[86] There was also a reluctance of the pipeline company, a railroad subsidiary, to sue Santa Fe railroad. After lengthy negotiations, an easement was granted by Santa Fe without condemnation proceedings. It is not at all clear, then, whether the Arizona statutes grant eminent domain to slurry lines. As in Nevada, fresh legal ground might have to be broken if a right-of-way is sought under its provisions.

Other States. If a slurry pipeline were constructed to reach mine sites in other Western States, the attempted use of eminent domain to acquire rights-of-way would be plagued by the same uncertainties. The Colorado statute[87] is broad enough to include slurries but, in the opinion of the Colorado State Attorney General, only if for the benefit of an in-state customer.[88] The Wyoming statute[89] does not specifically mention pipelines, and pipelines are not included in the list of public utilities to which the New Mexico state legislature has granted the right of eminent domain for rights-of-way.[90] In these states, unless there is a revision or clarification of the statutes, it is uncertain whether the exercise of eminent domain for this project would withstand a legal challenge.

Assessment of State Eminent Domain Availability. Generally, with the exception of Utah and California, if condemnation were sought for a coal slurry pipeline right-of-way, it would be under the broad provisions of statutes that do not specifically mention slurry lines as an authorized use. These condemnation actions would be subject to litigation delays as the applicability of the statutes is tested in the courts. There can be no certain answer as to the result of these actions if a challenge were mounted. Therefore, it is best that plans for a coal slurry pipeline avoid the necessity of condemnation through private negotiation. The experience of the Black Mesa Pipeline is evidence that a slurry can be constructed without resort to eminent domain.

Outlook for Coal Slurry Pipeline Rights-of-Way. Except for the doubts raised over the availability of eminent domain for slurry pipelines, authority exists under which rights-of-way for the project could be acquired. But there are two major obstacles that could either delay commencement of construction for a number of years or effectively halt the project.

The first impediment is the inherent potential for administrative delay in receiving federal permits, due to both the complexity of conforming with the terms of the National Environmental Policy Act (NEPA),[91] and the general disarray of federal coal policy. While rights-of-way applications filed with BLM for small projects may be acted upon within one year,[92] the approval process becomes much more complex for larger projects and when several federal agencies and states are involved. Separate applications must be filed with BLM for crossing public lands,[92] and with the director of any national park or national forest to be crossed by a pipeline. In addition, BLM, with which most of the applications for this project would have to be filed, deals with applications through state offices, creating yet another layer of possible administrative delays.[92] Where a project involves lands located predominantly in one state, it is common practice for the BLM directors of the other affected states to defer decision-making to the director in the state primarily affected. The amount of coordination and deference seems to be highly discretionary, depending upon the size of the project and the length of the right-of-way involved.[92] The state offices, in turn, depend upon regional directors within the state to handle the preparation of the environmental impact statements,[93] which involve public hearings on the proposed project. For large projects such as the one proposed in this report, the office of the Secretary of the Interior in Washington, DC, would likely become involved and make the final decision. Although some coordination among federal agencies is likely, normal insistence upon prerogatives will result in overlapping procedures and delays when a consensus is sought for permit issuance.

Where national forests, parks, or wildlife refuges are to be crossed, the supervisor or director charged with granting rights-of-way may be constrained by specific requirements[94] or be faced with different policy considerations regarding the intended purpose of the reserved lands. The uncertainty of permits being granted by BLM and the Department of the Interior in the near future would be further reduced by pending changes in that Department's coal policy.[95]

Nevada Power Company is presently awaiting action on permit applications that were filed in early 1974 for its proposed pipeline from Alton, Utah.[96] All permits involving the use of coal have been stalled pending the completion of a Regional Coal Analysis Impact Report currently being prepared under the direction of the US Geological Survey in Salt Lake City, Utah. Presumably, this study is tied to the consideration being given strip mining legislation now pending before Congress.[97] It is apparent that the general uncertainty over the direction of federal coal policy has the potential to stall any project using coal and requiring federal permits for a slurry line. Nevada Power does not expect action on its application until October 1978, at the earliest, which would mean that if the application is granted, service from the new plant could not begin until 1983.[97]

The second major problem facing the construction of a pipeline is the opposition of the railroads, which fear that pipeline competition will deprive them of profitable coal-hauling business. Their opposition is manifested in their refusals to sell easements to pipeline companies across railroad rights-of-way,[98] and by railroad lobbying efforts to prevent clarification of state eminent domain statutes or the adoption of a federal eminent domain right.[99] Railroad companies can also be expected to challenge the exercise of eminent domain under vague statutes or raise the issue of whether in-state public use is a prerequisite to condemnation in state court proceedings.[100]

Without action by state legislatures, the railroad position to obstruct the granting of new rights-of-way is very strong. However, where tracks are on a federally granted right-of-way across public lands, such a right is for that use only.[101] Accordingly, underpass or overpass permits may be acquired from federal authorities.[102] In addition, where development by rail is economically prohibitive due to formidable terrain, the potential to negotiate a right-of-way is improved.[103]

Legislation pending in the House Committee on Interior and Insular Affairs is intended to facilitate construction of coal slurry pipelines. The committee has been the focal point of intense lobbying by both the railroads and coal slurry companies. The four identical bills under consideration[104] would further amend the Federal Mineral Leasing Act of 1920 to include "coal" pipelines in the provisions for rights-of-way.[105] More important, the power of federal eminent domain would be granted when the pipeline cannot *otherwise* acquire land for a right-of-way. Under the bills' provisions, eminent domain cannot be exercised against any federal, state, or Indian lands, nor to obtain a right to use or develop water.

The Federal Rules of Civil Procedure (Rule 71A) will apply, and the condemnation proceeding will be held in the Federal District Court in which the land is situated. To exercise eminent domain, a carrier must be certified as a "public convenience and necessity" by the Secretary of the Interior, who must find that the pipeline project would be in the national interest. Such a finding could only be made after consultation with the Environmental Protection Agency, the Federal Energy Administration, and other appropriate federal, state, and local agencies. The Secretary of the Interior must weigh all relevant factors including (1) national needs, (2) the costs and benefits of alternative modes, (3) cost of delay, (4) disruption of the environment, and (5) the balance between water and energy needs.

While the federal power of eminent domain is considered essential by pipeline companies,[99] the procedures as presently formulated in the bills may well be so cumbersome as to raise serious doubts about whether construction would actually be more easily accommodated.[106]

In addition, the bills provide that such pipelines must be common carriers and subject to regulation by the Interstate Commerce Commission.[107]

The Committee has tabled this legislation, partly because of intense railroad lobbying, and also to await strip-mining legislation.[108] No further action is expected this session.[86] It should be noted, however, that even if legislation of this type were to pass Congress in the near future, it is highly unlikely that a coal slurry line could be constructed without difficulties and delays. This is true even with the availability of federal eminent domain. As indicated earlier, the cumbersome procedures themselves may frustrate construction.

3.4.3. Railroads. Although cost factors require that existing rail lines be used to the greatest extent possible, any site or coal source chosen would probably require additional spur tracks, and it is likely that longer lines would be needed to reach new mine sites. Since it appears unlikely that railroads would be permitted to cross national parks,[109] none of the proposed alternative routes for railroads crosses them. The legal issues for railroad right-of-way are thus confined to the availability of permits to cross public lands and the power of eminent domain condemnation proceedings if they should become necessary for the completion of the right-of-way.

Statutes on both the state and federal level generally confine the grants of permits of eminent domain power to railroad companies that are duly authorized or incorporated with all the regulations and common carrier requirements which such status entails. The Department of the Interior must therefore deal with existing railroad companies or incorporate a new company that would be subject to state and federal regulations. Where a contract is made with a railroad company to provide service from the mine to the power plant site, mechanisms exist by which the company can acquire the additional rights-of-way to provide the service.

In general, where a right-of-way is sought over nonreserved public land or privately owned land, it may be acquired fairly easily for railroads. Difficulty may arise if a route crosses Indian land, a national forest, or a state park. While mechanisms exist for obtaining rights across these lands, they are less certain to be granted.

Federal Lands. The General Right-of-Way Act of March 3, 1875, grants rights-of-way of up to 100 ft on either side of the central line of the road to railroad companies that are duly organized under the laws of the state or Federal Government.[110] In addition, the Secretary of the Interior retains the power to approve rights-of-way across any national forest "when, in his judgment, the public interests will not be injuriously affected thereby."[111] Under the applicable regulations, the right granted is not a fee title but an easement for the purposes granted, and for only so long as that use continues.[112] Rights-of-way granted under this part of the regulations are excepted from the payment of market value for the easement,[113] but where a national forest is to be crossed, the applicant must enter into such stipulations and must execute any bond which the Forest Service may require for the protection of the forest.[114]

For nonreserved public domain lands under the jurisdiction of BLM, the Department of the Interior has no power to deny a railroad right-of-way under the 1875 Act. Such a grant is subject only to the filing of maps, the proper applications, and the preparation of an environmental impact statement.[115] Experience shows that even with the delay in satisfying NEPA's procedural requirements, such rights-of-way can be acquired within one year.[115] Of course, a right-of-way across national forest land is granted on a discretionary basis, upon application to the Forest Service, and approval by the Secretary of Interior.[116] To the extent that new rights-of-way for railroads are confined to public domain lands, there will be little difficulty or delay for the railroad company to acquire such rights for this project.

Indian Lands. The Secretary of the Interior retains the authority to grant rights-of-way over land held in trust for the Indian tribes,[117] subject to the requirements that the Indian owners must give written consent and that full compensation must be paid.[118] As with other rights across the Indian land, the availability of an easement for a railroad, should one be necessary for the particular route chosen, will depend primarily upon the success of negotiations with the Indian owners.

State Statutes. For the remaining nonfederal land that would be crossed in various states, where rights-of-way cannot be purchased in private negotiations, eminent domain will once again be a necessary tool to complete a rail line. The power to exercise eminent domain is granted to railroad companies by all states that might be affected by this project.[119] Each state, of course, will have its own procedures, regulations, and requirements for certification to operate the railroad within its boundaries. In Utah, the State Land Board can grant rights-of-way across any state lands,[120] including a state park.

3.4.4. Transmission Lines. The proposals in this report vary in terms of their need for new transmission line rights-of-way. Where massive new development tied to coal production is involved, the same delays discussed above in connection with coal slurry pipelines can be expected. Since the Federal Government has begun to express some concern about using parallel rights-of-way, or so-called transmission corridors, legal problems will be diminished wherever such paralleling of lines is possible. There is also a possibility that the DWR might contract with another power company to share transmission lines serving the site areas. Such arrangements would considerably reduce the need to acquire additional rights-of-way. However, where new rights-of-way for transmission lines must be obtained, the federal and state legal mechanisms for acquiring such rights are clearly established, in contrast to the uncertainty surrounding coal slurry pipelines.

Federal Lands. There are two statutory authorities under which rights-of-way for electrical transmission lines may be obtained. The first is the Act of February 15, 1901, which allows the Secretary of the Interior to permit the use of rights-of-way—not to exceed 50 ft on either side of lines—for enumerated purposes, including electrical lines.[121] This is the same general statute under which rights-of-way for slurry pipelines are presently sought. Consequently, the same division of jurisdiction over various reserved and nonreserved lands within the Department of the Interior will be encountered. Where national forests are to be crossed, applications will have to be submitted to the Forest Service of the Department of Agriculture.[122]

The second statutory authority under which applications are generally submitted[123] is the Act of March 4, 1911,[124] which provides that the head of the department having jurisdiction over lands is authorized to grant rights-of-way for a period not exceeding 50 yr.

These rights-of-way may extend up to 200 ft on each side of the lines.[125] Applications are submitted separately to the Bureau of Land Management, the National Parks Service,[126] and the Forest Service[127] under the terms of the statute and the applicable regulations. The granting of these rights-of-way is again discretionary,[128] with considerable attention given to the environmental impact report submitted and the requirement that construction be consistent with the "Environmental Criteria for Electric Transmission Lines," prescribed jointly by the Secretaries of the Interior and of Agriculture.[129] Under the regulations of the Department of the Interior, the application may be approved "if the beneficial purposes and effects of the project will not be outweighed by an adverse environmental impact."[129] For those agencies of the Department that administer the reserved lands, the statute requires a finding that the project not be adverse to the public interest.[130]

For applications to cross national forests, the regulations provide that easement permits shall include any conditions necessary "for the protection of the public interests, and for the administration, protection, development and utilization of the National Forest."[131] These considerations, in addition to assessment of the environmental impact, make the granting of a right-of-way a matter of even greater discretion. Because this project will involve numerous types of permits and leases from the Federal Government, consideration would likely be given to the impact of the entire project, with approval based upon a regional environmental impact analysis.[132]

The cost of transmission line rights-of-way across national forests will be "reasonable annual charges" specified by the Chief of the Forest Service.[133] The cost of rights-of-way across BLM public lands or national parks is the fair market value of the easement as determined by Department of the Interior appraisal.[134] In addition, rights-of-way granted for electric transmission through any public land are subject to "wheeling" rights (see Sec. 3.3.3) of the Department of the Interior to use excess capacity.[135]

Indian Lands. Rights-of-way across Indian lands are obtained through the Secretary of the Interior under the general provisions discussed above.[136] Written approval of the Indian owners is required,[137] so negotiations for the right could be a major obstacle. Fair market value, severance, and incidental damages would be paid under the regulations governing such rights-of-way.[138]

State Lands. Subject to the problems that have been discussed regarding the exercise of the power of eminent domain in other states for a project that produces its principal benefit in California,[47-58] electric transmission lines are recognized as public uses for which eminent domain may be used in Utah,[139] Nevada,[140] Arizona,[141] and California.[142]

3.4.5. Prospects for Change in Federal Rights-of-Way Statutes. The statutory authority by which rights-of-way would be granted over the public lands is subject to drastic alteration under separate bills that have passed the House and Senate and that are currently in conference. Both the House bill, H. R. 13777 (passed July 22, 1976), and the Senate bill, S. 507 (passed in February 1977), purport to be a comprehensive streamlining of existing public land law. Each bill contains new provisions for the granting of rights-of-way across federal lands, replacing many of the statutory provisions previously discussed. The primary difference between the House and Senate versions is that the former includes the National Forest System within its provisions, while the Senate version deals merely with lands under the jurisdiction of the Secretary of the Interior. Because national forests are not included in what S. 507 terms the "national resource lands," it appears that applications for rights-of-way across national forests would continue to be made under the existing statutory authority. Because the House bill includes numerous provisions affecting the administration of the national forests with respect to grazing and minerals, the issue of whether the Department of Agriculture will be included in certain provisions of the compromise bill will be resolved in a conference scheduled to begin September 15, 1977. It is unclear at this time (1977) what form the final version will take.

Each bill includes three major provisions that would affect the proposed DWR project. First, a comprehensive list of uses for which rights-of-way may be granted specifically includes "pipelines, slurry and emulsion systems, conveyor belts for transportation and distribution of solid materials," railroads, and "systems for transmission and distribution of electrical energy." Thus, if this legislation is passed, all of the applications for rights-of-way for the project across public lands would be made under the same statutory authority. Second, with the policy objective of minimizing adverse environmental impact from the proliferation of separate rights-of-way, the bills provide that the Secretary of the Interior shall designate transportation and utility corridors, and to the extent practical, require that rights-of-way granted be confined to these corridors. The Secretary is required to issue regulations containing the criteria and procedures he will use to designate such corridors, and is given broad guidelines for determining whether the rights-of-way will be confined to the corridors. Third, like other old right-of-way statutes, the 1875 General Right of Way Act for Railroads would be repealed. All railroad right-of-way grants would then be subject to the discretionary authority of the Secretary of the Interior and would be treated like other rights-of-way, rather than receiving automatic approval upon application under present laws.

In deference to the policy goals of protecting the public interest in the resource lands and sound long-term management, the Secretary is given wide discretion to set the conditions and stipulations of the right-of-way grant necessary to carry out the purposes of the act. The Secretary is authorized to grant a right-of-way only when satisfied that "the applicant has the technical and financial capability to construct the project for which the right-of-way is requested, and in accord with the requirements" and stipulations of the grant. As a practical matter, the bills seem to clarify, rather than significantly alter, the considerations upon which rights-of-way decisions are made at present. But it is clear that environmental impact and the attempt to route rights-of-way in corridors will be of primary importance.

Each bill gives the Secretary discretion in setting the width of the right-of-way, based upon the nature of the project and the adverse environmental impact. Likewise, the bills differ from existing statutes in that the duration of the right-of-way is left to the determination of the Secretary, and the House version provides that the Secretary shall specify whether it shall be renewed. Fair market value must be paid, along with reasonable administrative costs in processing the application. Where a new project will have a significant environmental impact, the Secretary shall require that the applicant submit a plan of construction, operation, and rehabilitation that will comply with the terms and conditions of the grant, and may, at his discretion, require a bond to secure all of the obligations of the conditions.

Subject to environmental stipulations that will be applied to the grant and to the delays associated with the environmental impact assessments required under existing regulations for a project of the size proposed, it appears that the new bill would significantly reduce legal confusion with respect to coal slurry pipeline rights-of-way. It would also clarify the environmental and public interest criteria, which would form the basis for any decision by the Bureau of Land Management. The tone of the criteria expressed in the two bills, however, makes it clear that decisions on rights-of-way will not be made in a vacuum, so that coal policy, resource management, environmental quality, and the national interest will be important. There is no way to accurately predict how such decision will be reached until all the environmental, cost, and construction data are provided to the Bureau, and the regional impact studies have been completed.

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22. Most US railroads have grades up to 2.5% (130 ft per mile), but at grades exceeding 1% (52 ft per mile), train speeds and loads must be reduced. See *The Need For A National System of Transportation and Utility Corridors*, US Department of the Interior (1975), p. IV-20.

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39. Flashovers are often temporary. If the power to the line is temporarily disconnected the flashover will cease. When the circuit is reconnected it will function normally.

40. Data taken from Federal Power Commission, "National Power Survey " (1964). Relationship holds for a line composed of three aluminum cable, steel-reinforced conductors, each having a cross-sectional area of 954 million circular mills (an industry measurement unit).

41. Ref. 35, p. 12.

42. The value of 7.2 MW per 100 miles for the dc transmission line was computed by assuming an 0.023 ohm/mile line resistance and transmission of 1000 MW at 800 kV. The line

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43. "The Transmission of Electric Power," Federal Power Commission (Washington: US Government Printing Office), p. 99 (1971).

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45. Existing lines may become available for wheeling if a proposed transmission corridor between Los Angeles and San Onofre is approved.

46. Charles E. Olson, "Cost Considerations for Efficient Electric Supply," Institute of Public Utilities, Michigan State University (1970).

47. Eminent domain may also be an important tool for the acquisition of a plant site and water rights. The problems discussed in this section apply to those areas as well.

48. CAL. WATER CODE 250 (1976 Supp.).

49. P. Nichols. *The Law of Eminent Domain*, §211(2) (3rd Ed. 1975).

50. Ibid., at §2.112(3).

51. Ibid. at §2.111(1); Kohl vs United States, 91 U. S. 367, 373 (1875); Grover Irrigation Co. vs Lovella Ditch Co., 21 WYO. 204, 131 p. 143 (1913); *see* also Annotation 90 ALR 1032 (1934).

52. P. Nichols, *supra* note 3 at §2.12(3).

53. Grover vs Lovella, *supra* Ref. 51 at 245.

54. Shedd vs State Line Generating Co., 41 F. 2d 505, 507 (7th Cir. 1930); Carnegie Natural Gas Co. vs Swiger, 72 W. VA. 557, 79 S. E. 3 (1913).

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56. Telephone interview with Thomas Gilroy, Counsel, Southern Cal. Edison, August 6, 1976.

57. Ibid., telephone conversation, Valerie Scott, Counsel, Union Pacific Railroad, September 1, 1976.

58. Telephone interview with Thomas Gilroy, *supra* Ref. 56.

59. 31 Stat. 73 (1901), 43 U.S.C.A. §5 (1974).

60. Telephone interview with John Arledge, Asst. to the Vice President, Nevada Power Company, August 11, 1976.

61. *Hearings before the Committee on Interior and Insular Affairs on H. R. 1863, H. R. 2220, H. R. 2553, and H. R. 2986 to Amend the Mineral Leasing Act of 1920* at 129, 94th Cong., 1st Sess. (1975) (Statement of Jack O. Horton, Assistant Secretary, Department of Interior) (Hereafter cited as *Hearings*).

62. 43 C.F.R. §2801.1 (1975).

63. 16 U.S.C.A. §522; 36 C. F. R. §250 *et seq.* (1975).

64. 43 C.F.R. §2802.1-7(a) (1975).

65. 36 C.F.R. §251.57 (1975).

66. 43 C.F.R. §2801.1-1 (1975).

67. 30 U.S.C.A. §185 (Supp. 1976). Proposed legislation to include coal slurries under this Act are discussed in the text.

68. See text accompanying Ref. 86 and 105-109, *infra*.

69. 25 U.S.C.A. §324 (1963).

70. *Hearings, supra* Ref. 61 at 133; 25 C.F.R. §161 (1975).

71. 25 C.F.R. §161.3 (1975).

72. 25 C.F.R. §161.12 (1975).

73. 25 C.F.R. §161.13 (1975).

74. The issue of showing a public use within the state which authorizes condemnation is discussed in text accompanying Refs. 47-58 *supra*.

75. See text accompanying Ref. 76 *et seq. infra*.

76. CAL. CODE CIV. PROC. §1240.010 (Supp. 1976).

77. CAL. PUB. UTIL. CODE §227 (1975).

78. CAL. PUB. UTIL. CODE §615 (1975).

79. CAL. WATER CODE §250 (Supp. 1976).

80. NEV. REV. STAT. §37.010 (1973).

81. NEV. REV. STAT. §704.020(3) (1973).

82. UTAH CODE ANN. §78-34-11 (Supp. 1975).

83. UTAH CODE ANN. §78-34-3 (1953).

84. UTAH CODE ANN. §78-34-3(5) (1953).

85. ARIZ. REV. STAT. §12-111(17) (1956).

86. Telephone interview with Paul Haerle, Counsel, Energy Transportation Systems, Inc., August 31, 1976.

87. COLO. REV. STAT. §38-4-102 (1973).

88. Telephone interview with Paul Haerle, *supra* Ref. 86.

89. WYO. STAT. §1-794 (1957).

90. N.M. STAT. ANN. §68-1-4 (1953).

91. 42 U.S.C.A. §§4321-4347 (1973).

92. Telephone interview with Harriet Sousby, Acting Chief, California State Office, BLM, August 3, 1976.

93. Telephone interview with M. Berg, Regional Director, Riverside Office, BLM, July 28, 1976.

94. 16 U.S.C. §273 (d) (1974) for example, mandates the granting of rights-of-way over Capitol Reef National Park unless it would have significant adverse effects on the administration of the park.

95. See Secs. 2.3.1. & 2.4.1 *supra*.

96. Telephone interview with David Barnaby, Nevada Power Company, August 6, 1976.

97. Telephone interview with John Arledge, *supra* Ref. 60.

98. For example, the refusal by several railroad companies to grant rights-of-way is holding up a proposed Wyoming-Arkansas pipeline to be built by Energy Transportations Systems, Inc., which must cross tracks over 40 times along its proposed route.

99. Telephone interview with John Huneke, Vice President, Energy Transportation Systems, Inc., July 21, 1976.

100. Telephone interview with Paul Haerle, *supra* Ref. 86.

101. 43 C.F.R. §2842.1(a) (1975).

102. Telephone interview with John Arledge, *supra* Ref. 60. The availability of these permits to the Nevada Power Company Project, which would cross railroad lines only in two places, both on federal land, means that eminent domain action can be avoided.

103. This was another contributing factor in the grant of a right-of-way by Santa Fe Railroad to the Black Mesa Pipeline.

104. H. R. 1863; H. R. 2220; H. R. 2553; H. R. 2986, 94th Cong., 1st Sess. (1975).

105. 30 U.S.C.A. §185 (Supp. 1976).

106. *Id.*; *Hearings, supra* Ref. 61 at 629 (Statement of George M. Stafford, Chairman, Interstate Commerce Commission).

107. For a discussion of these issues, see material submitted by Paul Haerle in *Hearings, supra* Ref. 61, at 806-809.

108. Telephone interview with John Huneke, *supra* Ref. 99.

109. No general statutory authority exists for railroad rights-of-way across national parks, and it is unclear whether the provisions for Capitol Reef National Park, 16 U.S.C.A. §273 (d)(b) or Glen Canyon National Recreation Area, 16 USC 460 (dd)-6, which in nearly identical fashion provide that rights-of-way will be granted unless there would be significant adverse effects on the administration of the park, would allow grants to railroads, or whether it was intended to facilitate grants of rights for other purposes due to the elongated shape of the park.

110. 18 STAT 482 (1875), 43 U.S.C.A. §934 (1964).

111. 30 STAT 1233 (1899), 16 U.S.C.A. §525 (1974).

112. 43 C.F.R. §2842.1(a) (1975).

113. 43 C.F.R. §2802.1-7(c)(2) (1975).

114. 43 C.F.R. §2842.2-1(a) (1975).

115. Telephone interview, Valerie Scott, Counsel, Union Pacific Railroad, September 1, 1976.

116. 43 C.F.R. §2842.2-1 (1975).

117. 25 U.S.C.A. §312 (1963).

118. 25 U.S.C.A. §314 (1963) 25 C.F.R. §§161.12, 161.13, 161.23.

119. ARIZ. REV. STAT. §12-1111(8) (1956); CAL. PUB. UTIL. CODE §611 (1975); COLO. REV. STAT §38-2-101 (1973); NEV. REV. STAT. §37.010(4) (1973); N. M. STAT. ANN. §22-91 (1953); UTAH CODE ANN. §78-34-1 (1953); WYOMING STAT. §1-754 (1957).

120. UTAH CODE ANN. §65-2-1 (1953).

121. 31 STAT. 790 (1901), 43 U.S.C. §959 (1964).

122. 43 C.F.R. §2851.2-1(b)(1) (1975).

123. Telephone interview with Harriet Sousby, Acting Chief, California State Office, BLM, August 3, 1976.

124. 36 STAT. 1253 (1911).

125. But 43 C.F.R. §2851.2-1(c)(3) (1975), provides that rights will be limited to 50 ft on each side unless sufficient justification for additional width is shown.

126. 16 U.S.C.A. §5 (1974).

127. 16 U.S.C.A. §523 (1974).

128. 43 C.F.R. §2851.2-1 (1975).

129. 43 C.F.R. §2851.2-1(c)(6) (1975).

130. 16 U.S.C.A. §§5,523 (1974).

131. 36 C.F.R. §251.52(a) (1975).

132. C. F. Natural Resources Defense Council vs Butz, 6 Env. R. Cas. 1895 (D. D. C. 1974).

133. 36 C.F.R. §251.57 (1975).

134. 43 C.F.R. §2802.1-7 (1975).

135. Utah Power and Light Co. vs Morton, 504 F. 2d 728 (9th Cir. 1974); 36 C.F.R. §251.52(d)(2) (1975); 43 C.F.R. 2851.1-1(5) (1975).

136. 25 U.S.C.A. §323 (1963).

137. 25 U.S.C.A. §§324 (1963) 25 C.F.R. §161.3 (1975).

138. 25 C.F.R. §161.12-13 (1975).

139. UTAH CODE ANN. §78-34-1(8) (1953).

140. NEV. REV. STAT. §37.010 (1973).

141. ARIZ. REV. STAT §12-1111 (1956).

142. CAL. PUB. UTIL. CODE §§217, 612 (1975).

4. COST ANALYSIS

In this section we estimate the cost of mining and transporting coal-derived energy from mines to the sites. Many models are proposed for this purpose.

The word model means (1) a conceptual framework for identifying, computing, analyzing, and comparing costs; or (2) a computer program to handle the extensive computation necessary for cost analyses. The computer model was used to compare a large number of options.

In the DWR report the computer model was set up to identify nine major cost categories: (1) the cost of a power plant, (2) coal mining, (3) rail transportation, (4) slurry pipeline transportation, (5) water supply and treatment, (6) waste disposal, (7) air pollution control, (8) cooling, and (9) electric transmission.

Figure 4-1 is a diagram of the overall model used in the DWR study. Dashed lines represent information inputs and solid lines indicate resulting costs.

In this report, only four of the submodels shown in Fig. 4-1 will be presented: the coal supply model, the rail transport model, the slurry pipeline model, and the electric transmission model.

There are at least three other ways of classifying the costs of a coal-fired power plant project. First, we distinguish between "hard" and "soft" costs. The former are all those to which a reasonably reliable dollar cost can be ascribed. Soft costs are those which cannot be easily quantified, if at all; they include environmental impacts, legal constraints, and political problems. We have not attempted to quantify soft costs.

Another way of differentiating costs—both hard and soft—is according to whether they are site-independent or site-specific, "site" meaning either a coalfield or a power plant location. Site-dependent costs include, among others, transportation, coal mining, and electric power transmission.

Finally, costs may be one-time or repetitive. All costs in this report are expressed on an annual basis, either in January 1, 1977, dollars per year ($/yr) or in mills per kilowatt-hour (mills/kWh). The latter is determined by dividing the former by the annual energy production requirement, 7×10^9 kWh/yr, and multiplying by 1000 mills/dollar.

Fixed, or capital, costs are converted to annual costs in two ways. First, the annual cost of borrowing money is calculated by multiplying the capital cost by a "capital recovery factor (CRF)," defined by Eq. (4-1).

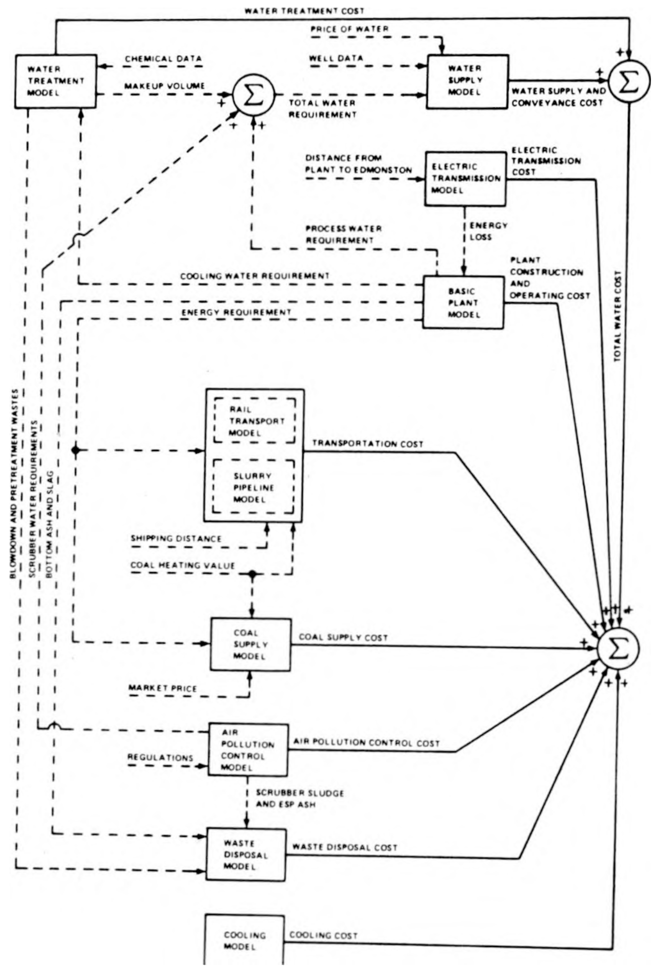

Fig. 4-1.
System cost estimation model.

$$\mathrm{CRF} = \frac{\mathrm{RINT} * (1 + \mathrm{RINT})**\mathrm{YRS}}{(1 + \mathrm{RINT})**\mathrm{YRS} - 1} , \qquad (4\text{-}1)$$

where RINT is the interest rate on borrowed money and YRS is the plant life in years.[1,2] As instructed by the DWR,[3] we have used RINT = 7.0% and YRS = 35 yr.

Second, capital costs are multiplied in all analyses by a "fixed charge rate (FCR)," which accounts for taxes, insurance, depreciation, and other costs associated with capital value.[4] As will be explained in Sec. 4.3, we used an FCR of 3.0%.

Finally, annual operating costs are added to the capital-based annual charges to obtain the total annual cost.

$$\text{Total annual cost} = \text{Capital cost} * (\text{FCR} + \text{CRF}) + \text{Operating cost} \ . \quad (4\text{-}2)$$

Factors for "inflating" costs from the year in which they are known to January 1, 1977, are shown in Table 4-1. They are based upon Gross National Product (GNP) implicit price deflators and construction cost indexes as reported by the Department of Commerce.[5] To find the January 1, 1977, value of a previous year cost, multiply the latter by the factor corresponding to that previous year.

4.1. Cost Estimating Procedures

4.1.1. Coal Mining. Coal mining costs were estimated by determining the production costs for underground and surface mining operations and comparing the results with actual prices of coal mined in the Western United States. Note that recently passed and pending state and federal coal legislation may have a pronounced effect upon coal prices in ways that this model cannot predict. In addition, the contract price the DWR will ultimately pay will be the result of complex negotiations with the owner or lessee of the coal source. The terms of such a contract are impossible to predict at the present time.

TABLE 4-1

INFLATION FACTORS FOR CONSTRUCTION AND OPERATING COSTS

	Inflation Factor for Calendar Year				
Cost Category	**1972**	**1973**	**1974**	**1975**	**1976**
Construction	1.40	1.29	1.22	1.12	1.00
Operating	1.34	1.27	1.16	1.06	1.00

Source: Ref. 5.

The following cost analysis is based upon these assumptions.

(1) The mine will be, where appropriate, surface (strip mines) or underground, using continuous mining equipment where feasible.
(2) The average coal seam will be 6 ft thick.
(3) Annual production will be 3 to 4 Mton.
(4) Coal preparation costs are not included.

Our main cost information source was the Coal Task Force report for the Federal Energy Administration's *Project Independence Blueprint*.[6] Table 4-2 shows a cost breakdown for the mining types considered here. Note that the costs were computed with the assumption of a 15% return on investment, discounted after taxes, over a 20-yr mine life. Such an assumption does not necessarily apply to a captive mine, but the data in Table 4-2 are the best available.

Capital Cost Estimation. The present value of the capital investment reported in Table 4-2 represents the costs of construction, engineering, and other preconstruction activities, credit for mining during development, land, interest during development, working capital, and contingencies.

According to line 3 of Table 4-2, the annual capital cost of an underground mine is

$$\text{CCC1 (\$/yr)} = 31\ 474\ 000 * 1.22 * \text{CRF} = 38\ 398\ 280 * \text{CRF} \ . \quad (4\text{-}3)$$

We have adjusted 1974 costs to 1977 dollars by multiplying them by the appropriate inflation factor from Table 4-1.

The surface mining cost estimates reported in Table 4-2 are based upon an 18:1 overburden ratio.[7] Analysis of mining cost data revealed a linear relationship among both capital and operating costs and overburden ratio, as seen in Fig. 4-2. To find the overburden-cost curves for a nominal 3-Mton-per-year (MTPY) operation, we interpolated between the 1 and 5 MTPY curves. Equations (4-4) and (4-7) are the results. Capital costs are found from

$$\text{Surface mine capital cost} = (2.95 \times 10^6 * B + 13.5 \times 10^6) * 1.22 \ , \quad (4\text{-}4)$$

TABLE 4-2

SUMMARY OF COSTS FOR UNDERGROUND AND SURFACE COAL MINING
(Costs in Thousands of Dollars)

Line	Mine Type: Underground	Mine Type: Surface	Reference Notes
Overburden ratio	---	18:1	7
1. Initial Capital	26 474	60 912	
2. Deferred Capital	20 783	10 436	
3. Present Value, Capital Investment	31 474	63 237	
4. Cash Flow	5 029	10 103	8
5. Sales	25 561	24 995	9
6. Operating Costs	21 554	13 965	
7. Gross Profit	4 007	11 029	10
8. Depletion	2 004	2 500	11
9. Profit Before Tax	2 003	8 530	12
10. Federal Income Tax	1 002	4 265	13
11. Net Profit	1 002	4 265	
Selling Price ($/Ton)	8.52	8.33	
Operating Cost			
12. Labor	6 529	2 686	14
13. Operating Supplies	5 370	2 000	
14. Power	750	1 050	
15. Payroll Overhead	2 885	940	15
16. Union Welfare	2 400	1 200	
17. Royalty	---	600	
18. Strip License and Reclamation Fund	---	300	
19. Indirect Cost	1 785	703	16
20. Taxes and Insurance	411	1 148	
21. Depreciation	2 023	3 339	17
22. Total	21 554	13 965	

where B is the overburden ratio (dimensionless) and 1.22 is the appropriate inflation factor. Since we assume a 6:1 ratio, the annual capital cost for strip mining is

$$\text{CCC2 (\$/yr)} = 38\ 064\ 000 * \text{CRF} . \qquad (4\text{-}5)$$

Operating Cost Estimation. Operating costs for underground mining are found by summing lines 12 through 19 in Table 4-2, since taxes, insurance, and depreciation are accounted for in the fixed charge rate. The summed costs are multiplied by an inflation factor of 1.16, as indicated by Table 4-1. We assume that operating costs will vary with the ratio of actual coal production to the nominal 3 MTPY rate, upon which the data in Table 4-2 are based. The annual operating cost for an underground mine is

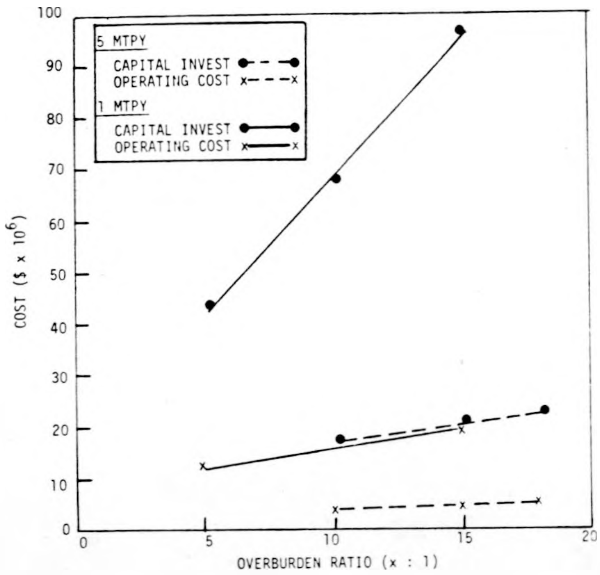

Fig. 4-2.
Coal mining capital and operating costs as a function of overburden ratio.

$$\text{COC1 (\$/yr)} = 38\ 398\ 280 * \text{FCR} + 22\ 874\ 040 * (\text{TPY}/3 \times 10^6) \ , \tag{4-6}$$

where TPY is the actual coal production in tons/year (see Sec. 4.1.2). This equation simplifies to

$$\text{COC1} = 38\ 398\ 280 * \text{FCR} + 7.625 * \text{TPY} \ . \tag{4-7}$$

The operating cost for a 3-MTPY surface mine is found by interpolation in Fig. 4-2.

$$\text{Surface mine operating cost} = [(400\ 000 * B + 5.5 \times 10^6) * 1.16] * (\text{TPY}/3 \times 10^6) \ . \tag{4-8}$$

For a 6:1 overburden ratio then, the surface mine operating cost is

$$\text{COC2} + 38\ 064\ 000 * \text{FCR} + 3.055 * \text{TPY} \ . \tag{4-9}$$

Total Mining Costs. The total mining costs are found by summing capital and operating costs. For underground and surface mining, respectively,

$$\text{CTC1 (\$/yr)} = 38\ 398\ 280 * (\text{CRF} + \text{FCR}) + 7.625 * \text{TPY} \ . \tag{4-10}$$

$$\text{CTC2 (\$/yr)} = 38\ 064\ 000 * (\text{CRF} + \text{FCR}) + 3.055 * \text{TPY} \ . \tag{4-11}$$

In the computer model, only one mining type is applicable to each coalfield. Table 4-3 shows the coal costs that would result from application of Eqs. (4-10) and (4-11) to various production rates between 2.5 and 3.5 tons/yr. The results for surface mines compare favorably with actual coal prices, as reported in Table 4-4.

Predicted underground mining costs, on the other hand, are 15 to 35% below actual market prices. The discrepancy may be due to incorrect assumptions in the Federal Energy Administration estimate, to more rapid inflation in the mining industry than in the economy as a whole, or to local geological problems. We decided to normalize the predicted costs to the actual price of 3 MTPY at the Book Cliffs and Wasatch Plateau coalfields. The factor CF1 (10/9) adjusts CTC1 to $10/ton for those coalfields. CF2 then increases CTC1 by the ratio between the price for a given coalfield and the price for Book Cliffs or Wasatch coal; we assume that these price differentials reflect degrees of difficulty of mining. Values of CF2 are shown in Table 4-4. The final total underground mining cost becomes

$$\text{CTC1} = [38\ 398\ 280 * (\text{CRF} + \text{FCR}) + 7.625 * \text{TPY}] * \text{CF1} * \text{CF2} \ . \tag{4-12}$$

4.1.2. Rail Transportation. This portion of the model determines the cost to the DWR of shipping coal by unit train between prospective coalfields and power plant sites, assuming that the State of California will own rolling stock and loading and unloading facilities and will bear the cost of any necessary rail construction. To the extent permitted by the available data, we have estimated costs by identifying all constituent cost elements and the costs thereof. If the DWR contracts with a private railroad company for coal shipment, the actual tariffs charged could be somewhat higher, though not necessarily so. We did not attempt to predict the

TABLE 4-3

COAL COSTS PREDICTED BY MODEL

Production	Underground		Surface	
(tons/yr × 10^6)	($/ton)	($/mmBtu)[a]	($/ton)	($/mmBtu)[a]
2.5	9.27	0.386	4.69	0.234
2.6	9.21	0.384	4.62	0.231
2.7	9.15	0.381	4.57	0.228
2.8	9.10	0.379	4.51	0.226
2.9	9.04	0.377	4.46	0.223
3.0	9.00	0.375	4.41	0.221
3.1	8.95	0.373	4.37	0.219
3.2	8.91	0.371	4.33	0.216
3.3	8.87	0.370	4.29	0.215
3.4	8.84	0.368	4.25	0.213
3.5	8.80	0.367	4.22	0.211

[a]Cents per 10^6 Btu, assuming a heating value of 12 000 Btu/lb for underground and 10 000 Btu/lb for surface mines.

TABLE 4-4

ACTUAL OR EXTRAPOLATED WESTERN COAL COSTS, 1975

Underground Mine Area	Price[a] ($/ton)	CF2	Surface Mine Area	Price ($/ton)
Kaiparowits	11.00	1.10	Alton	5.00
Book Cliffs	10.00	1.00	Black Mesa	3.09
Wasatch	10.00	1.00	Gallup	6.00
Emery	12.00	1.20	Star Lake	4.50
Sego and Book Cliffs (Colorado)	12.00	1.20	Yampa	7.00
Somerset	14.00	1.40	Kemmerer	7.09
Grand Hogback and Carbondale	14.00	1.40	Rock Springs	4.55
Evanston	12.00	1.20	Great Divide and Little Snake River	5.00
			Hanna	5.00

[a]CF1 = 1.1111111.
(See Sec. 2.)

cost to the DWR if it shares the financing of a new coal-haul railroad with other public and private agencies.

In addition to predicting the rail cost component of the total project cost, the model determines the lowest cost route from the Alton and Kaiparowits coalfields to existing mainlines, given information on the new rail segments described in Sec. 3.1.3.

Capital Costs. The main elements of the capital costs of a coal unit train operation are diagrammed in Fig. 4-3. Capital costs may be divided between those for new construction (including tunnels and bridges) and those for capital equipment, which consists of rolling stock and coal-handling facilities.

New Construction. Since the costs of new track, bridges, tunnels, and other construction items depend upon local topography, geology, wage rates, and other variable factors, a general railroad cost model can provide only a reasonable estimate, which could differ considerably from an engineering estimate based upon a detailed survey of a particular route. The same unit cost assumptions were used for all alternative rail routes. As railroad companies and construction firms were reluctant to provide unit cost data for bridges and tunnels, we obtained the information from recent issues of the *Engineering News-Record*. We inflated the estimates, shown in Table 4-5, to mid-1976 dollars. Given the great diversity of unit costs, bridge types, and materials, we cannot reliably predict costs of bridges and tunnels for an actual coal railroad. The unit bridge cost and unit tunnel cost, which are listed in Table 4-6, were set conservatively at the lower end of the reported ranges.

New tract construction over "average" terrain was estimated at $1 million per mile.[32] To account for the higher cost of construction in rough or very rough terrain—as judged from examination of topographic maps for specific routes—the new construction segment distances are multiplied by a factor whose value is 1.5 and 3.0, respectively; for average terrain, the factor is 1.0. The factor for a segment traversing more than one type of terrain is computed by weighting the corresponding distances by 1.0, 1.5, or 3.0. For example, if a segment traversed 10 miles of average, 8 miles of rough, and 2 miles of very rough terrain, the weighted factor would be

$$[10(1) + 8(1.5) + 2(3)]/20 = 1.4$$

In the computer model, the factor is called BUILD. If DIST is the length of the segment, the cost of new track (CNC) is

$$\text{CNC} = \text{DIST} * \text{BUILD} * 1\,000\,000 \ . \qquad (4\text{-}13)$$

If the combined cost of bridges and tunnels for an alternative railroad route is SPCON, then the total annual new construction capital cost is

$$\text{CNRR (\$/yr)} = (\text{SPCON} + \text{CNC}) * \text{CRF} \ . \qquad (4\text{-}14)$$

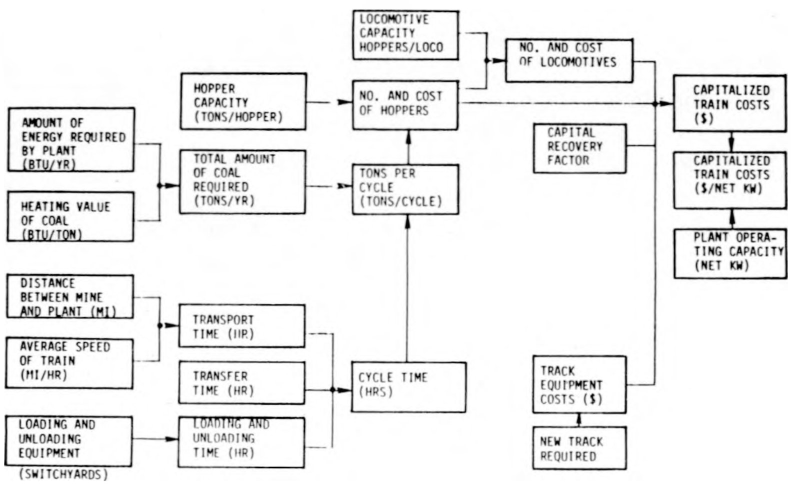

Fig. 4-3.
Rail transportation capital cost model.

TABLE 4-5

RECENT TUNNEL AND BRIDGE COSTS

Tunnels Location	Type	Length (ft)	Cost (1976 dollars)	Cost/mile ($ × 10^6)	Reference Notes
East River, New York	Rail	3 490	75 040 000	113	18
Hampton Roads, Virginia	Tube	6 900	101 840 000	78	18
New York	Subway	3 010	97 410 000	171	19
New York	?	4 000	41 660 000	55	20
Arizona	Aqueduct	35 900	65 920 000	10	21
Philadelphia	Rail	9 000	293 730 000	173	22
Colorado	Highway	9 200	124 352 000	71	23
Washington, DC	Transit	15 800	37 413 000	12	24

Bridges Crossing and State	Type	Main Span (ft)	Cost (1976-$)	Cost/mi ($ × 10^6)	Reference Notes
Cuyahoga River; Ohio[a]	Plate girder	300	32 160 000	541.7	25
Mississippi River; Illinois[b]	Cont. truss arch	821	26 800 000	172.4	25
Atchafalaya River; Louisiana[c]	Cantilever truss	60	12 312 000	1083.5	25
Patapsco River; Maryland[d]	Through truss	1 200	145 692 000	641.0	25
Pine Valley Creek; California[e]	Concr. box girder	450	10 260 000	120.4	25
Stanislaus River; California[f]	Steel box girder	550	14 364 000	137.9	25
Monongahela River; Pennsylvania[g]	Tied arch	620	19 494 000	166.0	25
Dumbarton River; California[h]	Concrete girder	250	71 820 000	1516.8	25
New River Gorge; West Virginia[i]	Steel arch	1 700	34 884 000	108.3	25
Mississippi River; Louisiana[j]	Steel stayed-girder	1 235	138 510 000	592.2	25
Tombigbee River; Alabama	Cont. weld. plate	975	6 002 100	32.5	26

TABLE 4-5 (cont)

Ohio River; West Virginia[k]	Steel tied arch	780	14 056 200	95.1	27
Columbia River; West Virginia[l]	Concr. stayed-girder	981	24 316 200	130.9	28
? West Virginia	Two-hinged arch	3 350	47 617 500	75.1	29
? Texas	Concr: and steel	1 400	3 193 200	12.0	30
Interstate Highway; Illinois	17-span steel	3 960	12 988 100	17.3	31

[a] Independence
[b] Cairo
[c] Morgan City
[d] Baltimore
[e] San Diego
[f] California Route 49
[g] Pittsburgh
[h] San Francisco Bay
[i] Fayetteville
[j] Luling
[k] Wheeling
[l] Pasco

TABLE 4-6

RAIL CONSTRUCTION COSTS USED IN THE MODEL

Item	Unit Cost
New rail	\$ 1 000 000/mile
Tunnel	\$10 000 000/mile
Bridge	\$12 000 000/mile
Cuts and fills	\$4/cubic foot

Capital Equipment. Capital equipment costs include those for locomotives, hoppers, and coal loading and unloading facilities. We shall first consider the annual volume of coal shipped, TPY (tons/yr), upon which all subsequent calculations depend. The power plant must produce 7×10^9 kWh of electrical energy per year. Although modern power plant thermal efficiencies are normally about 35 to 40%, air pollution control equipment exacts a 5 to 7% energy penalty. We therefore assumed 35% thermal efficiency. Since there are 3413 Btu/kWh, the energy input requirement would ordinarily be

$$\text{Annual plant energy input} = \frac{(7 \times 10^9\ \text{kWh/yr}) * (3413\ \text{Btu/kWh})}{0.35}$$

$$= 6.826 \times 10^{13}\ \text{Btu/yr}\ . \qquad (4\text{-}15)$$

More energy is required, however, to make up for electric transmission losses. Equations (4-46) through (4-48) in Sec. 4.1.4 relate the required plant capacity to the power plant-to-Edmonston electric transmission distance, ETP (miles). For cost estimation purposes, we will assume that this required increase in capacity can be expressed as an equivalent increase in energy output requirement; the latter would then require a proportionately larger energy input. This can be done by dividing

Eqs. (4-46) through (4-48) by 1000 (to normalize them to a 1000-MW power plant) and multiplying them by 6.826×10^{13} Btu/yr

$$\text{Energy requirement (Btu/yr) (ac transmission, ETP} < 275 \text{ mi)} = 6.944 \times 10^{13} + 9.72 \times 10^{9} * \text{ETP} . \quad (4\text{-}16)$$

$$\text{Energy requirement (Btu/yr) (ac transmission, ETP} > 275 \text{ mi)} = 6.944 \times 10^{13} + 6.25 \times 10^{9} * \text{ETP}. \quad (4\text{-}17)$$

$$\text{Energy requirement (Btu/yr) (dc transmission)} = 6.930 \times 10^{13} + 4.990 \times 10^{9} * \text{ETP} . \quad (4\text{-}18)$$

Let ER(Btu/yr) be the energy requirement calculated from one of the preceding three equations. Then, if the heating value of the coal used is HV(Btu/lb), the coal requirement is

$$\text{Coal requirement (tons/yr)} = \frac{\text{ER}}{\text{HV} * 2000 \text{ lb/ton}} . \quad (4\text{-}19)$$

About 0.1% of the total coal tonnage shipped by rail is lost by spillage in loading, unloading, and transit,[34] so the coal requirement must be increased by a factor of 1/0.999. The coal requirement is therefore

$$\text{TPY (tons/yr)} = \frac{5.005 \times 10^{-4} * \text{ER}}{\text{HV}} . \quad (4\text{-}20)$$

The following analysis of hopper car and locomotive requirements is, with some modifications, the methodology used by the Interagency Task Force in preparing the Federal Energy Administration's Project Independence Blueprint.[35] Similar methodologies have been used in other reports.[36,37] The time for one round trip, or cycle, of a unit train is the sum of the times for transit, transfer, loading, and unloading. It is also necessary to allow "for contingencies such as derailments, unexpected congestion, extraordinary maintenance and assorted acts of God."[38] Loading times for a 100-car coal train have been estimated at 4 to 5 h[36] and 5 to 6 h.[39] Unloading time estimates vary more widely—4 h to 1 day.[36] We shall adopt the Administration's upper bound estimate of 30 h for loading and unloading, plus 18 h for contingencies, making a total of 48 h of nonline haul activity. This total also includes times for switching rail lines, changing crews, and federal inspections. Although train speeds will vary greatly, especially over mountainous routes, we assume an average train speed of 25 mph loaded and 40 mph unloaded. If RAILD is the one-way distance in miles between mine and power plant site, then the time for one cycle is

$$\text{Days/cycle} = \frac{1}{24}\left(\frac{\text{RAILD}}{25} + \frac{\text{RAILD}}{40} + 48\right) . \quad (4\text{-}21)$$

$$\text{CPY(cycles/yr)} = \frac{24\,000 * 365}{65 * \text{RAILD} + 48\,000} . \quad (4\text{-}22)$$

For example, since the distance from Alton to Cadiz is 785 miles, the cycle time would be 4.13 days. There would thus be 88.5 coal shipments per year.

Peat, Marwick and Mitchell (PMM) have developed a formula to estimate the size of the hopper-car fleet necessary for unit train coal transportation. Renaming some of the variables to conform with the rest of this section, we have:[40]

$$\text{H} = \frac{\text{TPY}}{100 * \text{UTIL} * \text{CPY} * (1 - \text{BO})} , \quad (4\text{-}23)$$

where H = number of cars in the fleet, UTIL = ratio of average net load to average car capacity, and BO = fraction of cars out of service. To simplify analysis, we have assumed that the hopper fleet will consist entirely of brand new, 100-ton-net-capacity cars. PMM use a UTIL value of 0.98.[41] BO is difficult to estimate without detailed operating data. The Atchison, Topeka & Santa Fe Railroad schedules each hopper car on its York Canyon-Fontana run for two maintenance periods per year.[42] Assuming 2 days for maintenance, at any given time 4/365 cars, or about 11%, would be out of service. PMM estimate values between 0.03 and 0.05. For simplicity, we shall assume that BO = 0.10.

Combining Eqs. (4-22) and (4-23), we have

$$\text{H} = \frac{\text{TPY} * (65 * \text{RAILD} + 48\,000)}{7.73 \times 10^{8}} . \quad (4\text{-}24)$$

Using the above Alton-Cadiz example, and assuming a 3-Mton annual coal demand, we find that a 384-car hopper fleet would be necessary.

The cost of a hopper, if purchased today, is (HPCOST) = \$32 000.[43] The average working life of a coal hopper is 30 yr. For ease in calculation, we shall assume that hopper life can be "stretched" to 35 yr by better maintenance techniques. We also assume that all hoppers are purchased new, so that, on the average, 1/35 of the fleet must be replaced each year.

Because all cost calculations in this study are done on an annual basis, we need to know the present (time zero) worth of all future hopper purchases, known as the "uniform series present worth." If RINV is the return the State of California can perceive on its investments, and YRS is the project length in years, then the present worth of the initial fleet and all replacements is

$$\text{PWHOP (\$)} = \text{H} * 32\ 000$$

$$* \left[1 + \frac{1}{35} * \frac{(1 + \text{RINV})**\text{YRS} - 1}{\text{RINV} * (1 + \text{RINV})**\text{YRS}}\right] . \quad (4\text{-}25)$$

For example, if RINV = 0.10, then for the Alton-Cadiz case,

$$\text{PWHOP} = (384)(32\ 000)$$

$$\left[1 + \frac{(1.1)^{35} - 1}{(35)(0.1)(1.1)^{35}}\right] = \$15\ 673\ 927 .$$

At a 10% rate of return, the hopper fleet will cost about 28% more than if there were no replacements. Table 4-7 shows the per cent increase in cost at various rates of return.

TABLE 4-7

EFFECT OF RATE OF RETURN ON HOPPER FLEET COST

Rate of Return (%)	Increase in Fleet Cost (%)
8	33
10	28
12	23
15	19
20	14

PMM has also developed a formula for locomotive requirements.[44] Again, substituting our variable names, we have

$$\text{No. of locomotives (QLOC)} = \frac{\text{TPY} * \text{HPT} * 2 * \text{RAILD}}{\text{HPL} * \text{u} * \text{V} * 8760}, \quad (4\text{-}26)$$

where the new variables are HPT = hp per net ton; HPL = average hp per locomotive unit; u = per cent of average time locomotive unit is in service, expressed as a decimal; and 8760 = h per yr. Using HPT = 2 hp/net ton (see Sec. 3.1.1), HPL = 2400 hp,[45] u = 0.75[46] and V = (25 + 40)/2 = 32.5 mph, we have

$$\text{QLOC} = 7.805 \times 10^{-9} * \text{TPY} * \text{RAILD} . \quad (4\text{-}27)$$

Locomotives are assumed to last 35 yr without replacement and to cost \$400 000 each.[43] The cost of locomotives is therefore,

$$\text{CLOC (\$)} = 400\ 000 * \text{QLOC} . \quad (4\text{-}28)$$

A 1-Mton/yr loading facility costs \$3.5 million, and a 4-Mton/yr facility costs \$5.5 million.[60] If a linear relationship between tonnage and loading facility cost exists, it is

$$\text{Loading facility cost (\$)} = \frac{2 * \text{TPY} + 8\ 500\ 000}{3} . \quad (4\text{-}29)$$

A bottom dump unloading facility for a 1-Mton/yr costs \$12 million, while a 4-Mton/yr facility costs \$22 million.[60]

$$\text{Unloading facility cost (\$)} = \frac{10 * \text{TPY} + 26\ 000\ 000}{3} . \quad (4\text{-}30)$$

Adding Eqs. (4-29) and (4-30), we obtain the total cost of loading and unloading facilities

$$\text{CLUF (\$)} = 4 * \text{TPY} + 11\ 500\ 000 . \quad (4\text{-}31)$$

The annual capital equipment cost, CAPEQ (\$/yr), is then the sum of the capitalized costs of rolling stock and coal-handling facilities

$$\text{CAPEQ } (\$/\text{yr}) = (\text{PWHOP} + \text{CLOC} + \text{CLUF}) * \text{CRF} \ . \qquad (4\text{-}32)$$

Operating Costs. Operating costs (outlined in Fig. 4-4) include those for coal handling and unit train operation. Operating and maintenance costs for a 1-Mton/yr loading or unloading facility are $600 000 per yr, while those for a 4-Mton/yr facility would be $1.2 million.[60] A linear interpretation of these data would be

$$\text{Facilities operating cost } (\$/\text{yr}) = 0.2 * \text{TPY} + 400\,000 \ . \qquad (4\text{-}33)$$

A Bechtel Corporation study of western unit trains[47] fitted Eq. (4-34) to 1974 tariffs:

$$\text{Tariff(mills/ton-mile)} = 122.45 * \text{D}{**}(-0.391) \ , \qquad (4\text{-}34)$$

where D is the one-way haulage distance (miles). Note that this represents a round-trip tariff, since trains run empty on the return trip. The tariff would be composed of actual operating costs, annual capital costs, and profit. A Bureau of Mines study[48] estimates that a unit train hauling 25-Mton/yr of coal over 1000 miles would have operating costs of $110 million, or 4.4 mills/ton-mile. Using the 1975 operating cost inflation factor from Table 4-7, we can discount this cost to 4.02 mills/ton-mile in 1974. Since the tariff estimated by Eq. (4-34) is 8.22 mills/ton-mile,[49] the annual capital costs and profit are 8.22-4.02, or 4.20 mills/ton-mile. Differentially inflating each cost component by the corresponding inflation factors from Table 4-1, we have:

$$\text{Mid-1976 tariff(mills/ton-mile)} = 4.02 * 1.156 + 4.20 * 1.219 = 9.77 \text{ mills/ton-mile} \ .$$

The overall increase in tariffs would be 9.77/8.22, or 119%. Due to the differential inflation rates, January 1977 operating costs would represent 47.6% of the tariff. To adjust Eq. (4-34) to 1977 costs, we multiply it by 1.19, 0.476, and 10^{-3} to obtain CPM, the operating cost in dollars per ton-mile.

$$\text{CPM}(\$/\text{ton-mile}) = 0.0694 * \text{D}{**}(-0.391) \ . \qquad (4\text{-}35)$$

Using previously defined terms and letting UTOC be the unit train operating cost, we obtain

$$\text{UTOC } (\$/\text{yr}) = \text{CPM} * \text{TPY} * \text{RAILD} = 0.0694 * \text{TPY} * \text{RAILD}{**}(0.609) \ . \qquad (4\text{-}36)$$

The total annual operating cost would then be:

$$\text{OPCOST } (\$/\text{yr}) = (\text{SPCON} + \text{CNC} + \text{CAPEQ}) * \text{FCR} + 0.2 * \text{TPY} + 400\,000 + 0.694 * \text{TPY} * \text{RAILD}{**}(0.609) \ . \qquad (4\text{-}37)$$

Total Rail Transportation Cost. The total rail transportation cost is the sum of annual capital and operating costs:

$$\text{RRD } (\$/\text{yr}) = (\text{SPCON} + \text{CNC} + \text{CAPEQ}) * (\text{CRF} + \text{FCR}) + 0.2 * \text{TPY} + 400\,000 + 0.0694 * \text{TPY} * \text{RAILD}{**}(0.609) \ . \qquad (4\text{-}38)$$

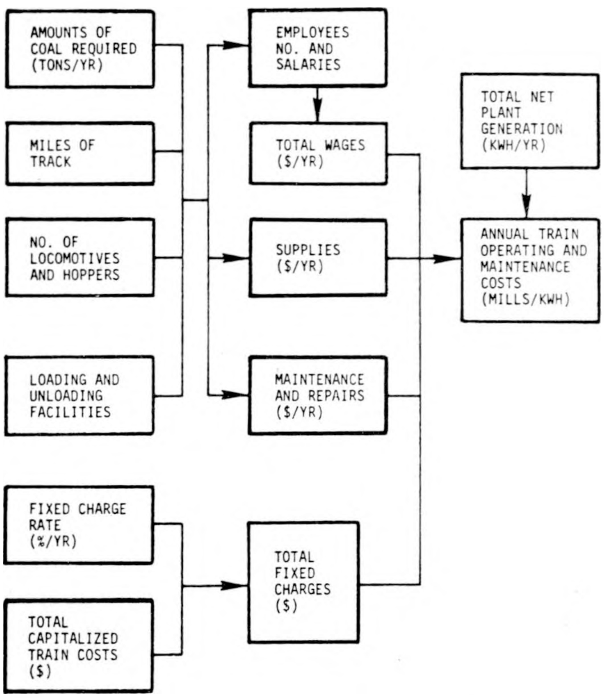

Fig. 4-4.
Rail transportation operating cost model.

For systems analysis purposes, we have combined Eqs. (4-16), (4-20), (4-24), (4-25), (4-27), (4-28), (4-34), and (4-37) to express RRD in terms of haulage distance and coal heating value, assuming 15 miles of new rail and 250 miles of ac electric transmission:

$$\text{RRD (\$/yr)} = 3.242 \times 10^6 + (3.239 \times 10^{10} + 2.528 \times 10^7 * \text{RAILD} + 2.496 \times 10^9 * \text{RAILD}^{**}0.609)/\text{HV} \ . \tag{4-39}$$

This equation is used in Secs. 4.2.2 and 4.3.

4.1.3. Coal Slurry Pipeline. Since there is only one coal slurry pipeline in operation, accurate cost estimation is difficult. This section is based primarily on data provided by Bechtel Corporation to the Transportation Task Force in the Project Independence Blueprint study.[35] The study presented a formula relating capital investment to pipeline distance and annual throughput. Letting PDIST be the pipeline length (miles), we have:[50]

$$\text{Annual capital cost (\$/yr)} = 21.7 \times 10^6 + 96\,700 * \text{PDIST} + 63.4 * \text{PDIST} * \text{TPY}^{**}0.5 \ . \tag{4-40}$$

The first term in Eq. (4-40) represents fixed costs, mostly for coal preparation facilities. The second term estimates route acquisition and preparation costs, which could vary widely with terrain, and the last represents the purchase and laying of pipe.[50] A capital recovery factor of 0.152, based on 15% interest over 30 yr, was assumed. Finally, the coefficient of the third term was scaled so that the equation fit Bechtel's estimate of $430 million for a 1000-mile, 25-MTPY pipeline.[51] After escalating Eq. (4-40) to 1977 dollars, we have the annual capital cost for a slurry pipeline, PLCC:

$$\text{PLCC (\$/yr)} = [26.5 \times 10^6 + \text{PDIST} * (118\,000 + 76.0 * \text{TPY}^{**}0.5)] * \text{CRF} \ . \tag{4-41}$$

The Project Independence study also proposed a formula for total annual cost:[52]

$$\text{Annual cost (\$/yr)} = 3.3 \times 10^6 + 1.93 * \text{TPY} + 14\,700 * \text{PDIST} + 11.4 * \text{PDIST} * \text{TPY}^{**}0.5 \ . \tag{4-42}$$

To determine the portion represented by the operating costs, we must subtract Eq. (4-41) from Eq. (4-42). Note, however, that for this subtraction we must use the CRF of 0.152 implicit in Eq. (4-40). At all other times, we use the same CRF as in the rest of the cost model. The operating cost (excluding fixed charges), escalated to 1977 dollars, is

$$\text{Operating cost (\$/yr)} = 2.23 * \text{TPY} + 2.22 * \text{PDIST} * \text{TPY}^{**}0.5 \ . \tag{4-43}$$

When fixed charges are included, the total annual operating cost, PLOC, is:

$$\text{PLOC (\$/yr)} = [26.5 \times 10^6 + \text{PDIST} * (118\,000 + 76.0 * \text{TPY}^{**}0.5)] * \text{FCR} + 2.23 * \text{TPY} + 2.22 * \text{PDIST} * \text{TPY}^{**}0.5 \ . \tag{4-44}$$

The total coal slurry pipeline annual cost is the sum of Eqs. (4-41) and (4-44).

$$\text{CPD (\$/yr)} = [26.5 \times 10^6 + \text{PDIST} * (18\,000 + 76.0 * \text{TPY}^{**}0.5)] * (\text{CRF} + \text{FCR}) + 2.23 * \text{TPY} + 2.22 * \text{PDIST} * \text{TPY}^{**}0.5 \ . \tag{4-45}$$

4.1.4. Electric Transmission. As noted in Sec. 3.3.3, ac transmission is generally cheaper than dc for relatively short distances. We cannot suboptimize in this cost category, however, because ac power losses exceed those for dc; it may be possible that an ac system would require a greater plant capacity and thus result in a higher total annual cost. Accordingly, the cost model compares the total project cost for the two alternatives before selecting the optimum transmission mode.

We assumed the following.

(1) For transmission distances under 275 miles, a single 500-kV ac circuit for a single 800-kV dc line would be used.
(2) For transmission over 275 miles, two 500-kV ac lines or one 800-kV dc line would be used.
(3) Wheeling and displacement (see Sec. 3.3.4) are not considered in the cost model.
(4) Because Routes U-1 and N-1 were the shortest distances, they were the only routes considered for Utah and Nevada in the total cost model.
(5) All plant sites will be connected by backup transmission lines to the nearest alternative power tie-in.

Transmission Losses. For systems analysis purposes, we express transmission energy losses as the increase in power plant capacity that would be necessary to make the *net* capacity 1000 MW. For simplicity, we assume that all other inefficiencies, such as those arising from heat losses and air pollution control devices, have already been accounted for.

Alternating current energy losses are about 1.7% for each pair of terminals.[53] Joule heating consumes about 10 MW per 100 miles of transmission line,[54] and corona and reactive losses total about 2 to 4 NW per 100 miles;[53] we shall take 4 MW/100 miles as the more pessimistic figure.

If ETP is the number of miles of transmission line between a plant site and the Edmonston pumping station, then the ac line losses (in MW) are (0.10 + 0.04) * ETP. Let GCAP be the gross capacity (MW) such that the net plant capacity is 1000 MW. Then:

$$\mathrm{GCAP_{ac}} - (0.017 * \mathrm{GCAP} + 0.14 * \mathrm{ETP}) = 1000$$

$$\mathrm{GCAP_{ac}} = \frac{1000 + 0.14 * \mathrm{ETP}}{0.983} \quad . \tag{4-46}$$

When ETP is over 275 miles, two ac transmission lines will be needed (see Sec. 3.3.2); losses become 5 MW per 100 miles:

$$\mathrm{GCAP_{ac}} - 2 * (0.017 * \mathrm{GCAP} + 0.09 * \mathrm{ETP}) = 1000$$

$$\mathrm{GCAP_{ac}} = \frac{1000 + 0.09 * \mathrm{ETP}}{0.983} \quad . \tag{4-47}$$

Direct current terminal losses are 1.5%,[53,55] while line losses total 7.2 MW per 100 miles.[38] Equation (4-48) shows the gross capacity necessary for the net capacity to be 1000 MW for dc transmission:

$$\mathrm{GCAP_{dc}} = \frac{1000 + 0.072 * \mathrm{ETP}}{0.985} \tag{4-48}$$

The calculation of the effect of transmission losses on total cost is discussed in Sec. 4.1.2. Estimates of increases in power plant capacity for alternative routes and transmission modes are presented in Sec. 4.2.4.

Transmission Terminal and Line Costs. Table 4-8 shows the values used in estimating terminal and line costs.

Since 1 MW = 1000 kW, the ac and dc terminal costs are found by multiplying $\mathrm{GCAP_{ac}}$ and $\mathrm{GCAP_{dc}}$ by 26 000 and 154 000, respectively. Letting ETD be the sum of the length of primary transmission lines, ETP, and backup lines, ETS, combining the data in Table 4-8 with Eqs. (4-46) and (4-48), and simplifying, we have the electric transmission capital cost in dollars, TRAND:

<u>ETP < 275, ETS < 275:</u>

$$\mathrm{TRAND_{ac}}\ (\$) = 5.29 \times 10^4 * (1000 + 0.14 * \mathrm{ETP}) + 2.75 \times 10^5 * \mathrm{ETD} \quad . \tag{4-49}$$

<u>ETP < 275, ETS > 275:</u>

$$\mathrm{TRAND_{ac}}(\$) = 5.29 \times 10^4 * (1000 + 0.14 * \mathrm{ETP}) + 2.75 \times 10^5 * \mathrm{ETP} + 5.5 \times 10^5 * \mathrm{ETS} \quad . \tag{4-50}$$

<u>ETP > 275, ETS < 275:</u>

$$\mathrm{TRAND_{ac}}\ (\$) = 5.29 \times 10^4 * (1000 + 0.09 * \mathrm{ETP}) + 5.5 \times 10^5 * \mathrm{ETP} + 2.75 \times 10^5 * \mathrm{ETS} \quad . \tag{4-51}$$

<u>ETP > 275, ETS > 275:</u>

$$\mathrm{TRAND_{ac}}\ (\$) = 5.29 \times 10^4 * (1000 + 0.09 * \mathrm{ETP}) + 5.5 \times 10^5 * \mathrm{ETD} \quad . \tag{4-52}$$

$$\mathrm{TRAND_{dc}}\ (\$) = 2.213 \times 10^5 * \mathrm{ETD} + 1.563 \times 10^8 \quad . \tag{4-53}$$

TABLE 4-8

TRANSMISSION TERMINAL AND LINE COSTS

Cost Category	Transmission Mode		Reference Notes
	ac	dc	
Terminals (each)	\$13/kW	\$77/kW	56 and 57
Lines	\$275 000/mile	\$210 000/mile	55, 58, and 59

Annual capital costs are found by multiplying the appropriate TRAND by CRF. Since maintenance costs are negligible, the annual operating cost is limited to fixed charges; TRAND is multiplied by FCR. Electric transmission cost results are found in Sec. 4.2.4.

4.2. Cost Results

This section presents the results of applying the equations developed in Sec. 4.1 to real data. Most of the results were calculated with the aid of a computer code designed specifically for this analysis.

4.2.1. Coal Mining. We found that coal requirements depend heavily upon the choice of electrical transmission mode; scenarios using dc transmission lose less energy and thus require about 9% less coal. The heating value of the coal is also an important variable. Table 4-9 presents the average demand for coal from the 17 coalfields. Demands ranged from 2 730 000 tons/yr for a Book Cliffs-Barstow scenario with dc transmission to 4 380 000 tons/yr for a Great Divide and Little Snake River to Green River scenario with ac transmission.

Table 4-10 shows the coal costs for all feasible scenarios using ac transmission. Note that we have excluded shipment of southern Utah and New Mexico coal to the White Pine County and Green River power plant sites. For all scenarios, the coal costs for the dc electrical transmission modes are about 0.1—0.2 mills/kWh lower.

Coal mining costs represent from 15 to 25% of total project costs. If one excludes electrical transmission costs, then fuel and rail transportation costs combined are about 44 to 47% of the total, which compares favorably with the 40% of busbar costs reported in an *Electrical World* survey.[61]

4.2.2. Rail Transportation. An appreciation for the costs of transporting coal by unit train may be gained from examining a typical loading scenario. Let us assume that the railroad will have only 15 miles of new construction, and that it will haul coal with a heating value of 11 000 Btu/lb. Furthermore, let the power plant be served by 250 miles of ac transmission line. Then, by Eq. (4-39) in Sec. 4.1.2, the annual cost would be

$$\text{RRD (\$/yr)} = 2.269 \times 10^5 * \text{RAILD}^{**}0.609$$

$$+ 2298 * \text{RAILD} + 6.186 \times 10^6 \qquad (4\text{-}54)$$

Figure 4-5 shows the rail transportation cost in mills/kWh and mills/ton mile for the range of transportation distances from Rocky Mountain coalfields to the proposed power plants. Rail transportation will cost between about 2 and 4 mills/kWh. The costs per ton-mile agree excellently with the tariffs estimated by Bechtel Corporation.[37] They also appear quite reasonable when compared to the costs predicted by the Federal Energy Administration[35] and the US Bureau of Mines.[33] Indeed, for the 25-MTPY, 1000-mile (all new construction) scenario considered by the latter agency, our computer model predicts a total annual cost of 10.62 mills/ton-mile in 1977, compared to the Bureau's estimate of 8.77 mills/ton-mile in 1975.[48] Even though the Bureau's estimate, when inflated by the factors in Table 4-1, becomes 9.82 mills/ton-mile, our result would still only be about 8% too high.

Results for Scenarios. Table 4-11 shows the total rail distances used in the model. They were based on measurements on maps, consultations of railroad

TABLE 4-9

AVERAGE COAL DEMAND

Coalfield	Method	Heating Value Used in Model (Btu/lb)	Average Demand (10^6 tons/yr) ac	dc
Kaiparowits	UG	11 999	3.08	2.95
Alton	Surf	10 772	3.43	3.29
Star Lake	Surf	9 500	3.89	3.73
Book Cliffs	UG	12 762	2.89	2.77
Wasatch	UG	12 589	2.93	2.81
Emery	UG	11 424	3.23	3.10
Black Mesa	Surf	10 825	3.41	3.27
Gallup	Surf	10 637	3.47	3.33
Yampa	Surf	10 598	3.48	3.34
Kemmerer	Surf	9 683	3.81	3.66
Rock Spring	Surf	9 210	4.01	3.85
Great Divide and Little Snake River	Surf	8 377	4.41	4.23
Hanna	Surf	10 500	3.52	3.37
Sego and Book Cliffs	UG	11 000	3.36	3.22
Somerset	UG	11 500	3.21	3.08
Grand Hogback and Carbon-dale	UG	12 000	3.08	2.95
Evanston	UG	10 450	3.53	3.39

schedules, and, in the case of southern Utah routes, a prior optimization exercise (see below). It was assumed that, except when information indicated otherwise, there would be a 10-mile connection between the coalfields and the nearest mainline and a 5-mile spur from the mainline to the power plant. New construction mileages are shown in Table 4-12. Special construction was limited to 2 miles of bridges and 7 miles of tunnels for all routes out of Kaiparowits and 1 million cubic feet of cuts and fills for Alton routes. Average coal heating values were used for each coalfield.

Table 4-13 presents the total rail transportation costs for all practicable scenarios. We did not consider rail routes from Black Mesa; from New Mexico to Utah or Nevada; or from southern Utah to Green River. Since rail costs in ac and dc transmission scenarios generally differ by less than 0.1 mill/kWh, the table shows only the costs associated with the former.

Due to the need for extensive new rail, bridge, and tunnel construction, transportation scenarios originating in Kaiparowits would cost about 2.5 to 3.5 mills/kWh more than rail scenarios involving other coalfields. While this puts Kaiparowits at a slight disadvantage, it is not enough by itself to preclude Kaiparowits-based scenarios from consideration. Railroads from Alton would require a relatively large amount of new rail but no bridges or tunnels; rail costs are thus low enough to make an Alton-southern California option competitive.

In general, rail costs for Utah and Nevada power plants are lower than those for sites in southern California. The cheapest rail alternatives are those connecting mines and power plants within central Utah. The most expensive, aside from those from Kaiparowits, are routes from Wyoming to southern California.

In most cases, rail transportation costs represent 10 to 20% of the total project cost. Where coal is strip

TABLE 4-10

COAL MINING COSTS
(mills/kWh)

	Rice	Cadiz	Goffs	Barstow	Glamis	Blythe	Park	White Pine	Green River
Kaiparowits	4.7	4.7	4.7	4.6	4.7	4.7	4.7	x	x
Alton	2.0	2.0	2.0	2.0	2.0	2.0	2.0	x	x
Star Lake	2.2	2.2	2.2	2.2	2.2	2.2	2.2	x	x
Book Cliffs	4.1	4.0	4.1	4.0	4.1	4.1	4.1	4.1	4.1
Wasatch	4.1	4.1	4.1	4.0	4.1	4.1	4.1	4.2	4.2
Emery	5.4	5.3	5.3	5.3	5.4	5.4	5.4	5.4	5.5
Black Mesa	2.0	2.0	2.0	2.0	2.0	2.0	2.0	x	x
Gallup	2.1	2.1	2.1	2.0	2.1	2.1	2.1	x	x
Yampa	2.1	2.1	2.1	2.0	2.1	2.1	2.1	2.1	2.1
Kemmerer	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Rock Springs	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Great Divide and Little Snake River	2.5	2.4	2.5	2.4	2.5	2.5	2.5	2.5	2.5
Hanna	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Sego and Book Cliffs	5.5	5.5	5.5	5.4	5.6	5.5	5.5	5.6	5.6
Somerset	6.2	6.2	6.2	6.1	6.2	6.2	6.2	6.3	6.3
Grand Hogback and Carbon-dale	6.0	6.0	6.0	5.9	6.0	6.0	6.0	6.1	6.1
Evanston	5.8	5.8	5.8	5.7	5.8	5.8	5.8	5.8	5.9

x = excluded scenario.

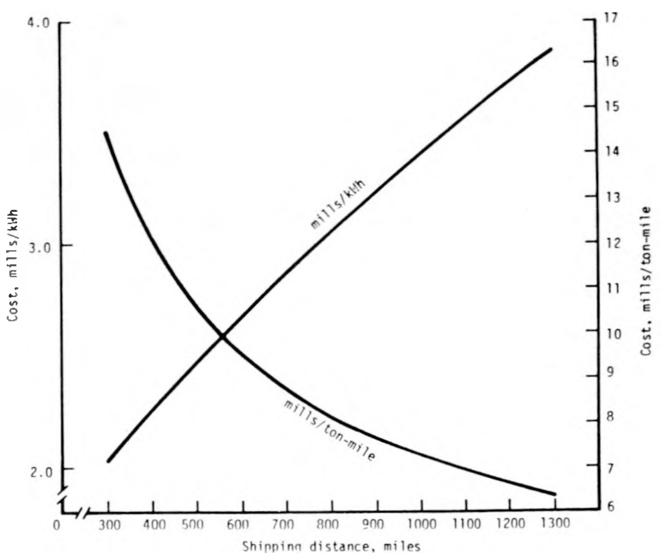

Fig. 4-5.
Rail transportation cost for typical scenarios.

TABLE 4-11

RAILROAD DISTANCES USED IN COST MODEL
(miles)

Mines	Plant Sites: Rice	Cadiz	Goffs	Barstow	Glamis	Blythe	Park	White Pine	Green River
Kaiparowits	977	927	996	829	1066	1036	1016	690	NC[a]
Alton	920	870	939	772	1009	979	959	633	NC
Star Lake	656	606	536	710	740	710	695	NC	NC
Book Cliffs	851	801	870	703	935	905	890	407	30
Wasatch	813	763	832	665	897	867	852	369	62
Emery	899	849	918	756	983	953	938	455	97
Black Mesa	NC	NC	NC	NC	NC	NC	NC	NC	NC
Gallup	534	484	414	588	618	588	573	NC	NC
Yampa	1215	1165	1234	1067	1299	1269	1254	608	370
Kemmerer	1031	981	1050	883	1115	1085	1070	439	201
Rock Springs	1061	1011	1080	913	1145	1115	1100	469	231
G.D. & L.S.R.	1111	1061	1130	963	1195	1165	1150	519	281
Hanna	1185	1135	1204	1037	1269	1239	1224	593	355
Sego & B.C.	1029	979	1048	886	1113	1083	1068	585	227
Somerset	1080	1030	1099	932	1164	1134	1119	488	250
G.H. & Carb.	1095	1045	1114	947	1179	1149	1134	483	245
Evanston	906	856	925	758	990	960	945	314	76

[a]Not considered.

mined, the rail transportation costs usually exceed those for the coal itself. For example, the Kemmerer coal mining cost is $4.16/ton, while the cost of shipping it to Cadiz is $7.08/ton (assuming an ac transmission scenario).

Southern Utah Route Optimization. One of the major goals of this study was to find the lowest cost rail route from Kaiparowits and Alton coalfields to southern California. Figures 4-6 and 4-7 show the network of existing and potential new rail lines serving Kaiparowits and Alton, respectively. All new rail segments are described in detail in Sec. 3.1.3. The circled numbers identify "nodes," which are defined as points where rail conditions change; e.g., where a new segment joins a preexisting main line. A "branch" is defined as a line connecting two nodes. Most of the segments described in Sec. 3.1.3 are branches in Figs. 4-6 and 4-7, although in a few cases two or more consecutive segments have been consolidated into a single branch. Tables 4-14 and 4-15 show the construction requirements for new rail segments.

Sophisticated network analysis techniques were considered unnecessary; instead, we enumerated all possible combinations of branches leading from each coalfield to each of the southern California plant sites. The task was simplified by the fact that all routes pass through Lund, Utah, on the Union Pacific mainline; in effect, the problem became that of minimizing the cost from the coal source to Lund. We calculated the total annual rail cost for each possible route and selected the cheapest. The nodes marking the optimum route are circled twice in Figs. 4-6 and 4-7.

For neither coal source would the shortest route be the cheapest. For example, a Sevier-Read link could cut up to 230 miles from the optimum Kaiparowits route, but would require 9 more miles of tunnels, plus an extra 44 miles of adjusted new rail [see Eq.

TABLE 4-12

NEW RAIL CONSTRUCTION REQUIREMENTS (miles)

	Plant Sites								
Mines	Rice	Cadiz	Goffs	Barstow	Glamis	Blythe	Park	White Pine	Green River
Kaiparowits	147	147	147	147	189	159	147	147	NC[a]
Alton	126	126	126	126	168	138	126	105	NC
Star Lake	15	15	15	15	57	27	15	NC	NC
Book Cliffs	15	15	15	15	57	27	15	15	30
Wasatch	15	15	15	15	57	27	15	15	15
Emery	15	15	15	15	57	27	15	15	65
Black Mesa	NC	NC	NC	NC	NC	NC	NC	NC	NC
Gallup	15	15	15	15	57	27	15	NC	NC
Yampa	15	15	15	15	57	27	15	15	15
Kemmerer	15	15	15	15	57	27	15	15	15
Rock Springs	15	15	15	15	57	27	15	15	15
G.D. & L.S.R.	15	15	15	15	57	27	15	15	15
Hanna	15	15	15	15	57	27	15	15	15
Sego & B.C.	15	15	15	15	57	27	15	15	15
Somerset	15	15	15	15	57	27	15	15	15
G.H. & Carb.	20	20	20	20	62	32	20	20	20
Evanston	15	15	15	15	57	27	15	15	15

[a]Not considered.

(4-13)]. The extra new construction cost would be 2.1 mills/kWh. The sensitivity of our results to unit rail, tunnel, and bridge costs is discussed in Sec. 4.3.4.

4.2.3. Coal Slurry Pipeline. Coal slurry pipeline costs were computed with Eq. (4-45). Generalized results for various throughputs over the range of transmission distances included in Rocky Mountain coal slurry scenarios are shown in Fig. 4-8. For any throughput the cost per ton-mile drops rapidly as the shipping distance increases from 300 to about 600 miles; thereafter, the cost declines less rapidly. Similarly, for a given shipping distance, there is a large decrease in unit cost as the throughput increases from 2 to 3 Mton per year, yet only half that decreases as the throughput goes from 3 to 4 Mton per year.

Results for Scenarios. Table 3-3 in Sec. 3 listed the distances for several alternative coal slurry pipelines from Utah and Arizona to southern California. For the total cost model, we chose the shortest routes. We did not consider any pipelines to central Utah or White Pine County, Nevada.

Table 4-16 presents the coal slurry transportation cost results. Since the costs for ac and dc transmission differ by an average of only 0.02 mill/kWh, only the former are reported. When coal slurries are used, transportation costs represent about 16% of total project cost, compared to about 10 to 20% for rail transportation.

Pipeline costs for coal shipped from Kaiparowits and Alton are essentially the same for the four Mojave Desert plant sites, but it is slightly cheaper to ship from Kaiparowits to Glamis, Blythe, and Parker Valley than it is to ship from Alton. Since,

TABLE 4-13

TOTAL RAIL TRANSPORTATION COSTS
(mills/kWh)

	Plant Sites								
Mines	Rice	Cadiz	Goffs	Barstow	Glamis	Blythe	Park	White Pine	Green River
Kaiparowits	6.4	6.3	6.4	6.1	7.2	6.7	6.5	6.2	NC[a]
Alton	5.0	4.9	5.0	4.8	5.9	5.4	5.1	4.6	NC
Star Lake	3.2	3.0	2.9	3.2	4.0	3.5	3.2	NC	NC
Book Cliffs	4.1	2.7	2.8	2.5	3.5	3.0	2.8	2.0	1.3
Wasatch	2.7	2.7	2.7	2.5	3.5	3.0	4.1	1.9	1.2
Emery	3.1	3.0	3.1	2.8	3.9	3.4	3.2	2.3	2.1
Black Mesa	NC	NC	NC	NC	NC	NC	NC	NC	NC
Gallup	2.6	2.5	2.3	2.7	3.4	2.9	2.7	NC	NC
Yampa	3.9	3.8	3.9	3.6	4.7	4.1	3.9	2.8	2.3
Kemmerer	3.8	3.7	3.9	3.5	4.7	4.1	3.9	2.6	2.0
Rock Springs	4.1	4.0	4.1	3.7	4.9	4.4	4.2	2.8	2.2
G.D. & L.S.R.	4.5	4.4	4.6	4.2	5.4	4.9	4.6	3.1	2.4
Hanna	3.8	3.7	3.9	3.5	4.6	4.1	3.9	2.8	2.3
Sego & B.C.	3.4	3.3	3.5	3.1	4.2	3.7	3.5	2.7	1.9
Somerset	3.4	3.3	3.4	3.1	4.2	3.7	3.5	2.4	1.9
G.H. & Carb.	3.4	3.3	3.4	3.1	4.1	3.6	3.4	2.4	1.9
Evanston	3.4	3.3	3.4	3.1	4.2	3.7	3.5	2.2	1.4

[a]Not considered.

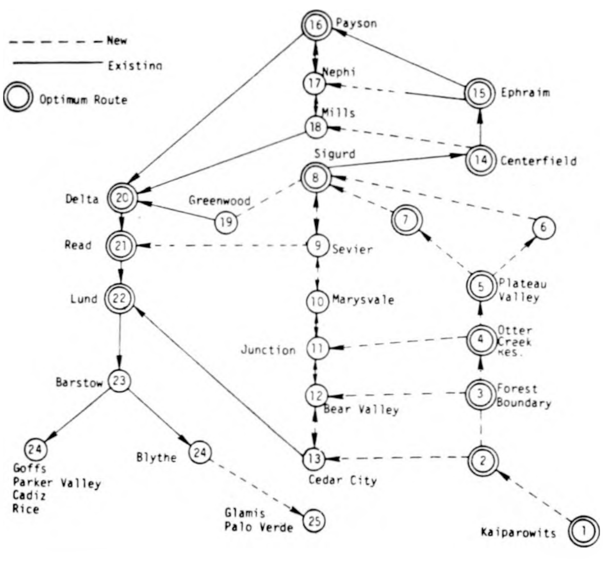

Fig. 4-6.
Kaiparowits-southern California rail network.

however, the range of costs reported is so small (from 2.63 mills/kWh for Alton-Goffs to 3.35 mills/kWh for Black Mesa-Barstow) there is essentially no cost difference among the 21 alternatives.

4.2.4. Electric Transmission. Electric transmission distances, shown in columns 2 and 3 of Table 4-17, were found by measurement on maps. Except for Utah and Nevada power plant scenarios, no attempt was made to define precise routes. Distances were made as short as possible, except that mountainous terrain was avoided whenever possible. The cost estimates made here are thus subject to considerable uncertainty. We assumed that each power plant would be connected to the Edmonston Pumping Station and, with a backup line, to either Victorville or the Mohave Plant in Nevada, whichever was closer.

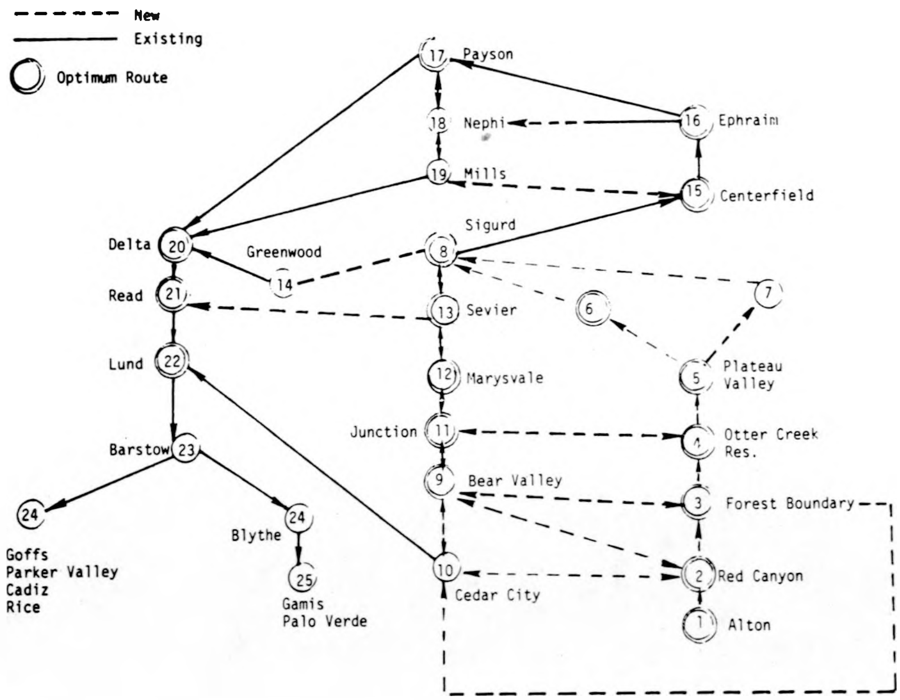

Fig. 4-7.
Alton-southern California rail network.

TABLE 4-14

NEW CONSTRUCTION REQUIREMENTS FOR KAIPAROWITS RAIL SEGMENTS

Branch[a]	New Rail (miles)	Adjusted[b] New Rail (miles)	Bridges (miles)	Tunnels (miles)	Cuts and Fills (10^6 ft^3)
1-2	17	19	0.5	0	0
2-3	27	37	0.5	7	0
2-13	190	263	3.5	4.5	11
3-4	29	31	0	0	0
3-12	38	40.5	0	4	1
4-5	32	32	0	0	0
4-11	14	14.25	0	0	0
5-6	21	30	0	0	0
5-7	15	20.25	0	0	0
8-19	47	54.5	0	0	0
9-21	42	44	0	9	0
10-11	16	20	0	0	0
11-12	24	26	0	0	0
12-13	67	71.5	0	3.2	0.47
14-18	32	32.5	0	0	0.03

[a]See Fig. 4-6.
[b]See Eq. (4-13) and preceding discussion.

TABLE 4-15

NEW CONSTRUCTION REQUIREMENTS FOR ALTON RAIL SEGMENTS

Branch[a]	New Rail (miles)	Adjusted[b] New Rail (miles)	Bridges (miles)	Tunnels (miles)	Cuts and Fills (10^6 ft^3)
1-2	30	31	0	0	0.5
2-3	22	22.5	0	4	0
2-9	16	17	0	0	0.5
3-4	29	34	0	0	0
3-10	217	300	4	11.5	11
4-5	32	32	0	0	0
4-11	14	14.25	0	0	0
5-6	15	20.25	0	0	0
5-7	21	30	0	0	0
8-14	47	54.5	0	0	0
9-10	67	71.5	0	3.2	0.47
9-11	24	26	0	0	0
11-12	16	20	0	0	0
13-21	42	44	0	9	0
15-19	32	32.5	0	0	0.03

[a]See Fig. 4-7.
[b]See Eq. (4-13) and preceding discussion.

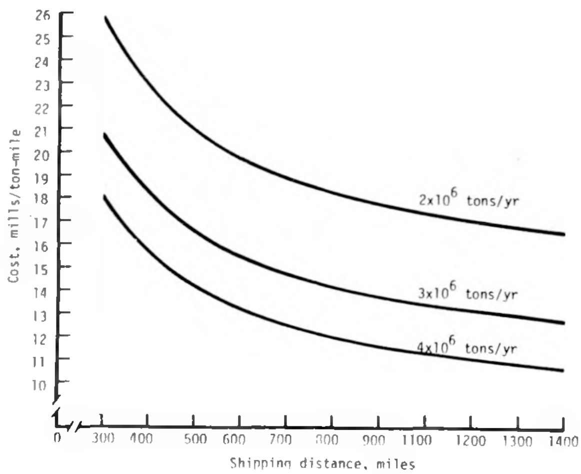

Fig. 4-8.
Slurry pipeline cost for typical scenarios.

TABLE 4-16

COAL SLURRY PIPELINE COST RESULTS (mills/kWh)

	Coal Source		
Power plant Site	Kaiparowits	Alton	Black Mesa
Rice	2.87	2.93	2.93
Cadiz	2.87	2.81	3.03
Goffs	2.68	2.63	2.81
Barstow	3.04	3.06	3.35
Glamis	3.10	3.28	3.18
Blythe	2.96	3.13	3.02
Parker Valley	2.85	3.03	2.84

TABLE 4-17

ELECTRIC TRANSMISSION PARAMETERS AND COST RESULTS

Power plant Site	Distance to Edmonston (miles)	Distance to Secondary Tie-in (miles)	Total New Line (miles)	Plant Capacity Increase Factor[a]		Total Cost (mills/kWh)	
				(ac)	(dc)	(ac)	(dc)
Rice	230	75	305	1.05	1.03	2.12	3.43
Cadiz	193	61	254	1.04	1.03	1.90	3.26
Goffs	209	28	237	1.05	1.03	1.83	3.20
Barstow	91	28	119	1.03	1.02	1.32	2.80
Glamis	268	142	410	1.06	1.03	2.57	3.78
Blythe	264	99	363	1.05	1.03	2.37	3.63
Parker Valley	264	63	327	1.05	1.03	2.22	3.50
White Pine County	505	316	821	1.06	1.05	7.76	5.18
Green River	610	284	894	1.07	1.06	8.39	5.43

[a]Calculated from Eqs. (4-46), (4-47), or (4-48).

As noted in Sec. 4.1.4, transmission losses require an increase in plant capacity, so that the net capacity may be 1000 MW. Columns 5 and 6 of Table 4-17 show the increase factor for ac and dc transmission scenarios, respectively. In all cases, dc transmission incurs less energy loss, and all the California sites would require from 2 to 6% more plant capacity by using ac transmission. The Utah and Nevada sites, using two ac transmission lines each, would require only 1% more capacity.

For all the California sites, ac transmission proved to be cheaper than dc, in keeping with assertions made in Sec. 3.3.3. However, for long transmission distances, such as those from Utah and Nevada, dc is about 35% less expensive.

The Utah and Nevada ac transmission costs exceed the cost of energy transportation by rail for comparable distance, at least for a 7×10^9 kWh annual demand. If economics were the only consideration, it would be cheaper to ship central Utah coal to southern California and burn it there than to export power via an ac line from a mine-mouth plant. On the other hand, dc costs are comparable to rail costs and, as will be seen in Sec. 4.2.10, mine-mouth and southern California plant site options cost about the same, as far as central Utah coal is concerned.

4.3. Systems Analysis

One of the advantages of using a computer model to calculate project costs is the ability to consider a great number of variations to the basic program. One cannot only compare many scenarios, but can also determine what effect changing some of the "ground rules" has upon total costs and ranking. For example, some scenarios may be more capital-intensive than others, so that increasing capital-related costs or parameters (i.e., CRF and FCR) could affect them more than it would others. In this section we shall first analyze further some of the results presented in Sec. 4.2 and then analyze the model itself.

4.3.1. Analysis of Two Typical Scenarios. By analyzing two scenarios in detail we can understand better the role that different cost constituents play in total cost. In addition, we can determine the economic consequences of political or environmental policy decisions; for example, scenarios whose high-ranking results from the use of pipelines for coal transportation would be especially vulnerable to adverse court decisions on eminent domain.

Given the enormous variation within the four parameters used in the cost model, it is unrealistic to propose a "typical scenario" for analysis. We can, however, select two scenarios in such a way that cost trade-offs become apparent. One of these would involve shipment of coal by rail from Book Cliffs, Utah, to Cadiz, California, followed by ac transmission to Edmonston; we shall call this Scenario A. Scenario B would have coal shipped by rail from Kemmerer, Wyoming, to White Pine County, Nevada; transmission to Edmonston would be dc.

The cost breakdowns for these scenarios were calculated. Although the total project costs are similar, there is significant variation in the coal mining and electric transmission categories. Scenario A would require 2.8 Mton per year of coal and incur 1.84 mills/kWh more in mining costs than would Scenario B, although the latter would use 3.7 Mton per year. The reason for Scenario B's mining cost advantage is that the coal at Kemmerer would be strip mined, while that at Book Cliffs would be deep-mined.

The coal mining cost advantage is more than offset, however, by the very large cost of electric transmission from Nevada to southern California. One of the reasons Scenario B requires more coal is that, although dc transmission is generally more efficient than ac over long distances, line energy losses are still quite high for a route of this length. Scenario B would be very competitive if one of the alternative means of power distribution discussed in Sec. 4.3 were used.

Scenario B's shorter rail distance (439 vs 801 miles) more than offsets its higher coal requirement. Total railroad capital costs for the two scenarios are almost the same, but Scenario B's non-capital-related costs are $725 000 per year below those for Scenario A.

4.3.2. Comparison of Slurry and Rail Transportation Costs. A subject of current intense interest—and controversy—in fuel transportation is the comparative economics of rail and slurry coal transportation. We shall not attempt to give the final, definitive answer here, but we can draw conclusions for our specific project. Figure 4-9 shows the cost per ton-mile for coal shipment by rail with no new construction, rail with 40% new construction, and slurry pipeline. We assumed a coal heating value of 11 000 Btu/lb and 250 miles of ac transmission. As a result, the annual throughput would be 3 269 000 tons of coal. It should be emphasized that pipeline diameters, and hence construction costs, vary with throughput (see Fig. 3-8, Sec. 3), so that the costs per ton-mile reported here cannot be compared to those for, say, the 25-MTPY, 1000-mile ETSI pipeline.

It is apparent from Fig. 4-9 that, over the range of shipping distances likely to be encountered, shipment over a rail line requiring no new construction would have the lowest cost per ton-mile. Slurries are therefore not competitive for most of the scenarios using extensive existing rail. Slurries are, however, considerably cheaper than all-new railroads, which explains why Alton-southern California scenarios using pipelines are so favorable in the DWR analysis.

The advantage of existing rail over slurries increases slightly with increasing shipping distance. Slurries can compensate somewhat for this trend, however, by taking shorter, more direct routes. This possibility applies especially well to shipment over

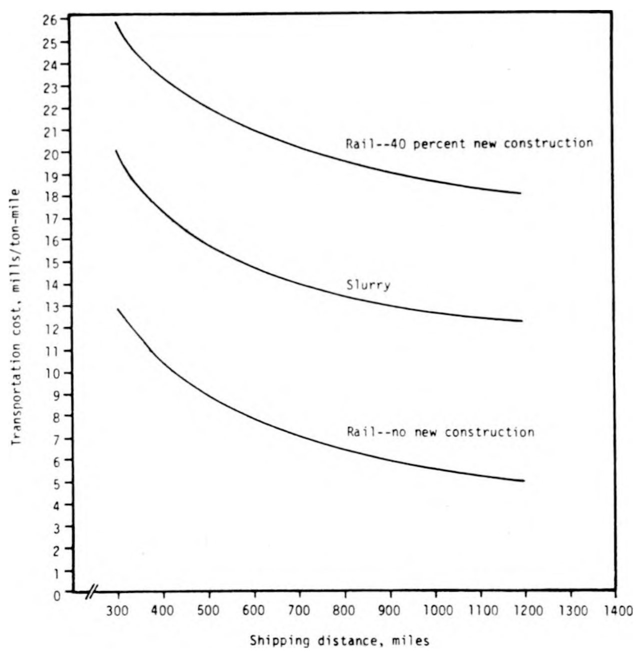

Fig. 4-9.
Unit train and slurry pipeline costs.

rough terrain. Another item of interest is the breakpoint percentage of new rail construction at which the railroad cost per ton-mile exceeds that for a slurry of equal length. Over the range of distance and throughputs considered here, a slurry pipeline is equivalent to a railroad with about 22% new rail.

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1. N. N. Barish, *Economic Analysis for Engineering and Managerial Decision-Making* (McGraw-Hill Book Co., New York, 1962), p. 54.

2. Throughout this report FORTRAN computer language notation is used for multiplication, exponentation, and other mathematical operations. One asterisk (*) is equivalent to a multiplication sign; two asterisks (**) denote exponentation.

3. L. H. Harvego, in letter to Orson L. Anderson, p. 3 (April 16, 1976).

4. R. C. Petruschell and R. G. Salter, "Electricity Generating Cost Model for Comparison of California Power Plant Siting Alternatives," Rand Corporation report R-1087-RF/CSA (1973), p.17.

5. *Business Statistics, 20th Biennial Edition*, pp. 49 and 55; *Survey of Current Business* 56(11): 5-11, US Dept. of Commerce, Bureau of Economic Analysis (1976).

6. Federal Energy Administration (1974).

7. Cubic yards of overburden per ton of coal mined. This ratio is approximately three times higher than it should be for the areas of interest.

8. Equals net profit plus depreciation plus maximum allowable depletion.

9. Equals operating cost plus 2 (net profit) plus depletion allowance.

10. Equals sales minus operating costs.

11. Equals 10% of sales.

12. Equals gross profit minus depletion allowance.

13. 50%.

14. Surface mines would load three shifts per day, 250 days/yr, although stripping would be carried out 24 h/day, 336 days/yr. Underground mines would operate three shifts/day, 225 days/yr with the third shift being a maintenance shift.

15. 35% of payroll.

16. 15% of labor and supplies.

17. Straight line depreciation, generally over 20 yrs.

18. Engineering News-Record **194**(4), p. 52 (1975).

19. Engineering News-Record **192**(7), p. 3 (1974).

20. Engineering News-Record **192**(10), p. 18 (1974).

21. Reference 18, p. 31.

22. Engineering News-Record **194**(10), p. 3 (1975).

23. Engineering News-Record **194**(11), p. 5 (1975).

24. Engineering News-Record **194**(14), p. 3 (1975).

25. Reference 18, p. 57.

26. Engineering News-Record 195(5), p. 36 (1975).

27. Engineering News-Record **195**(9), p. 40 (1975).

28. Engineering News-Record **195**(11), p. 49 (1975).

29. Engineering News-Record **191**(10), p. 40 (1973).

30. Engineering News-Record **191**(23), p. 53 (1973).

31. Engineering News-Record **192**(10), p. 42 (1974).

32. Unit rail costs for three proposed new railroads in Utah and New Mexico range from $714 000 to $2 368 000 per mile (see Refs. 14, 16, and 17). Lower and higher estimates also exist. To aid in computations and remain within the reported cost range, we set the unit rail cost at $1 000 000 per mile.

33. Comparison of economics of several systems for providing coal-based energy to users 1000 miles southeast of eastern Wyoming coalfields—four modes of energy transportation and electricity vs gas as the end use energy forms. In *Hearings Before the Committee on Interior and Insular Affairs, House of Representatives, 94th Congress, First Session on H. R. 1863, H. R. 220, H. R. 2553, and H. R. 2986* (Coal slurry pipeline legislation), US Bureau of Mines, p. 351 (1975). Cost inflated to mid-1976 dollars.

34. T. H. Pigford, M. F. Keaton, B. J. Mann, P. M. Cukor, and G. L. Sessler, "Fuel Cycles for Electric Power Generation," Teknekron, Inc., EPA No. 68-01-0561 (1975), p. 84.

35. *Project Independence Blueprint Inputs to the Project Independence Evaluation. System Integration Model for the Transport of Energy Materials. Vol. II*, Federal Energy Administration (1974).

36. P. Buck and N. Savage, "Determine Unit Train Requirements," Power **118**(1):90-91 (1974).

37. R. H. Leilich and J. Williams, "Railroad Freight Car Requirements for Transporting Energy, 1974-1985," prepared by Peat, Marwick, Mitchell and Company for the Federal Energy Administration (1974).

38. Ref. 35, p. III-15.

39. Ibid., p. III-14.

40. Ref. 37, p. III-10.

41. Ibid., p. III-16.

42. E. Welty, "Unit Trains: Traffic by the Trainload," Railway Age **174**(18):22-32, p. 26 (1973).

43. "A Report to the Interagency Task Force, A Project Independence Blueprint, on the Modal Transportation Costs for Coal in the United States," Battelle Columbus Laboratories, prepared for TRW Systems, Inc., 81 p., p. 67 (1974). Bottom dump hopper cars cost $26 000 each and locomotives cost $325 000 each in 1974.

44. Ref. 37, p. III-28.

45. Ibid., p. III-29.

46. Ibid., p. III-30.

47. "Clean Coal Energy: Source-to-Use Economics, Phase I Report," Bechtel Corporation, p. 2-29 (Available from NTIS as FE-1552-TI).

48. Ref. 33, p. 352.

49. The Bureau of Mines study estimated, by a method independent from that of Ref. 37, a 1975 tariff of 8.8 mills/ton-mile, so our estimate is in the right ballpark.

50. *Project Independence Blueprint, Analysis of Requirements and Constraints on the Transport of Energy Materials, Vol. I*, Federal Energy Administration, p. VII-7 (1974).

51. Ref. 35, p. VII-12.

52. Ibid., p. VII-11.

53. *500-kV Long-Distance Electric Transmission*, A. M. Nekrasov and S. S. Rokotyan, Eds., US Department of Commerce (1966), p 12.

54. "The 1970 National Power Survey," US Federal Power Commission, (1971).

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59. Costs include approximately $25 000/mile for right of way.

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61. L. M. Olmstead, "19th Steam Station Cost Survey," Electrical World **184**(10:43-58), p. 47. Transportation costs are assumed to have been included in fuel costs in this reference.

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