IV. Coal Slurry Pipeline and Unit Train Systems

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Assessing the costs and benefits of rail and pipeline alternatives required first, the establishment of coal transportation market projections and second, the development of cost relationships and traffic scenarios for the two modes. Since the extent and pattern of transportation activity depend on the cost and configuration of the system, these two steps cannot be separated entirely, and the market projections were later tested for sensitivity to transportation costs. This chapter contains a brief description of the competing technologies followed by the results of the two analyses just mentioned.

TECHNOLOGY DESCRIPTION

Pipelines

Slurry pipelines have been proposed as a method for moving large volumes of coal over great distances. Two such pipelines have been built in this country, one is in operation, and several are in different stages of planning (see figure 1), The economic and environmental advantages and limitations are a matter of considerable dispute. In the absence of waterways, however, pipelines are claimed to be potential competitors for coal traffic in volumes of more than approximately 5 million tons per year over distances greater than about 200 miles, particularly where rail facilities are circuitous or in poor condition.

The process involves three major stages: 1) grinding the coal and mixing it with a liquid (generally water) to form the slurry, 2) transmission through the pipeline, and 3) dewatering the coal for use as a boiler fuel, for storage, or for transloading to another mode of transportation. These steps are diagramed in figure 2, and some characteristics of selected coal and other mineral slurry pipeline systems are presented in table 1.

Slurry Preparation

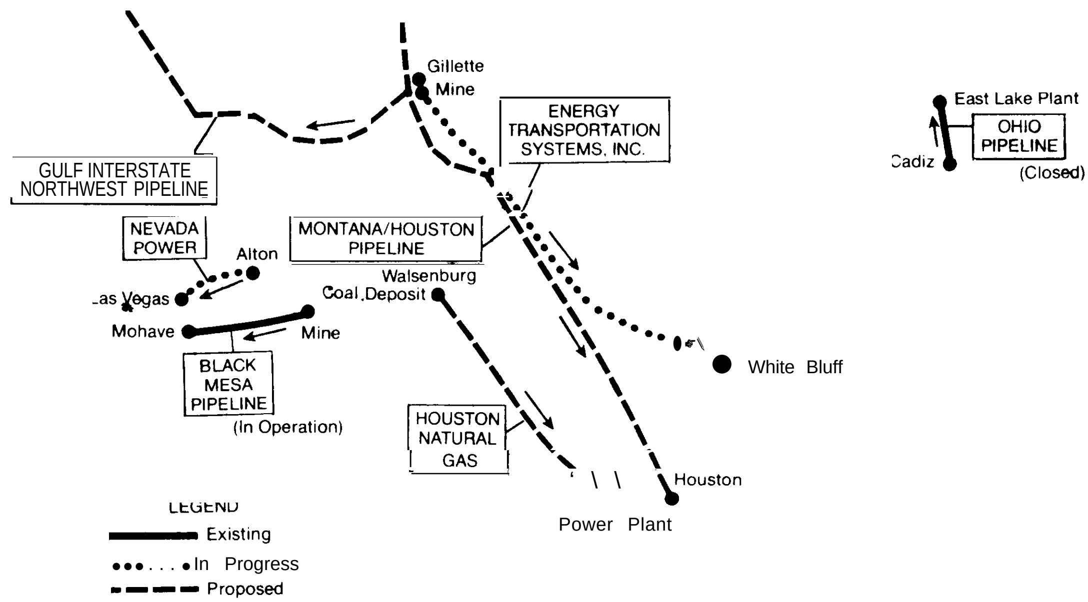
Coal is assembled from a mine or group of mines at a single point where mixing, cleaning, or other beneficiation may take place, and where the slurry is prepared. Preparation begins with impact crushing followed by the addition of water and further grinding to a maximum particle size of one-eighth inch. More water is then added to form a mixture that is about 50 percent dry coal by weight, and the resulting slurry is stored in a tank with mechanical agitators to prevent settling.

The optimum size distribution of the coal and proportion of water is dependent on design tradeoffs that are peculiar to the specific application, and water requirements are reduced to the extent of the initial moisture content of the coal. Water is also not necessarily the only slurry medium, and oil as well as methanol derived from the coal itself have been proposed.

Transmission

The slurry from the agitated storage tanks is introduced into a buried steel pipe and propelled by reciprocating positive displacement pumps located at intervals of approximately 50 to 150 miles, depending upon terrain, pipe size, and other design considerations. The slurry travels at a velocity just under 6 feet per second, but the precise speed also depends on the coal particle size distribution, pipe diameter, and economic factors. Ideally, the

Figure 1—Present and Proposed Coal Slurry Pipelines



Source: Slurry Transport Association.

flow is maintained at a rate which minimizes power requirements while maintaining the coal in suspension. Once started, the flow must continue uninterrupted, or the coal will gradually settle and possibly plug the pipe. Considerable technical controversy surrounds the likelihood of this event and the possibility that the pipeline can be restarted after given periods of time. To prevent this type of settling, the operating pipeline at Black Mesa has ponds into which to empty the pipe in the event of a break or other interruption.

The potential economic advantage of this technology lies in the fact that the volume of coal that can pass through a pipeline increases approximately as the square of the pipeline diameter, while construction, power, and other operating costs do not rise in as high a proportion. Therefore, if throughput volumes are high enough to take advantage of this economy of scale, and if the pipeline is long enough to recover the cost of gathering, preparing, dewatering, and delivering the coal at the termini, the pipeline can compete with unit trains.

Dewatering and Delivery

At the downstream end of the pipeline, the slurry is again introduced into agitated tank storage, from which it is fed into a dewatering facility. Dewatering is accomplished by natural settling, vacuum filtration, or by centrifuge, and then the finely ground coal still suspended in the water can be separated by chemical flocculation. After additional drying by the application of heat, the coal can then be stored, transported further by other modes, or introduced directly into grinding equipment at a powerplant and injected into the boilers. The reclaimed water can be used in an electric generating station's cooling system to condense steam, or it could theoretically be recycled in a return pipeline.

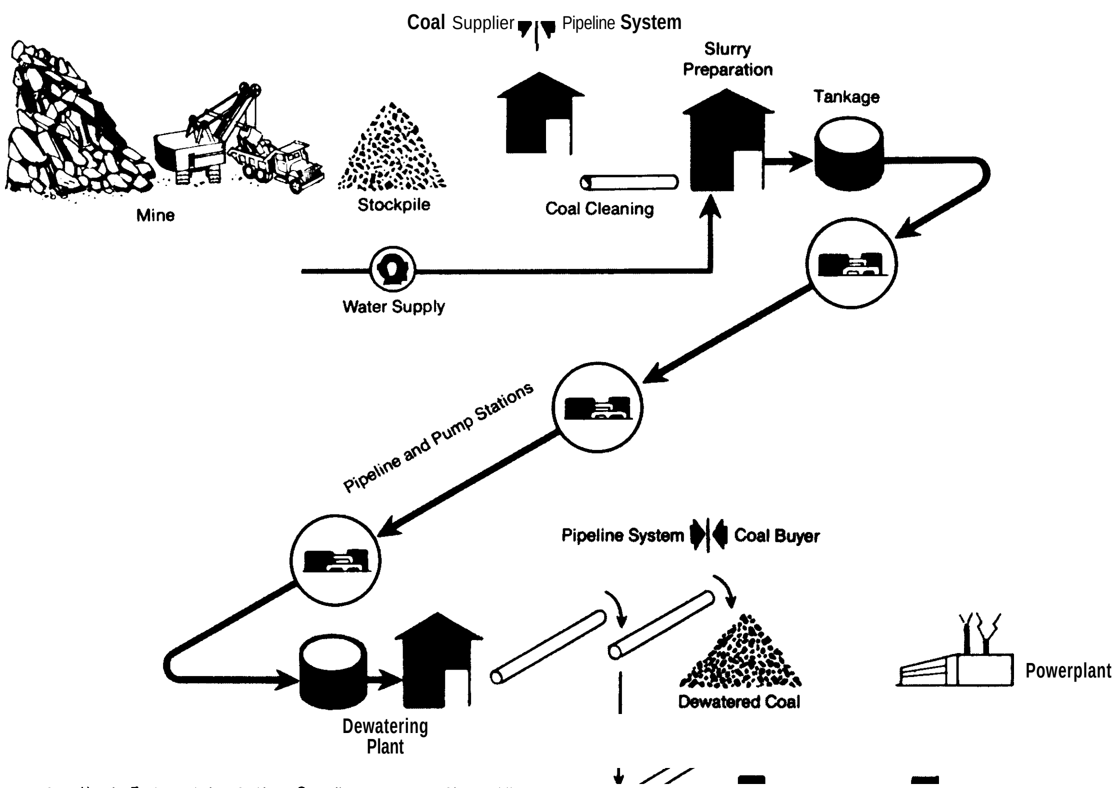
Possible variations on this stage, which are not covered by this assessment, include introduction of coal slurry as a feedstock for gasification or liquefaction facilities designed to take into account the fact that the coal is already ground and mixed with water, or the use of a combustible slurry medium like oil or methanol so that dewatering would not be necessary and the slurry could be used as a boiler fuel directly.

Unit Trains

The principal economic competitors with coal pipelines are unit trains. This type of train, also designed to take advantage of scale economies, generally carries a single commodity in dedicated service between two points in sufficient volume to achieve cost savings. The cars are designed for automated loading and unloading, and the train is operated according to procedures which avoid switching and time-consuming delays in freight yards.

A typical coal unit train consists of six 3,000 horsepower locomotives and 100 hopper cars with carrying capacitates of 100 tons each. Roughly two such trains per week are therefore required to deliver 1 million tons of coal per year. Speeds vary considerably depending on track conditions, but 20 to 50 miles per hour is a common range. Trains generally travel more slowly loaded than empty.

Figure 2–Schematic of Slurry Pipeline System



Source John M Huneke, Testimony before the House Committee on Interior and Insular Affairs on Coal Slurry Pipeline Legislation, Washington, D C Sept. 12, 1975

COAL SLURRY. — Aerial view of the Black Mesa Slurry Preparation Plant and Pumping Station near Kayenta, Ariz.

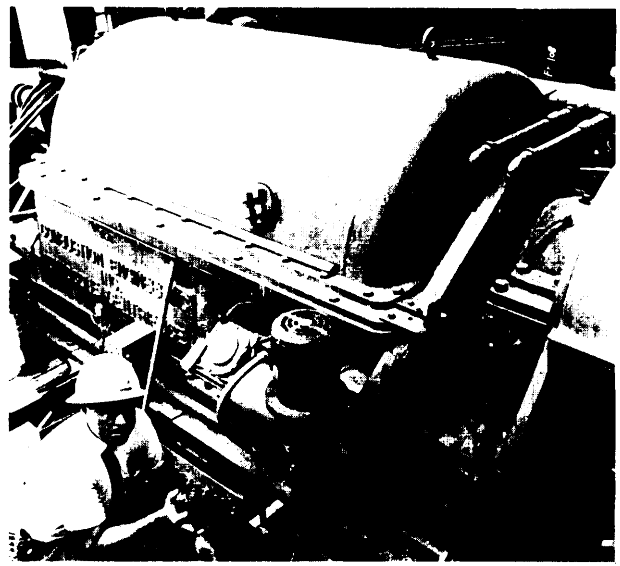


Photo: Courtesy of Southern California Edison Company

CENTRIFUGES. – Southern California Edison Company employee in foreground holds lump of coal which is finely ground at Black Mesa, Ariz., before it goes through 273-mile slurry pipeline mixed with water (50-50%) and slurried to huge circulating facilities — holding tanks — at Mohave Generating Station. From holding tanks the coal/ water solution is sent into one of 40 centrifuges (20 for each generating unit) where the coal is dewatered before it goes into boiler furnaces.

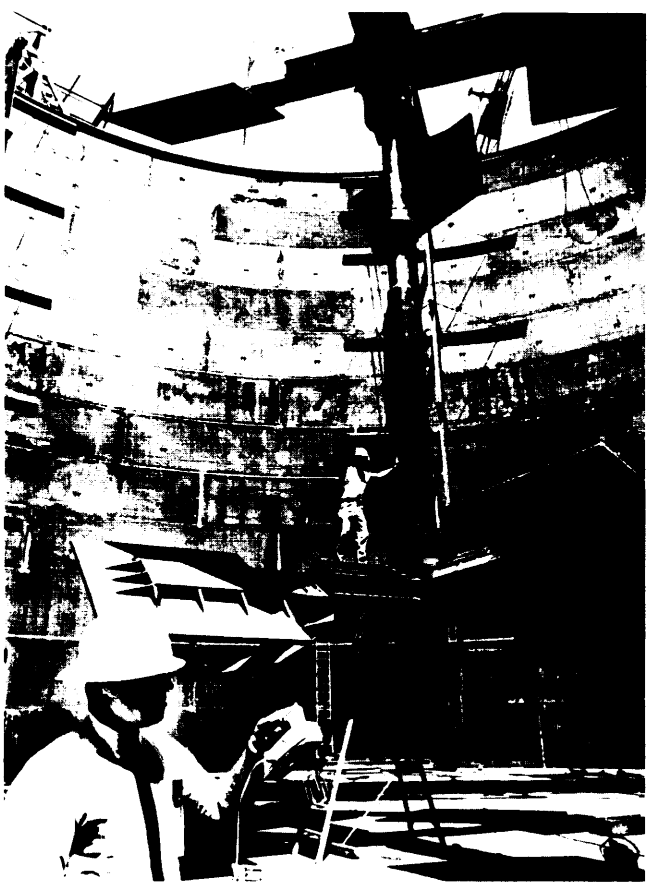


Photo: Courtesy of Southern California Edison Company

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GIANT MIXERS. – Inside one of the huge mixing tanks, personnel at the Mohave Power Project display a kitchen-size electric mixer to give some comparison with the world's largest mixing blades — used to keep powder-fine coal in water solution (slurry). A battery of smaller centrifuges later expel the water from the coal before the fuel is used to create electricity for three Southwest States, Nevada, Arizona, and California.

COAL MINING. – A thick seam of coal exposed by stripping, done by the big dragline, is being loaded into the Dart hauler by a front-end loader.

Photo: United States Department of Energy

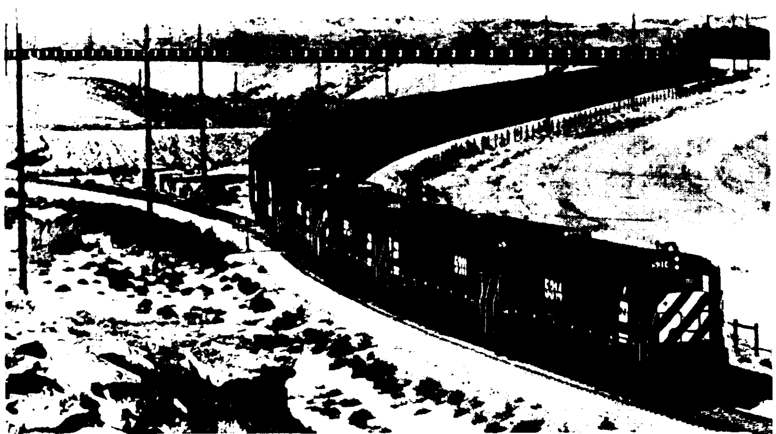


Photo. Burlington-Northerrn, Inc.

COAL UNIT TRAINS. – Like the one depicted in this photo, typically utilize 6 locomotives and 100 hopper cars. The trains are frequently more than a mile long.

COAL. – Sub-bituminous coal underlies some 25,000 square miles of Montana and Wyoming.

Table 1. Summary of Selected Worldwide Commercial Slurry Pipelines

Slurry material	System or location	Length (miles)	Diameter (inches)	Annual throughput (million tons/year)	Initial operation
	Existing				
Coal.	Consolidation	108	10	**1.3**	1957
	Black Mesa	273	18	**4.8**	1970
Limestone	Calaveras	17	7	1.5	1971
	Rugby	57	10	1.7	1964
	Trinidad	6	8	0.6	1959
	Colombia	17		0.4	1944
Copper Concentrate.	Bougainvillea		6	1.0	1972
	West Irian	69	4	0.3	1972
	KBI Turkey	38	5	1.0	——
	Pinto Valley	11	4	0.4	1974
Magnetite Concentrate . . .	Tasmania	53		2.3	1967
	Waipipi (land)	4	8	1.0	971
	Waipipi (offshore)	1.8	12	1.0	971
	Pena Colorada	30	8	**1.8**	974
Gilsonite. ... , ...	Am. Gilsonite	72	6	0.4	957
Tails	Japan	44	12	0.6	968
Nickel refinery tailings. . . .	West. Mining	4.3	4	0.1	970
	In Progress				
Coal.	**Nevada** Power Utah/Nev.	180	24	10.0	
	Energy Trans. Systems, Inc. Wyo./Ark.	1,036	38	25.0	
Magnite and Hematite	Sierra Grande	20	8	2.1	
	Brazil	250	20	12.0	
	Mexico	17	10	1.5	
	Planned				
Coal.	Houston Nat. Gas Colo. to Tex.	750	22	9.0	
	Gulf Interstate N.W. Pipeline	800	30	16.0	
Phosphate	Australia	200	16-22	4.0-6.0	
Sulfur/hydrocarbon.	Canada	800	12-16	—	
Magnetite and hematite. . .	Africa	350	18	6.6	
	Brazil	240	20	12.0	
	India	36	20-22	10.0	
	Mexico	17	10	1.5	
	Australia	44	8	0.9	

[a]No longer in operation.

Source: John M. Huneke, Testimony before **the House Committee on Interior and Insular Affairs on Coal Slurry Pipeline Legislation, Washington, D. C., Sept. 12,1975.**

Since these trains are frequently more than 1 mile in length, one of the problems associated with their use is the interruption of traffic at crossings, especially where they arrive frequently and travel slowly. Also, trains of all kinds produce substantial amounts of noise, and they contribute to community and land-use disruption as well as to a component of highway traffic accidents. However, compared to pipelines, railroads offer advantages in terms of flexibility of operation and absence of water requirements at the coal source.

To benefit from this improved service, a customer must ship quantities sufficient to justify economically a dedicated train and often must invest in rapid loading and unloading facilities *to* meet turnaround time requirements. Also, it is sometimes to the customer's advantage to own the railroad cars as well.

COAL TRANSPORTATION MARKET

As the use of coal for powerplant fuel accounts for approximately 65 percent of all domestic coal use, changes in demand for utility coal will have major ramifications for the coal industry as a whole and the industries involved in its transport. The complexity of the problem is increased by the uncertainties faced by electric utilities. In addition to questions of economic viability, expansion potential, and electrical demand, the utilities must also consider future pollution-control requirements that are directly relevant to their selection of fuel type for new plant construction. As nuclear and coal-fired powerplants are approaching equivalence in life cycle costs, stringent pollution-control requirements can play a significant role in the nuclear/coal tradeoff. Pollutant-emission limitations also affect the type of coal to be burned once the decision to build a coal-fired plant is made. As coal types are geographically localized, intentions to burn specific coals add a spatial dimension to the utility demand for coal.

To determine what patterns of coal use utilities are likely to pursue under various scenarios of electrical demand growth, generating plant configuration, and environmental regulation, this study employed a utility simulation model developed under the sponsorship of the Environmental Protection Agency (EPA). The model simulates the behavior of the electric utility industry on a State-by-State basis when economic, technical, and environmental parameters are specified. For this analysis, several scenarios have been employed to bound the range of likely utility response to various levels of electrical demand and pollution-control requirements. Detailed tables and maps have been prepared that specify the type, amount, origin, destination, and year of coal demand for the utilities in response to each scenario.

Significant variations in production at the regional level can be attributed to anticipated changes in pollution-control requirements as well as to overall demand growth rates. Under current regulations, States must have plans to improve and maintain ambient air quality to levels specified by National Ambient Air Quality Standards (NAAQS). In addition, emission limitations are expressly provided for the construction of new sources in operation after 1977. Utility response to these requirements have been, up to now, a process of deciding whether to use low-sulfur coals or flue-gas desulfurization equipment. This strategy encourages the use of low-sulfur western coals able to meet the emission limitations established by the New Source Performance Standards (NSPS). However, changes in the application of New Source Performance Standards that would mandate the use of flue-gas desulfurization equipment capable of removing 90 percent of released sulfur dioxide (SO_2) on all new plants regardless of the sulfur content of the burned coal would sharply curtail the demand for western coals as higher sulfur "local" coals would not have to be transported as far to the powerplant site. This effect is most dramatic in the case of midwestern coals. A partial list of factors influencing coal usage appears below.

Major Factors Influencing Coal Usage

Factors affecting the level of usage:

- Rate of growth of national energy consumption (especially electricity).
- Costs of competing fuels (especially imported oil and uranium).
- Distribution of electricity demand over time (peak vs. average power demand).
- Availability of capital, equipment, and mining manpower for expansion of mining capacity.

Factors affecting the distribution of usage:

- Regional differences in energy demand growth.
- Emission l imitations on sulfur oxides.
- Regional differences in costs of competing fuels.
- Rate of retirement of oil- and gas-fired powerplants.
- Relative costs of surface and deep mining.
- Availability and costs of transportation.
- Innovations in combustion and pollution-control technologies.
- Federal and State policies toward further development of coal reserves in the West.

Coal Sources

The model recognizes nine coal supply regions, listed in table 2, and three types of coal: bituminous, sub-bituminous, and lignite. Figure 3 is a map displaying the areas within the regions which are currently being mined or which are likely to be mined in the foreseeable future.

Table 2. Coal Supply Regions

Supply region	Code	States encompassed
1. **Northern Appalachia** . .	**NA**	**PA, MD, OH**
2. **Central Appalachia** . . .	**CA**	**WV, VA, KY (east)**
3. **Southern Appalachia.** .	**SA**	**TN, AL**
4. **Interior Eastern.**	IE	IN, IL, KY(west)
5. **Interior Western**	**IW**	**IA, KS, MO, OK,AR**
6. **Northwestern**	**NW**	**MT, ND**
Central Western	**CW**	**WY, UT, CO**
8. **Southwestern.**	**SW**	**AZ, NM**
9. **Texas.**	**TX**	**TX**

Source: Teknekron, Inc., *Projection of Utility Coal Movement Patterns: 1980-2000,* 1977.

Utility Simulation Model

This model simulates the response of the electric utility industry to postulated energy demands, economic conditions, and environmental regulations— the complete set of which specify a “scenario’’ -on a national scale. Eight scenarios were executed to provide insights into the sensitivity of the model to changes in variables and to reflect improvements brought about during the course of the assessment. One was selected as the basis for market assumptions in the subsequent economic analysis. Details of the model and the results of all of the scenarios are presented in Volume II, and what follows are the salient features and assumptions along with the selected set of results.

Coal Assignments

Coal is assigned to each generating unit on the basis of least cost to the utility, taking into account applicable sulfur-emission standards, coal heating and sulfur content, and mining and transportation costs. Four categories of available coals are assigned to each State. Three of the categories are the least expensive coals available to the State that can meet applicable sulfur-emission requirements without the use of flue-gas desulfurization. The emission limitations are specified for these three categories according to: 1) applicable State Implementation Plan (SIP) limitations for nonmetropolitan areas, 2) applicable State Implementation Plan limitations for metropolitan areas, and 3) emission limitations for new units under New Source Performance Standards (NSPS). The fourth category of coal is simply the least expensive coal available to the State without regard to its sulfur content. The actual assignment is made in a two-step procedure.

Figure 3–Coal Supply Regions

NORTHWESTERN
(NW)

CENTRAL WESTERN
(CW)

NORTHERN
APPALACHIA
(NA)

INTERIOR
EASTERN
(IE)

CENTRAL
APPALACHIA
(CA)

INTERIOR
WESTERN
(IW)

SOUTHERN
APPALACHIA
(SA)

SOUTHWESTERN
(SW)

TEXAS
(TX)

Source Tekoekron Inc

First, the sulfur-emission limitation in effect is determined for each unit depending on its location and the year that it went into service, Secondly, costs are compared to determine if it is more economical to burn the appropriate low sulfur coal without additional cleanup or to use flue-gas desulfurization equipment with the cheapest coal available. All coal-fired units within a given State that are subject to the same sulfur-emission limitations burn the same kind of coal, Neither blending of coals from different supply regions nor cleaning of significant amounts of coal are considered. Table 3 identifies the assigned coals in each of the four categories for each State by class, sulfur content, and delivered price, The class of the assigned coals are identified by the two letter code for the region of origin (see table 2 for codes), rank (bituminous (B), sub-bituminous (S B), or lignite (L)), and whether they are cleaned (C) or uncleaned (UC). Thus for example, the concatenated designation "SA/B/UC" for the nonmetropolitan SIP complying coal for Alabama specifies a Southern Appalachian, bituminous, uncleaned coal. This assignment procedure, which identifies only one coal source for a given State and set of environmental restrictions, represents an important limitation. It causes the model to predict large concentrated flows of coal from single producing areas to consuming States, so individual results at the State level are not as reliable as hose corresponding to larger regions,

Coal Prices

The prices developed in table 3 are expressed in 1975 dollars and are composed of three major elements. These include an f.o.b. mine raw coal price, a transportation cost from the region of origin to the State of consumption, and an additional component representing localized severance taxes or market premiums. The f.o.b. mine prices used as a base are calculated from National Economic Research Associates (N ERA)[1] data and con-

[1] National Economic Research Associates, Inc , Costs *of SO_x Control for the Steam Electric Power Industry,* June 1975

Table 3. Assigned Coals, by State, "No Cleaning" Scenarios (1975)

	Non metropolitan SIP complying coal			Metropolitan SIP complying coal			NSPS complying coal			Cheapest available coal		
State	Class	Sulfur (percent)	Price (cents/ 10° Btu)	Class	Sulfur (percent)	Price (cents/ 10°Btu)	Class	Sulfur (percent)	Price (cents/ 10° Btu	Class	Sulfur (percent)	Price (cents/ 10° Btu
Alabama. .,	SA/B/UC	1.7	51.3	CA/B/UC	1.2	93.7	CW/SB/UC	0.64	80.7	SA/B/UC	1.7	51.3
Arizona. ., ...	SW/SB/UC	0.6	27.2				SW/SB/UC	0.73	27.2	SW/SB/UC	0.87	27.2
Arkansas . . . . .,	SA/B/UC	1.3	65.0				CW/SB/UC	0.64	65.1	IE/B/UC		63.0
California.	CW/SB/UC	0.95	63.0	CW/SB/UC	0.5	63,0	CW/SB/UC	0.64	63.0	CW/SB/UC	0.95	63.0
Colorado	CW/SB/UC	0.85	42.8				CW/SB/UC	0.64	42.8	CW/SB/UC	0.95	42.8
Connecticut .,		None			None			None		NA/B/UC	2.5	68.5
Delaware . . . .,	NA/B/UC	3.0	65.5	CA/B/UC	1.0	61.1		None		NA/B/UC	3.0	68.0
Florida ... ., ., .,		None			None			None		SA/B/UC	1.7	75,8
Georgia . . . ., .,	IE/B/UC	3.0	62.6	IE/B/UC	3.0	62.6		None		IE/B/UC	3.6	62.6
Idaho	CW/SB/UC	1.0	36.2				CW/SB/UC	0.64	36.2	CW/SB/UC	1,0	36.3
Illinois . . . . .,	IE/B/UC	3.6	541	CW/SB	0.96	63.0	CW/SB/UC	0.64	63.0	IE/B/UC	3.6	54.1
Indiana. . . . ., .	CW/SB/UC	0.64	69.5				CW/SB/UC	0.64	69.5	IE/B/UC	3.6	54.1
Iowa ., ., ...	IE/B/UC	3.0	59.8				CW/SB/UC	0.64	56.3	IW/B/UC	3.7	52.6
Kansas, . . .	CW/SB/UC	0.95	51.8				CW/SB/UC	0.64	51.8	CW/SB/UC	0.95	51.8
Kentucky. .,	CA/B/UC	2.2	51.3	CA/B	0.77	65.8	CA/B/UC	0.77	65.8	IE/B/UC	3.6	54.3
Louisiana. ., ...	SA/B/UC	1.7	65.0	SA/B/UC	1.7	65.0	CW/SB/UC	0.64	78.3	SA/B/UC	1.7	65.0
Maine. ., . . .	NA/B/UC	2.5	80.2	NA/B/UC	2.5	80.2		None		NA/B/UC	2.5	80,2
Maryland	CA/B/UC	1.0	58.5	CA/B/UC	1.0	58.8		None		NA/B/UC	2.5	53.9
Massachusetts.		None			None			None		NA/B/UC	2.5	71.3
Michigan	NW/SB/UC	0.73	78.5				NW/SB/UC	0.64	78.5	IE/B/UC	3.7	66.5
Minnesota. .	NW/SB/UC	0.73	56.3	NW/SB/UC	0.73	56.3	NW/SB/UC	0.64	56.3	NW/SB/UC	0.73	56.3
Mississippi	SA/B/UC	1.7	59.5	SA/B/UC	1.7	59.5	CW/SB/UC	0.64	78.3	SA/B/UC	1.7	59.5
Missouri, ., ...	CW/SB/UC	1.2	63.0				CW/SB/UC	0.64	63.0	IW/B/UC	37	36.1
Montana . . .,	NW/SB/UC	0.73	31.7				NW/SB/UC	0.64	31.7	NW/SB/UC	0.73	31,7
Nebraska.	CW/SB/UC	0.95	40.8				CW/SB/UC	0.64	40.8	CW/SB/UC	0.95	40.8
Nevada. ., ., ., . .		None					CW/SB/UC	0.64	49.8	CW/SB/UC	0.95	49.8
New Hampshire . .	NA/B/UC	1.8	68.5	NA/B/UC	18	68.5		None		NA/B/UC	2.5	68.5
New Jersey	CA/B/UC	10	77,0		None			None		NA/B/UC	5.6	62.6
New Mexico . . .	SW/SB/UC	0.87	32.6				SW/B/UC	0.77	50.8	SW/SB/UC	0.87	31.2
New York. . . .	CA/B/UC	1.6	80.0		None			None		NA/B/UC	2.5	62.6
North Carolina . .	CA/B/UC	1,0	72.5	CA/B/UC	10	72.	CA/B/UC	0.64	89.5	CA/B/UC	2.1	72.5
North Dakota.	NW/L/UC	1,0	30.9				NW/SB/UC	0.64	44.6	NW/L/UC	1.1	0.9
Ohio : : : : :	NA/B/UC	2.6	54.1	CW/SB/UC	0.64	78.3	CW/SB/UC	0.64	78.3	NA/B/UC	3.7	54.1
Oklahoma	CW/SB/UC	1.1	58.3				CW/SB/UC	0.64	58.3	IW/B/UC	3.7	57.0
Oregon. ., .,	NW/SB/UC	0.73	65.3	NW/SB/UC	0,73	65.3	NW/SB/UC	0.64	65.3	NW/SB/UC	0.73	65.3
Pennsylvania, .,	NA/B/UC	2.4	54.1					None		NA/SB/UC	2.5	54.1
Rhode Island		None			None			None		NA/B/UC	2.5	68.5
South Carolina .,	SA/B/UC	1.7	621	SA/B/UC	1.5	62.1		None		SA/B/UC	1.7	62.1
South Dakota	CW/SB/UC	0.95	33.1				CW/SB/UC	0.64	33.1	CW/SB/UC	0.95	33.1
Tennessee.	SA/B/UC	1.7	53.9	CW/SB/UC	0.64	77.2	CW/SB/UC	0.64	77.2	SA/BUC	1.7	539
Texas,	TX/L/UC	1.2	43.3				CW/SB/UC	0.64	74.0	TX/L/UC	1.2	43.3
Utah.	CB/SB/UC	0.95	38.7				CW/SB/UC	0.64	38.7	CW/SB/UC	0.95	38.7
Vermont.		None			None			None		NA/B/UC	2.5	68.5
VlrgInia	CA/B/UC	17	51.1					None		CA/B/UC		51.1
Washington. .	NW/SB/UC	073	59.0	NW/SB/UC	073	60.0	NW/SB/UC	0.64	59.0	NW/SB/UC	0.73	59.0
W. Virginia	CA/B/UC	14	51.3	CA/B/UC	1.0	51.3	CA/B/UC	077	66.0	CA/B/UC	2.1	51.3
Wisconsin	IE/B/UC	3.6	63.0				NW/SB/UC	064	65.3	IE/B/UC	3.6	25.1
Wyoming, . ..		None					CW/SB/UC	064	25.1	CW/SB/UC	0.95	25.1

Notes: No entries under "Complying Met SIP" means there is only one is available, Sulfur content "as fired". Prices in 1975 dollars,
SIP in that State, arbitrarily considered to be non-met "NONE" means Sources: Teknekron, Inc. *Projections of Utility Coal* Movement *Patterns*
the limitation is so stringent that no coal which can meet it without FGD 1980-2000.

verted to 1975 dollars. The transportation cost is based on an assumed straight-line distance and a transportation rate as described below. A severance tax of 30 percent of f.o.b. mine price is added to the price of Montana coals (NW/SB class). A premium ("economic rent" of $0.15/106 Btu) is added to the delivered price of Appalachian coals complying with emission limitations equivalent to, or more stringent than, the New Source Performance Standards.

Time-dependent feedback relationships between the prices of coal and oil and rates at which the utilities use these fuels are not included in the analysis. Regional difference in coal prices, heating value, and sulfur content are accounted for in all the scenarios but an unlimited supply of coal at current (real) prices is assumed.

Coal Transportation

The model entails no constraints on the transport of coal. Transport costs were calculated by multiplying the straight-line distance from the center of the relevant supply region to the center of the consuming State by generalized transportation tariffs developed by NERA[2] (0.8 cents per ton-mile for coal originating in the West, 1.2 cents for coal originating in the Midwest and East).

Generating Mix

All existing generating units of investor-owned utilities, including nuclear, hydro, and fossil-fuel fired units are included in the data base, as are plants of the Tennessee Valley Authority (TVA) and municipal systems in Nebraska. Excluded utilities owned by public agencies amount to 15 percent of total generating capacity. New units currently planned by the industry for the period 1975-85 are also included, except that they are not brought "online" until the model determines that they are needed. If assumed electricity demand growth rates are lower than those implied by the utilties' plans filed with the Federal Power Commission (FPC), the model defers the startup date for an announced plant by one or more years beyond that indicated by the utility. The model sites new plants beyond 1985 (or later in the cases where new announced plants have been deferred), with the mix between coal and nuclear specified exogenously.

Demand for Electricity

Starting with actual electricity sales in 1973, a national average growth in peak and average power demand is specified exogenously to the model. This average rate is made to vary by region of the country to reflect normalized variations in population growth rates. Average power-demand growth is 5.4 percent per year in the selected scenario, while growth in peak demand is 5.9 percent per year.

Scenario Description

Energy Alternatives

Each energy alternative specifies both Government energy policy and the utilities' response to that policy by expressing the following factors quantitatively:

- Energy Policy
  - — Influence of Government management of supply and demand.
  - –Availability and price of fuels.
  - – Regulations for powerplant fuel conversions.
  - — Effect of natural gas curtailment.
- Utility Response
  - –Schedule for additions to capacity by fuel type and State.
  - –Schedule for conversions of gas- and oil-fired plants to coal.

The principal elements combined to specify a given alternative are the effect of Government demand-management policies on the rate of growth in demand for electricity, the additions to capacity by fuel type to meet demand and the oil-to-coal, gas-to-coal, and gas-to-oil conversions to be carried out. Under the selected scenario, the growth rates of 5.4 and 5.9 percent for average and peak demand reflect no Government policy for demand management.[3] Fuel mixes for capacity additions are those forecast by the nine regional reliability councils.

Coal prices have been discussed earlier, but the model includes other fuels as well. Oil prices are assumed to remain constant in real terms, while natural gas prices rise from current values to the Btu-equivalent price of oil in 1981, as reflected by current trends. Uranium prices are formed from a complex projection of utilities' current contracts and the estimates of future uranium prices, resulting in a significant rise in (real) price into the 1990's.

The curtailment of natural gas, in both the interstate and intrastate markets, significantly affects the future of the electric utility industry in the primary gas-burning States.[4] The industry must replace the curtailed capacity by

[2] Ibid

[3] Federal Energy Administration, National Energy Outlook, February 1976

[4] Texas, Oklahoma, Louisiana, Kansas, Florida, and California (Texas alone burned 45 percent of all 1975 gas deliveries to steam-electric plants Louisiana was second with 11 percent)

utilizing existing alternative fuel-burning capability, by rebuilding boilers to burn oil or coal, or by building additional new capacity over that which would be built without natural gas curtailments. All the energy alternatives incorporate the following set of plausible conditions:

1. All gas plants with only coal as an alternative capability burn coal.
2. Al gas plants with only oil as an alternative capability burn oil.
3. Gas plants that can burn either coal or oil switch to these fuels in proportion to current consumption of coal and oil by powerplants in the affected State.
4. All gas plants with no alternative firing capability burn gas until 985 and then are gradually phased out over the 10-year period from 985 to 1995.

The last category includes 32 percent of the Nation's gas plants and 40 percent of the Texas, Louisiana, Oklahoma, and California gas capacity. This degree of curtailment agrees closely with utility plans filed with the FPC.

Additions to generating capacity in the selected scenario are an extension of currently scheduled additions to generating capacity as shown in table 4, disaggregated by Electric Reliability Council region. The regions are illustrated in figure 4. A more detailed examination of the schedule for fossil-fueled steam capacity shows a breakdown into 80.9 percent coal-fired, 17.5 percent oil-fired, and 1.6 percent gas-fired, with all the gas-fired capacity scheduled to come online by the end of 1978. For simplicity in scheduling out to later years, the apportionment of new fossil steam capacity is 81 percent coal and 19 percent oil.

The utilities have also reported their intentions to add capacity in the decade from 1986 through 1995. These data, also obtained from the nine National Electric Reliability Councils, are summarized in table 5. Since the data were not further broken down, the same 81 percent coal/19 percent oil split in these fossil-fueled steam generation units is assumed.

Considering only the steam capacity planned after 1985, the division between coal, oil, and nuclear in capacity additions is approximately as follows:

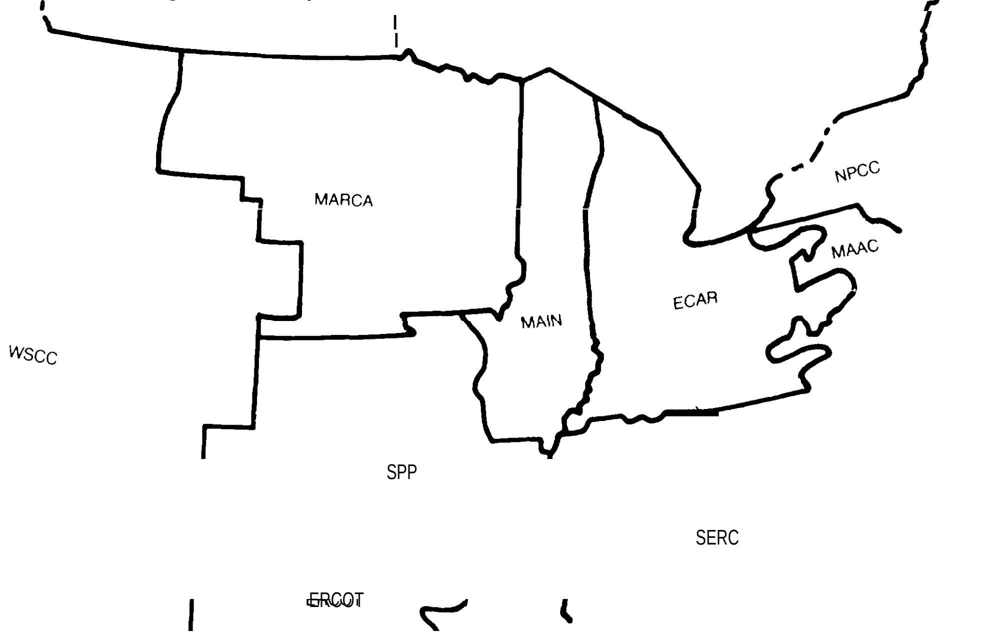
- Coal . . . 33 percent
- Oil . . . . . 8 percent } Fossil = 41 percent
- Nuclear. . 59 percent

Table 4. Scheduled Additions to Capacity, for the Decade 1976-85, as of April 1,1976, as Reported by Nine Regional Reliability Councils

Council	Total additions (MW)	Nuclear MW	Nuclear %	Fossil MW	Fossil %	Hydro, other MW	Hydro, other %
NPCC. . .	26,137	20,043	76.7	4,175	16.0	1,917	7.3
MAAC . .	21,863	16,755	76.7	5,079	23.2	28	0.1
ECAR. . .	42,461	19,743	46.5	22,582	53.2	136	0.3
SERC . . .	72,021	49,997	69.4	18,761	26.0	3,262	4.5
MAIN . . .	22,987	13,266	57.7	8,386	36.5	1,335	5.8
SWPP. . .	34,752	12,255	35.3	20,851	60.0	1,644	4.7
ERCOT. .	17,739	4,945	27.9	12,433	70.1	360	2.0
MARCA .	13,968	2,396	17.1	11,316	81.0	254	1.8
WSSC . .	53,918	23,330	43.3	18,738	34.7	11,849	22.0
Totals	305,846	162,730	53.2	122,321	40.0	20,785	6.8

Source: National Electric Reliability Council.

Figure 4—Regional Reliability Councils of the National Electric Reliability Council



Source Teknekron Inc

Table 5. Planned Additions to Capacity for the Decade 1986-95, as of April 1,1976, as Reported by Nine Regional Reliability Councils

Council	Total additions (MW)	Nuclear MW	Nuclear 0/0	Fossil MW	Fossil %	Hydro, other MW	Hydro, other 0/0
NPCC. . .	37,710	28,954	76.8	3,175	8.4	5,581	14.8
MAAC . .	31,545	16,173	51.3	14,299	45.3	1,073	3.4
ECAR . . .	86,500	44,115	51.0	39,790	46.0	2,595	3.0
SERC . . .	35,021	19,927	56.9	11,172	31.9	3,922	11.2
MAIN . . .	51,570	28,234	55.0	23,336	45.0	0	0
SWPP. . .	75,844	40,752	53.7	35,090	46.3	0	0
ERCOT. .	44,000	23,900	54.3	19,220	43.7	880	2.0
MARCA .	18,591	8,180	44.0	9,760	52.5	651	3.5
WSCC . .	85,000	50,065	58.9	24,055	28.3	10,880	12.8
Totals	465,781	260,300	55.6	179,897	38.6	25,582	5.5

Source: National Electric Reliability Council.

All post-1985 steam capacity is assigned in the above proportion and the mix of capacity planned to 1985 remains unaltered.

A coal conversion plan for existing and announced fossil steam units embodied in the selected scenario is as follows:

- Federal Energy Administration (FEA) conversion orders under the Energy Supply and Environmental Coordination Act (ESECA), for the conversion of oil and gas plants to coal plants, are not approved by E PA, and no such conversions take place.
- Gas plants that can convert only to coal do **SO.**
- All new oil-fired fossil steam units coming online after 1980 burn oil.
- Gas plants that can burn either coal or oil switch to these fuels in proportion to the consumption of coal and oil by powerplants in the affected State.

In summary, the energy alternative represented by the selected scenario is a relatively high demand, high nuclear one, particularly in the years beyond 1985. The high rate of demand growth and the low proportion of coal to nuclear plants tend to balance each other to produce an intermediate projection of coal use. A recapitulation of the main energy features of the scenario follows.

- Growth in demand for electric energy
  — 5.4 percent per year
- Growth in peak power demand
  — 5.9 percent per year
- Additions of new steam capacity after 1985
  –33 percent coal
  –8 percent oil
  —59 percent nuclear
- Conversion policy
  – FEA conversion orders under ESECA, for the conversion of oil and gas plants to coal plants, are not approved by EPA and no such conversions take place.
  –Gas plants that can convert only to coal do **SO.**
  —All new oil-fired fossil steam units coming online after 1980 burn oil.
  —Gas plants that can burn either coal or oil switch to these fuels in proportion to the consumption of coal and oil by powerplants in the affected State.

Environmental Alternatives

When incorporated into a scenario, each of several environmental policy alternatives will elicit a different response from the utilities, because of the intimate relationship between regulation and the behavior of the industry. The alternatives considered emphasize limitations on emissions from coal-fired plants as well as plant-siting restrictions. Utility response concerns the type of coal used, the pollution-control strategy employed, and the location of the post-1985 plants.

The chosen scenario illustrates the impact of a Non-Significant Deterioration (NSD) policy reflecting recent amendments to the Clean Air Act. This alternative is characterized by a restrictive siting policy and by one interpretation of what constitutes Best Available Control Technology (BACT). Siting is prohibited in areas where deterioration of air quality cannot be tolerated (for example, national parks and other Federal lands) and in nonattainment areas. Flue gas desulfurization (FGD) is required for all new coal units online after 1981. Assumed policy instruments include:

- Current State implementation plans.
- Current New Source Performance Standards.
- Siting prohibited in Class I and nonattainment areas. Since siting is not allowed in any county that contains any part of a Class I area, a significant land area is proscribed for development.
- For new sources online after 1981, BACT is required for $S0_2$. This is interpreted to mean mandatory FGD with 90-percent removal efficiency.

The policy of nonsignificant deterioration is designed to prevent the deterioration of air quality in those regions now cleaner than required by the National Ambient Air Quality Standards. The recent Clean Air Act amendments have the same goal. Area descriptions relating to NSD requirements considered in this analysis are as follows:

- Mandatory Class I if area exceeds 5,000 acres
  - — national and international parks
  - — national wilderness areas and wildlife refuges
- Class I with provision for redesignation as Class I I
  - — national monuments, recreational areas, wild and scenic rivers
- Class I I with provision for redesignation to Class I
  - — national preserves, forests, reservations, and other Federal lands

All mandatory or discretionary Class I areas are considered Class I in the Utility Simulation Model. The model's smallest resolution is at the county level; hence, any county containing any Class I area is designated a Class I county. In this scenario, the siting of fossil-fuel powerplants in Class I counties is prohibited, even though a small plant might be permitted by the increment of deterioration allowed.

In selecting a site for a new plant a utility makes a difficult decision, taking into account the distance to load center, costs of fuel and electricity transmission, availability of water and labor, and siting restrictions for environmental reasons, There are conflicting criteria for siting. Remote siting may be required to remove the source from a polluted area with a high population density, while regulations to prevent the significant deterioration of air quality exert pressure for siting away from clean areas toward areas having greater population density.

Remote siting has been an important alternative for coal. Typically, transportation accounts for a very significant fraction of the cost of coal delivered to the utility. Location near the mine, with long transmission lines, has proved cost effective in some cases. Projections of future costs of transport indicate an increased tendency toward remote siting. On the other hand, nonsignificant deterioration proposals would constrain both the number of available sites and the maximum size of a fossil-fueled plant. Taking all considerations into account leads to two different siting constraints:

- Siting of new (post-1985) fossil-fueled plants conforms to NSD regulations. Transmission costs, transportation costs, availability of water, and suitability of terrain are taken into account only in Class II areas. No siting is allowed in Class I counties, because the allowed air quality increments are too small to support an economically sized generation facility. A Class I county is a county having anywhere within its boundaries a Class I area as specified by the proposed amendments,
- Siting of new (post-1 985) plants is prohibited in areas where primary NAAQS for sulfur oxides, nitrogen oxides, or total suspended particulate are currently exceeded.

Results

The projections generated by the model under the selected scenario approximate an average annual compound growth rate for utility steam coal consumption of 4.2 percent. The total volume is projected to be 942 million tons in the year 2000 compared with actual deliveries to electric utilities of 429 million tons in 1975. Before 1985, the projection is consistently lower than those of several other studies, due to three major causes. One is the exclusion of some noninvestor-owned utilities, which accounted for 27 million tons of coal in 1974. Another is the use in this study of electric power demand growth instead of announced additions to generating capacity as a realistic determinant of future fuel use. The last causes a reduced rate of assumed growth based on recent experience as opposed to historical averages.

Levels of projected coal production by region appear in table 6, and patterns of distribution from producing region to consuming States are detailed in table 7. Figures 5 through 9 are maps indicating those flows of more than 5 million tons per year which traverse distances over 200 miles. Pipeline transportation is unlikely to be economically competitive at lesser distances and volumes.

The results corresponding to the seven additional scenarios indicate that the magnitudes of the flows are quite dependent on assumed demand growth rates, and that the spatial distribution of the coal movements are highly sensitive to environmental regulation and transportation cost assumptions. Penetration of western coal into eastern markets, for example, is highly dependent on transportation costs and on BACT requirements. High transportation costs and BACT tend to reduce the use of western coal east of the Mississippi. Also, the fact that the model chooses only one source of coal for a State, given a set of environmental requirements and embodies no market price-adjustment mechanism, tends to reduce the realism of results at the individual State level. The coal flows presented are therefore only illustrative of a plausible overall national pattern, and embody a high degree of uncertainty.

Table 6. Projected Regional Utility Coal Production

(Millions of tons per year)

Year	Appalachian (Northern, Central, and Southern)	Interior (Eastern and Western)	Western (North, Central, and South)	Total (Including Texas)
1975a	**208** “	**134**	**73** ‘	**429**
1980	**111**	**31**	**163**	**399**
1985	**224**	**64**	**223**	**523**
1990	**259**	**101**	**260**	**632**
1995	**297**	**133**	**324**	**772**
2000	**352**	**211**	**364**	**942**

[a] 1975 figures are actual. Differences in the distribution of production between 1975 and 1980 are due primarily to the assumption underlying the model that specified environmental regulations will be complied with by 1980.

Source: Derived from data in Teknekron, Inc.

Table 7. Projected Utility Coal Distribution From Region of Origin to State of End Use

(Millions of tons per year)

State	Year 1980	1985	1990	1995	2000
Alabama (total)	12	12	15	18	21
S. Appalachian	12	12	15	18	21
C. Western	0.20	0.10	0.03	—	—
Arizona (total)	2.7	0.44	0.34	0	0
S. Western	2.7	0.44	0.34	—	—
Arkansas (total)	0	1.6	3.4	7.0	8.4
I. Eastern	— ·	1.6	1.8	7.0	8.4
C. Western			1.6		
California (total)	0.91	9.2	14	31	39
C. Western	**0.64**	**8.9**	**14**	**31**	**38**
S. Western	**0.27**	**0.27**	—	—	**0.95**
Colorado (total)	**4.4**	**6.3**	**8.8**	**12**	**16**
C. Western	4.4	6.3	8.8	12	16
Connecticut (total)	0	1.1	0	0	0
C. Appalachian	—	1.1	—	—	—
Delaware (total)	1.2	1.0	1.2	1.1	0.96
C. Appalachian	1.2	1.0	1.2	1.1	0.96
C. Western	—	0.03	—	—	—
Florida (total)	8.8	16	21	22	32
S. Appalachian	**8.8**	**16**	**21**	**22**	**32**
Georgia (total)	**1.6**	**19**	**23**	**28**	**39**
I. Eastern	1.6	19	23	28	39
Idaho (total)	1.5	3.0	3,0	2.9	3.0
C. Western	**1.5**	**3.0**	**3.0**	**2.9**	**3.0**
Illinois (total)	**30**	**35**	**38**	**47**	**74**
I. Eastern	10	**16**	**22**	**31**	**58**
C. Western	**20**	**19**	**16**	**16**	**16**
Indiana (total)	**30**	**30**	**43**	**47**	**59**
I. Eastern	—	**5.3**	**18**	**28**	**42**
C. Western	**30**	**25**	**25**	**19**	**17**
Iowa (total)	**5.9**	**8.7**	**9.0**	**7.4**	**10**
I. Eastern	**5.9**	**4.7**	**4.1**	**3.3**	**2.7**
I. Western	—	**3.8**	**4.9**	**4.1**	**7.3**
Kansas (total)	**5.7**	**4.8**	**8.1**	**23**	**19**
I. Eastern	5.7	1.8	—	—	—
I. Western	—	3.0	3.6	—	—
C. Western	—	—	4.5	23	19
Kentucky (total)	23	23	25	29	34
C. Appalachian	**23**	**19**	**5**	**13**	
I. Eastern	—	**3.6**	**9.8**	**16**	**23**
Louisiana (total)	**0**	**8.5**	**9.4**	**14**	**16**
S. Appalachian	—	**1.5**	**8.3**	**11**	**16**
I. Eastern	—	**1.5**	**1.1**	—	—
C. Western	—	**5.5**	—	**3.5**	—

Table 7. Projected Utility Coal Distribution From Region of Origin to State of End Use—Continued

(Millions of tons per year)

State	Year				
	1980	1985	1990	1995	2000
Maine (total)	0	0	0	0	0
Maryland and D.C. (total)	3.6	6.2	5.6	12	14
N. Appalachian	3.4	5.8	5.1	12	14
C. Appalachian	0.13	0.30	0.40	—	
S. Appalachian	—	—		0.10	0.10
C. Western	0.10	0.10	0.10	0.03	0.03
Massachusetts (total)	0	0	0	0	0
Michigan (total)	25	29	26	26	30
I. Eastern	—	5.8	8.2	7.6	13
N. Western	25	23	18	17	17
C. Western	0.06	—	—	1.8	—
Minnesota (total)	5.4	11	14	16	17
N. Western	5.4	9.7	13	15	16
C. Western	—	1.2	1.1	1.1	1.0
Mississippi (total	3.8	4.9	6.1	10	13
S. Appalachian	3.8	4.9	6.1	10	13
Missouri (total)..	25	27	29	35	41
I. Western.	—	1.6	6,0	17	27
C. Western	25	25	23	18	14
Montana (total)	7.4	7.4	7.3	7.3	7.3
N. Western	**7.4**	**7.4**	**7.3**	**7.3**	**7.3**
Nebraska (total)	**5.2**	**5.2**	**5.2**	**5.2**	**5.2**
C. Western	5.2	5.2	5.2	5.2	5.2
Nevada (total)	6.5	7.4	9.8	7.5	3.9
C. Western	6.5	7.4	9.8	7.5	3.9
New Hampshire (total)	0.10	0.60	0.04	0.50	0.30
N. Appalachian	0.10	0.60	0.04	0.50	0.30
New Jersey (total)	1.5	1.3	1.0	1.0	2.5
N. Appalachian	0.52	0.32	—	—	1.5
C. Appalachian	1.0	1.0	1.0	1.0	1.0
New Mexico (total)	7.3	8.1	9.3	12	10
C. Western	—	—	—	—	**2.4**
S. Western	**7.3**	**8.1**	**9.3**	**12**	**7.9**
New York (total)	**3.8**	**3.5**	**8.8**	**8.8**	**11**
N. Appalachian	**1.9**	**1.8**	**7.2**	**7.6**	**8.3**
C. Appalachian	**1.9**	**1.7**	**1.6**	**1.2**	**2.6**
North Carolina (total)	**18**	**18**	**15**	**15**	**16**
C. Appalachian	18	18	15	15	16
S. Appalachian	0.31	—	0.10	0.01	0.07
North Dakota (total)	0.29	0.77	3.9	6.6	12
N. Western	0.26	0.76	3.9	6.6	12
C. Western	0.03	0.01	0.01	0.01	0.02

Table 7. Projected Utility Coal Distribution From Region of Origin to State of End Use—Continued

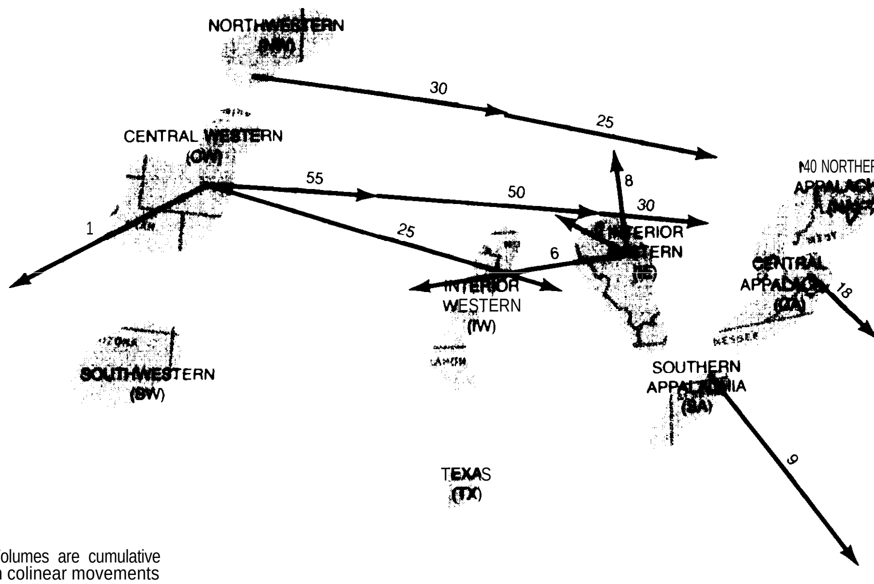
(Millions of tons per year)

State	Year 1980	1985	1990	1995	2000
Ohio (total)	45	48	43	48	48
N. Appalachian	43	47	42	47	47
C. Western	1.6	1.3	1.1	1.1	0.92
Oklahoma (total)	0.02	9.2	14	17	25
I. Western	—	9.2	14	17	25
C. Western	0.02	—	—	—	—
Oregon (total)	1.5	3.1	0.06	5.1	1.0
N. Western	—	—	—	0.9	1.0
C. Western	1.5	3.1	0.06	4.2	—
Pennsylvania (total)	37	36	55	59	67
N. Appalachian	33	32	50	57	67
C. Appalachian	4.0	3.6	4.9	1.9	—
Rhode island (total)	0	0	0	0	0
South Carolina (total)	1.9	2.0	1.7	1.2	1.2
S. Appalachian	1.9	2.0	1.7	1.2	1.2
South Dakota (total)	1.4	2.1	2.2	2.4	2.7
N. Western	1.4		1.4	1.4	—
C. Western	—	0.70	0.80	1.0	2.7
Tennessee (total)	19	8.8	7.0	2.8	0.96
S. Appalachian	19	8.8	7.0	2.8	0.96
Texas (total)	15	48	84	112	141
S. Appalachian	—	1.5	1.1	1.0	—
C. Western	1.3	35	72	93	125
S. Western	—	—	—	0.20	0.20
Texas	14	12	12	18	16
Utah (total)	3.2	4.0	2.0	8.0	18
C. Western	3.2	4.0	2.0	8.0	18
Vermont (total)	o	0	0	0	0
Virginia (total)	6.2	3.4	5.2	5.3	9.2
C. Applalachian	3.4	1.5	4.4	4.5	8.9
S. Applachian	2.8	1.90	0.80	0.80	0.30
Washington (total)	2.9	2.9	2.9	2.9	2.9
N. Western	2.9	2.9	2.9	2.9	2.9
West Virginia (total)	24	23	30	44	52
N. Appalachian	1.2	1.1	0.97	0.54	—
C. Appalachian	23	22	29	43	52
Wisconsin (total)	12	13	9.2	10	6.5
I. Eastern	7.5	9.3	5.9	6.9	3.5
N. Western	4,4	3.9	3.3	3.3	3.0
Wyoming (total)	4.4	10	12	9.8	12
C .Western	4.4	10	12	9.8	12

Source: Data from Teknekron, Inc.

NOTE: These projections are intended to illustrate a plausible overall national pattern and do not represent predictions that the coal volumes will be transported between the listed origins and destinations.

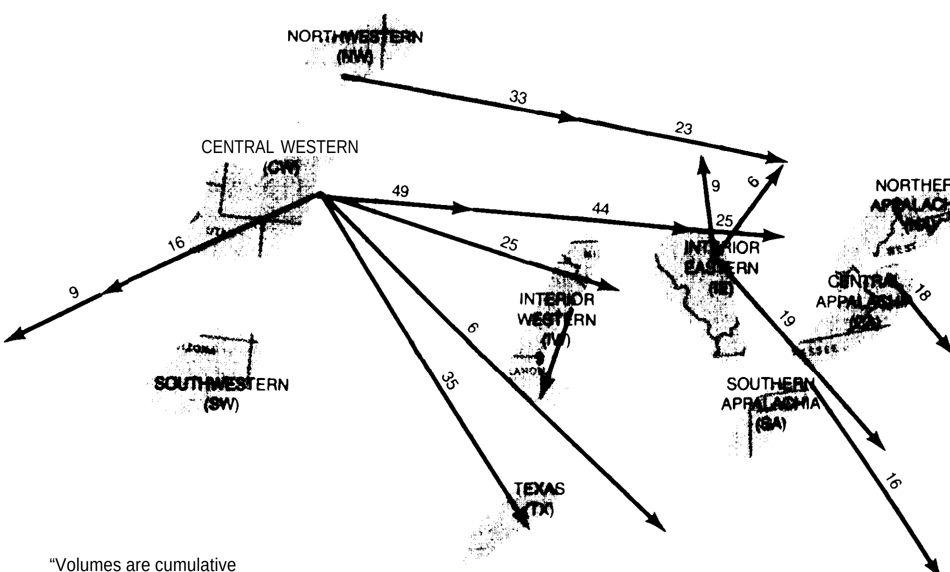
Figure 5–Year 1980 Potential Utility Coal Movements of More Than 5 Million Tons per Year over Distances Greater Than 200 Miles (Millions of Tons per Year)*



● Volumes are cumulative on colinear movements

Source Teknekron Inc

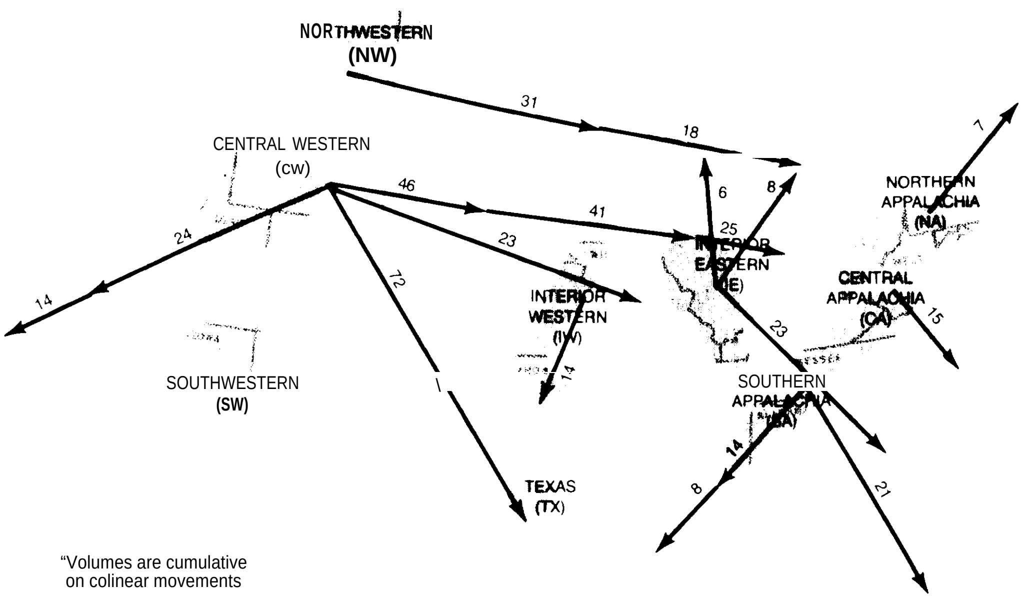
Figure 6–Year 1965 Potential Utility Coal Movements of More Than 5 Million Tons per Year over Distances Greater Than 200 Miles (Millions of Tons per Year)*



“Volumes are cumulative on colinear movements

Source Teknekron Inc

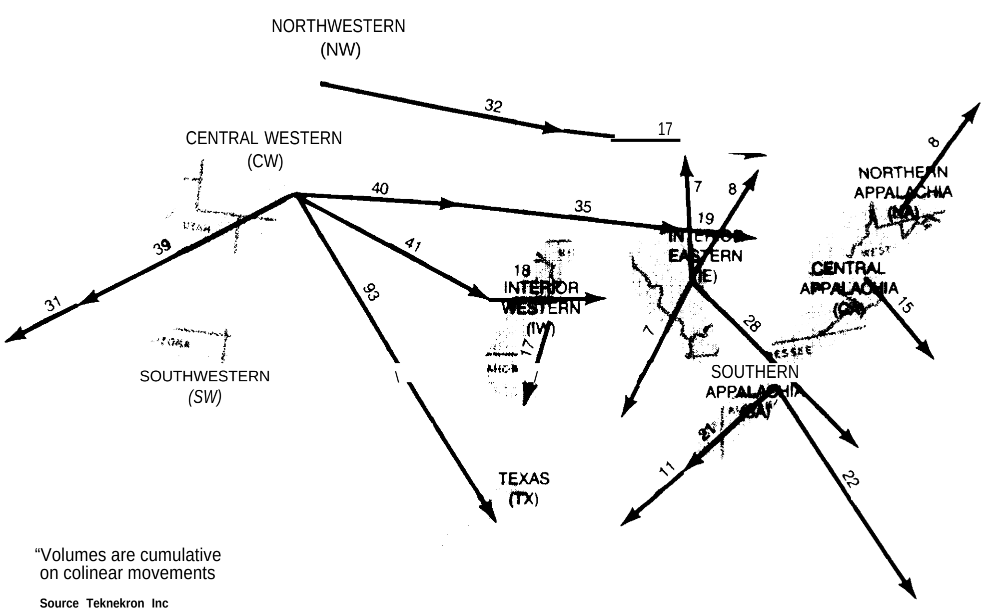
Figure 7–Year 1990 Potential Utility Coal Movements of More Than 5 Million Tons per Year over Distances Greater Than 200 Miles (Millions of Tons per Year)*



“Volumes are cumulative on colinear movements

Source Teknekron Inc

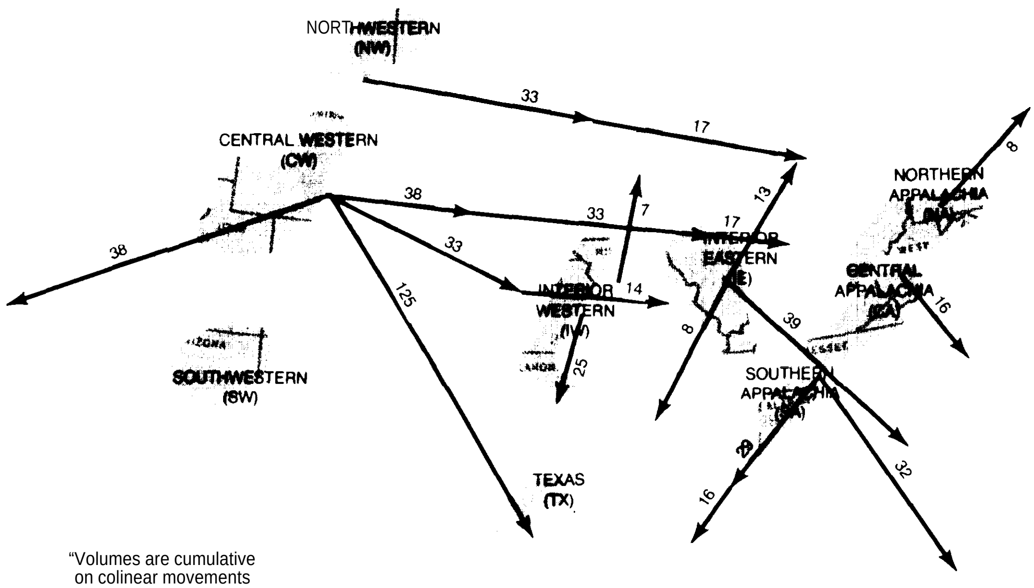
Figure 8– Year 1995 Potential Utilitv Coal Movements of More Than 5 Million Tons per Year over Distances Greater Than 200 Miles (Millions of Tons per Year)*



“Volumes are cumulative on colinear movements

Source Teknekron Inc

Figure 9–Year 2000 Potential Utility Coal Movements of More Than 5 Million Tons per Year over Distances Greater Than 200 Miles (Millions of Tons per Year)*



"Volumes are cumulative on colinear movements

Surce Teknekron Inc

COST COMPARISONS AND TRAFFIC ASSUMPTIONS

Comparison of the economic and environmental features of a world with slurry pipelines to another without them requires the establishment of plausible scenarios describing the nature of the transportation system in each case. The critical characteristics to be specified for each mode are cost and extent of operations. The world without pipelines involves a rail system which, with other present modes, would meet the hypothetical demand for utility coal transportation outlined in the last section. Under the other scenario, one envisions a hybrid rail and pipeline system which would carry projected traffic by the cheaper mode from the shipper's standpoint.

The second scenario is necessarily highly conjectural, depending not only on the simplified projections of the coal transportation market, but also on crude cost estimates and uncertain predictions of the behavior of transportation firms, their customers, and government regulatory bodies. However, the purpose of this section is to derive a plausible if arbitrary set of market share and cost assumptions that are sufficiently favorable to pipelines to provide a basis for comparison with a "no pipeline" alternative.

costs

Four hypothetical case studies, described in Volume 11, provide the focus for both the cost and environmental analyses of the assessment. Four coal flows from among those identified in the last section were chosen and arbitrarily assigned specific States of origin as follows:

1. Central Western coal from Wyoming to Texas,
2. Northwestern coal from Montana to Minnesota and Wisconsin,
3. Central Western coal from Utah to California.
4. Southern Appalachian coal from Tennessee to Florida

These four origin and destination pairs exhibit differences in a) region of the country, b) condition and circuity of the rail system, c) type of terrain, d) access to water, e) type and **concentration** of mining activity, and f) volumes of coal to be transported.

The costs considered here are incremental ones from the viewpoint of a railroad or pipeline enterprise, and they therefore represent the rates that a firm providing the transportation would have to charge its shippers in order not to lose money on the traffic in question They do not necessarily represent the rates that would be charged in the current regulatory environment, and they include neither profit beyond a minimum cost of capital for direct investment nor any contribution to the fixed costs of a larger railroad or pipeline system. The estimates presented also provide for no change in technology or productivity with time for either mode, and they reflect present, and therefore not necessarily ideal, conditions in the railroad industry. Finally, the costs derived for specific individual movements from engineering considerations as discussed below should not be confused with overall system costs, which include economies of scale and are covered in a later section on economic impacts.

Pipeline Estimating Procedure

To be comparable with rail costs, pipeline estimates here include the entire process of transporting coal from individual mines to powerplants, including collection and distribution by branch feeder lines, Requirements imposed upon a given pipeline by the nature of the application can be expressed in terms of the following factors:

1. Distance the coal must be carried.
2. Volume of coal to be carried,
3. Moisture content of the coal.
4. Difference between elevations of termini.
5. Terrain characteristics.
6. Distance to and elevation of the water Supply.
7. Size and spacing of mines.
8. Size and spacing of powerplants.

engineering design considerations, industrial experience, and data from equipment manufacturers form the basis for identifying and quantifying individual resource requirements as follows:

Initial construction:

1, Slurry preparation and dewatering equipment and facilities.
2. Pump stations, including pumps and lined ponds.
3. Steel pipe, including freight,
4. Right-of-way and pipe laying.
5. Engineering, supervision, inspection, and contingency.

Continuing Operation:

1. Direct Labor.
2. Power.
3. Maintenance, materials, and supplies.
4. Water.
5. Administration.

Cost estimates are derived by applying prices to the above elements, providing for inflation in the continuing operating costs, amortizing the required initial investment, and postulating a tax rate. The details of the methodology and the values used in the analysis are set forth in detail in Volume II, and figures 10 through 14 illustrate how the cost elements that are not site-dependent are related to the volume of coal to be carried, the distance to be covered, and the *required* number of pumping stations. One should note in interpreting the cost relationships, that the pump stations are assumed to operate against a given pressure difference of 1,000 pounds per square inch. Fewer stations are therefore required as the diameter of the pipe increases.

These costs have been adjusted in the case studies to account for acquisition of water and for nonideal construction conditions based on the particular characteristics of a pipeline application. Areas of particular uncertainty include future construction costs and the appropriate price for water.

Rail Estimating Procedure

Although operating experience for railroads is more extensive than for pipelines due to the longer history of the industry and its more established technologies, establishing the marginal, or out-of-pocket costs for a given element of hypothetical traffic is no more .straightforward. The factors determining rail costs for coal unit trains include the following:

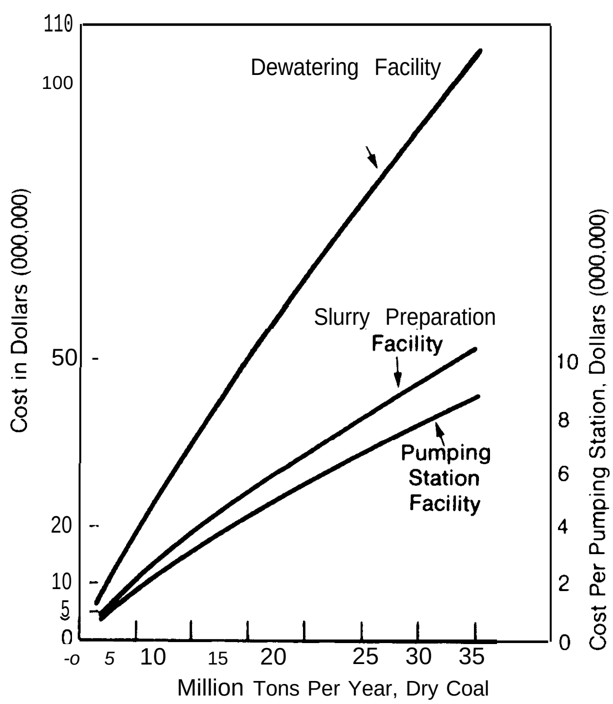
1. Distance the coal must be carried.
2. Volume of the coal to be carried.
3. Unused capacity and condition of tracks along the route.
4. Length and speed of trains.
5. Terrain and circuity of the route.
6. Administration.

The cost elements that do not depend on site-specific conditions appear below:

1. Acquisition of rolling stock —
   $550,000 per locomotive
   $30,000 per 100 net-ton hopper car
   $43,000 per caboose
2. Track improvement —
   $500,000 per mile of new track
   $200,000 per mile of upgraded track
3. Train crews (including dead heading)
   $550 per 100 train miles
4. Diesel fuel –
   $0.35 per gallon
5. Operation and maintenance of rolling stock —
   $0.44 per mile per year per locomotive
   $0.03 per mile per year per hopper car
   $002 per mile per year per caboose
6. Track maintenance per mile per year—
   $5,300 plus $342 per million tons of traffic
7. Administration —
   $0.30 per thousand ton-miles

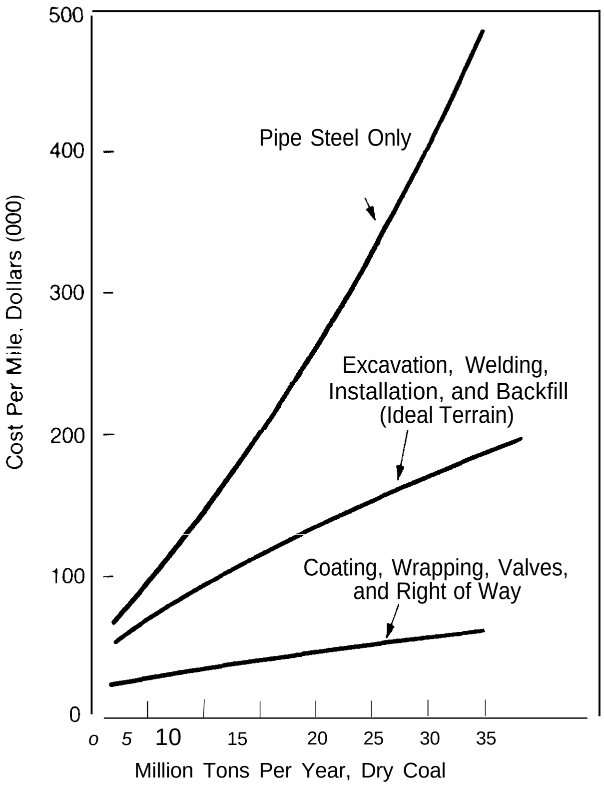
Acquisition and operating costs of loading and unloading facilities depend on site-specific conditions as do the amount of fuel and track upgrading required. The amount of track investment required for a particular traffic element is particularly uncertain, as is the degree to which other traffic should properly be charged for some of the cost of a given improvement. Also, railroad ownership of rolling stock has been assumed. If customers owned the hopper cars, they would pay a reduced transportation rate and would have to finance the acquisition and maintenance of the cars. Utilities often find this arrangement advantageous. Initial investment financing, inflation, and taxes are all treated in the same fashion as for pipelines, and the details of the methodology are also described more fully in Volume II.

Figure 10–Slurry Facility First Costs
(Including an 18 percent provision for engineering, inspection, and contingencies)



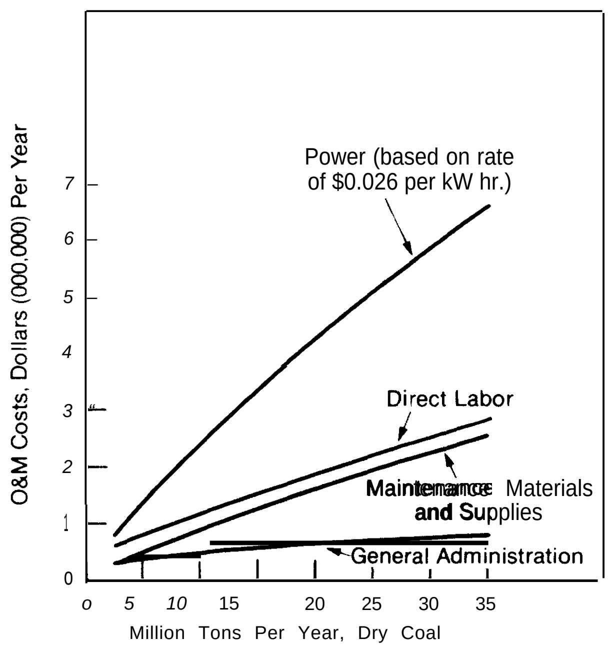
Source General Research Corp

Figure 11– Pipeline First Costs
(Including an 18 percent provision for engineering, inspection, and contingencies)



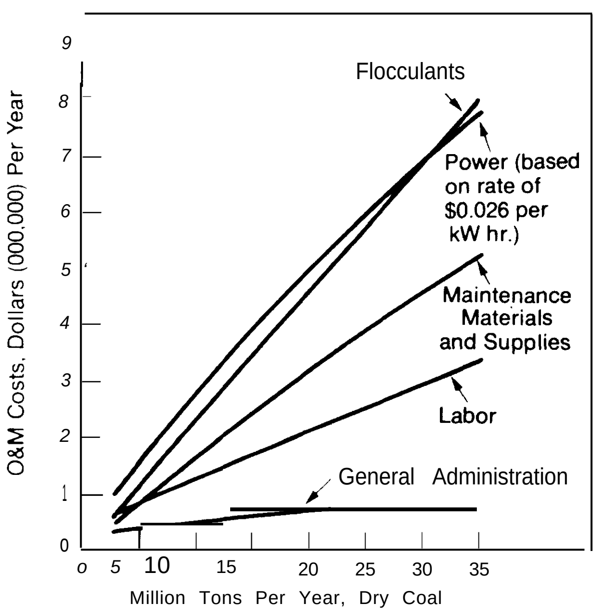
Source General Research Corp

Figure 12–Annual Operation and Maintenance Costs, Slurry Preparation Facility
(Excluding water)



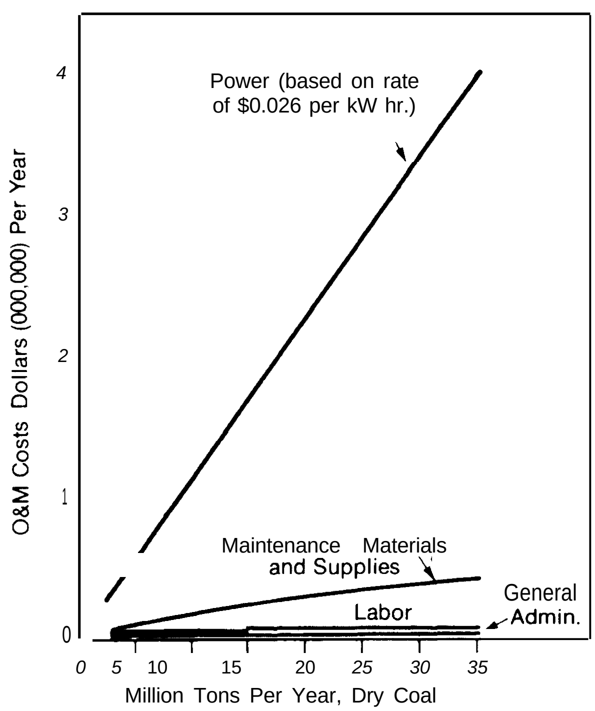
Source General Research Corp.

Figure 13–Annual Operation and Maintenance Costs, Slurry Dewatering Facility



Source General Research Corp

Figure 14–Annual Operation and Maintenance Costs per Pumping Station



Source General Research Corp

Selected Case Results and Discussion

Table 8 illustrates the comparative characteristics and costs of four specific coal flows by rail and pipeline. Pipeline transportation appears more economical in the Wyoming to Texas and Tennessee to Florida cases, and rail is less costly for both Montana to Minnesota and Wisconsin, and for Utah to California.

The Wyoming to Texas case illustrates the advantages of carrying a large volume of coal in a single pipeline over a great distance. The pipeline would be over 1,000 miles long and carry 35 million tons per year over most of its length. To achieve this scale requires that eight powerplants in two regions of Texas be served by the same pipeline, and the fact that only four mines near Gillette, Wyo., could produce the required volume contributes to the economy of operation.

Between Montana and the destinations in Minnesota and Wisconsin, the rail route is direct and in good physical condition. Train lengths of 105 cars and average speeds of 22 miles per hour, including stops for loading and unloading, also play a role in the rail cost advantage in this case, as does the railroad's flexibility to serve economically a relatively larger number of mines and powerplants for a given volume of coal.

The Utah to California case represents the least annual volume, the shortest distance, and the smallest mines served. It also represents the most difficult terrain for both pipeline construction and rail operation, and the advantage of trains is offset partially by their roughly 30-percent greater route circuity and the need to replace 25 percent of the present rail.

The only case east of the Mississippi, from Tennessee to Florida, illustrates that even though several mines and powerplants would have to be served and the rail route is not particularly circuitous, pipelines may be advantageous if rail operating conditions are significantly less than ideal. On this route, which is not necessarily typical of coal-producing areas, 35 percent of the track would have to be replaced or upgraded, and trains would be substantially shorter and slower than i n the other cases.

Other factors not mentioned above which influence the relative costs of unit trains and slurry pipelines include the expected rate of inflation in labor and operating costs of electricity and diesel fuel, and the cost of water delivered at the pipeline source. To oversimplify somewhat, the cost of unit train transportation of coal is roughly one-third amortization of investment in facilities and equipment and two-thirds operating expense, including labor. Pipeline costs, on the other hand represent nearly two-thirds initial investment and just over one-third continuing operation. Therefore, high rates of anticipated inflation favor pipelines over rail, while high real interest rates and labor productivity improvements have the opposite effect. The cost figures derived here are based on a 6-percent annual rate of inflation and a 61A-percent real interest rate, which added together, amount to a nominal discount rate of 1 21/2 percent.

Energy resource costs also influence the relative advantages of each mode. If one considers the fuel required to generate electricity, railroads and pipelines use roughly comparable amounts of energy directly to provide power for equipment. However at $0.35 per gal lon, diesel fuel represents typically about one-eighth of the cost of operating a coal unit train, while electricity at $0.026 per kilowatt hour amounts to approximately one-fifth of the cost of carrying the same coal by an equivalent-sized pipeline. Since the energy portion of the cost is substantial, increases in the cost of diesel fuel relative to that of electricity will improve the competitive position of pipelines, at least until electrification becomes advantageous to the railroads.

High water costs, on the other hand, can substantially weaken the competitive position of pipelines. Carrying 18 million tons of coal from Gillette, Wyo., to Dallas, Tex., for example, would require 8,554 acre-feet of water per year. If this amount were purchased for $20

Table 8. Sample Hypothetical Case Results

Characteristics	Wyoming to Texas	Montana to Minnesota & Wisconsin	Utah to California	Tennessee to Florida
General				
Volume (millions of tons per year) .,.	*35*	*13.5*	10	16
Origin Vicinity.	Gillette	Colstrip	Price	Tracy City
Destination vicinity	Dallas (18 million tons) Houston (17 million tons)	Becker, M inn. (10 million tons) Portage, Wise. (3.5 million tons)	Barstow	Tampa (8 millions tons) Miami (8 million tons)
Number of mines ., ., .	4	3	7	8
Number of powerplants	5 (Dallas) 3 (Houston)	3 (Becker) 2 (Portage)	3	3 (Tampa) 4 (Miami)
Pipeline				
Trunkline length	Gillette-Dallas, 936 miles Dallas-Houston, 234 miles	Colstrlp-Becker, 661 miles Becker-Portage, 260 miles	522 miles	Tracy City-Tampa 556 miles Tampa-Miami 247 miles
Average distance from mine to trunkline .	12,5 miles	10 miles	12.4 miles	20 miles (Tampa) 22 miles (Miami)
Percentage moisture of coal by weight	21 percent	17 percent	6.6 percent	4.8 percent
Water requirement in acre-feet per year.	16,640	7,250	6,961	11,580
Water source.	Big Horn River	Big Horn River	Green River	Lake Nickajack
Length of water line	205 miles	80 miles	42 miles	20 miles
Total cost of water delivered per acre-foot .	$922	$513	$469	$184
Number of pump stations	Gillette-Dallas 4 Dallas-Houston 3	Colstrip-Becker 8 Becker-Portage 8	7	Tracy City-Tampa 6 Tampa-Miami 4
Outside pipe diameter	Gillette-Dallas 42” Dallas-Houston 29”	Colstrip-Becker 27” Becker-Portage 14”	24”	Tracy City-Tampa 31” Tampa-Miami 22”
Present worth of 30-year life cycle cost (1977 dollars)	$2,502 million	$1,156 million	$996 million	$1,626 million
Annual cost per ton (1977 dollars at a 6.5-percent real cost of money) .	$5.50	$6.60	$7.60	$7.80
Simulated rate per ton (1977 dollars with a 12.5-percent nominal return on investment)	To Dallas $5.90 To Houston $6,50	To Becker $6.00 To Portage $10.80	$9.90	To Tampa $7.30 To Miami $9,70

Table 8. Sample Hypothetical Case Results—Continued

Characteristics	Wyoming to Texas	Montana to Minnesota & Wisconsin	Utah to California	Tennessee to Florida
Rail				
Average route length . .	Gillette-Dallas, 1,264 miles Gillette-Houston, 1,584 miles	Colstrip-Becker, 757 miles Colstrip-Portage, 1,055 miles	684 miles	Tracy City-Tampa 776 miles Tracy City-M i am i 938 miles
Number of cars per train . .	105	105	100	60
Average number of locomotives per train	6	Colstrip-Becker, 4.27 Colstrip-Portage, 4.19	6.2	3.9
Average round-trip speed (including time loading and unloading)	22 mph	22 mph	14.2mph	13mph
Average locomotive miles per gallon of fuel	0.4	0.29	0.38	0.33
Percentage of new track required . .	Gillette-Dallas, 5 percent Gillette-Houston, O percent	0 percent	25 percent	5 percent
Percentage of track to be upgraded	Gillette-Dallas 30 percent Gillette-Houston 20 percent	5 percent	10 percent	30 percent
Investment in loading and unloading facilities.	$174 million	$88 million	$64 million	$150 million
Annual operation of loading and unloading facilities. . .	$14 million	$7.0 million	$5.3 million	$9.3 million
Present worth of 30-year life cycle cost (1977 dollars).	$3,939 million	$1,059 million	$893 million	$1,930 million
Annual cost per ton (1977 dollars at a 6.5-percent real cost of money) . . .	$8.60	$6.00	$6.80	$9.20
Simulated rate per ton (1977 dollars with a 12.5-percent nominal return on investment) . . .	To Dallas, $8.70 To Houston, $9.10	To Becker, $5.40 To Portage, $8.40	$7.30	To Tampa, $9.00 To Miami, $10.50

Note: The ranges of uncertainty associated with these specific rail and pipeline cost estimates may be as large as the differences between them. For underlying simplifications and assumptions, see text at the end of this chapter. Also, the coal tonnages are for illustrative purposes only and do not represent predictions that the coal volumes will be transported by pipeline or any other mode between the listed origins and destinations.

Source. Data from General Research Corp.

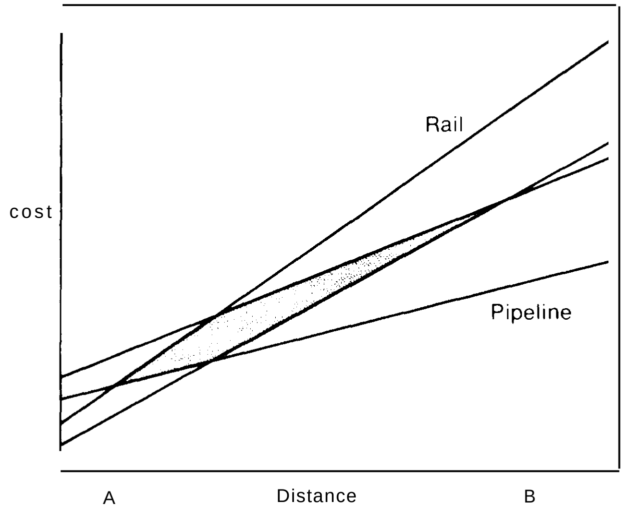
per acre-foot at Big Horn River and transported by pipe to Gillette, the total cost would be $922 per acre-foot, or $0.47 per ton of coal shipped. Of the total amount of water used, about 4,905 acre-feet could be extracted and recycled by return pipeline, raising the total water cost to $1 75 per ton of coal, Increases of this magnitude, whether due to economic competition for limited supplies of western water or to institutional requirements that water be recycled or obtained from distant or costly sources, will diminish the amount of coal traffic for which pipelines can compete effectively

The following list is a recapitulation of the principal factors influencing the relative costs of unit trains and slurry pipelines for coal transportation

1. Annual volume of coal
2 Distance to be traversed
3 Expec-ted rate of inflation
4 Real interest rate
5 Size and spacing of mines,
6 Presence of general large customers to receive coal
7 Terra in and excavation difficulty
8 Water availability and cost
9 Relative costs of diesel fuel and electricity.
10 Railroad track circuity and condition
11. Length and speed of trains.

The principal lessons from the foregoing analysis are that a) Slurry pipelines are more economical than unit trains some specific types of individual movements, and b) the comparative costs of the two modes do not lend themselves to easy generalization based on simple criteria The latter observation is illustrated by figure 15, which shows ranges of rail and pipeline costs for a given volume of coal as they vary typically with distance. The precise cost within the range is determined by the several factors other than volume and distance discussed above Note that the cost ranges overlap between distances A and B, and that one can only concude with confidence that rail will be least costly at distances less than A, and that a pipeline will be more economical at distances greater than B.

Figure 15– Form of Typical Rail and Pipeline Cost Ranges for a Given Annual Tonnage



Source Office of Technology Assessment

Some generalization is required to compare the case results with previous studies Figure 16 illustrates the results of an assortment of other coal Slurry pipeline cost calculations, and figure 17 shows the results of two other coal unit train studies for comparison. In interpreting the latter, one Should note that regulated tariffs are not always the same as costs, and that individual tariffs vary significantly from the values represented by the ICF regression lines

The results of the case analyses developed here appear in figure 18 Although the differences between any two sets of cost estimates are due in part to dissimilar underlying assumptions and procedures, the results of the studies taken together serve as additlonal evidence of the wide range of unncertainty associated with global generalizations about the relative costs of slurry pipelines and unit trains in specific applications.

Traffic Assumptions

Painting a plausible scenario for the purpose of evaluating the global economic effects, as opposed to the localized costs, of the development of a coal slurry pipeline industry required Ignoring one of the lessons of the cost analysis

Figure 16– Results of Previous Coal Slurry Pipeline Cost Studies

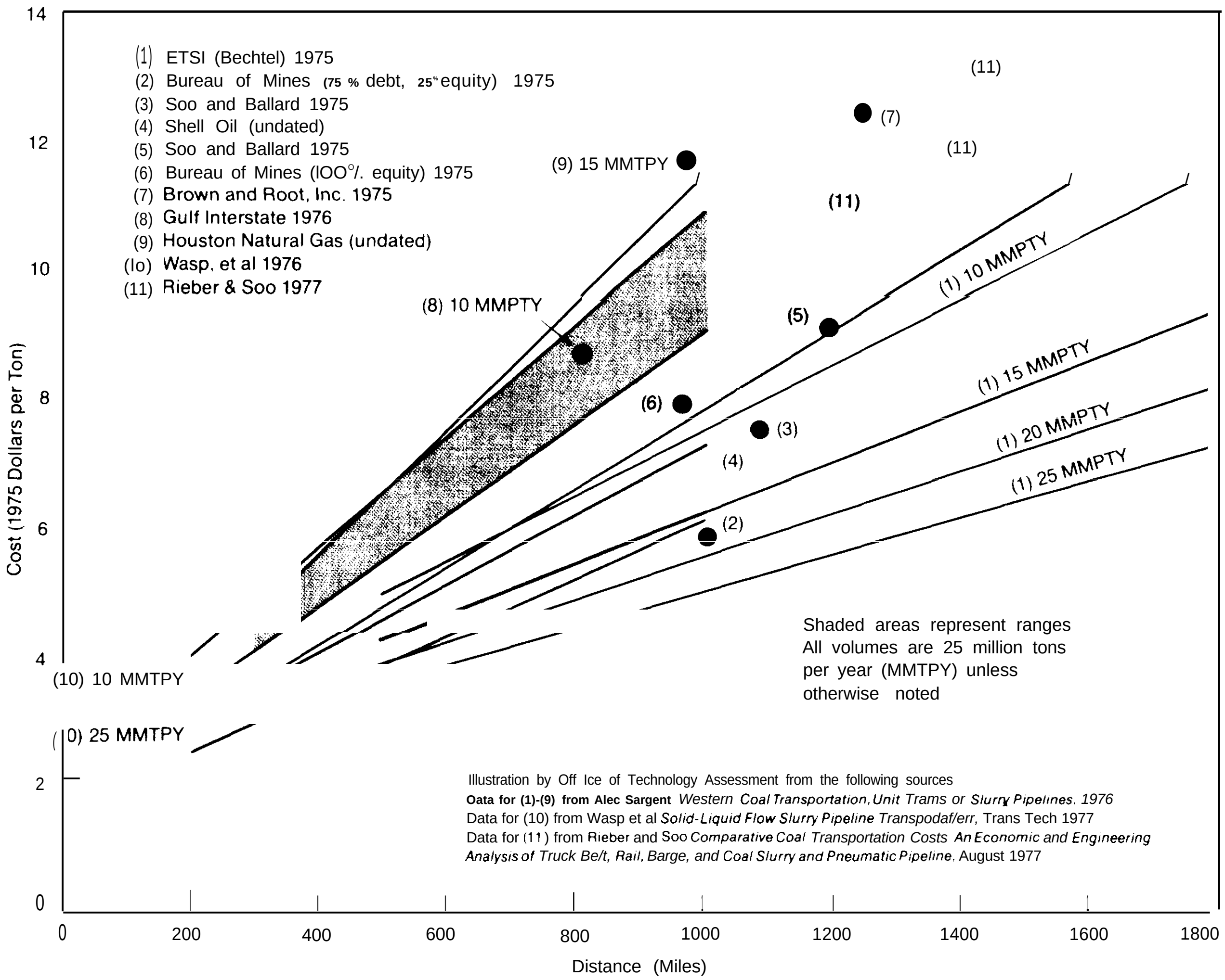


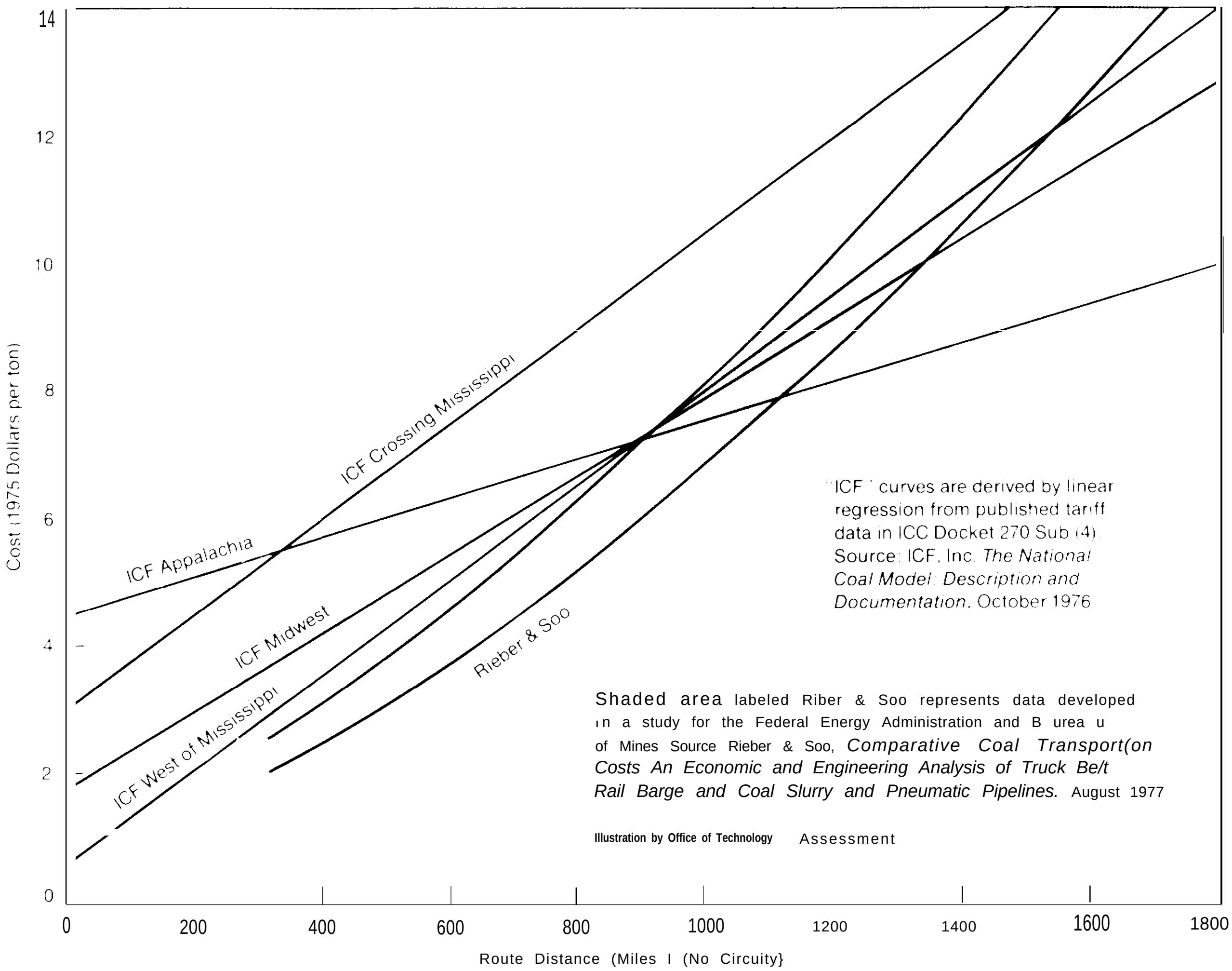
Illustration by Office of Technology Assessment from the following sources
Data for (1)-(9) from Alec Sargent *Western Coal Transportation, Unit Trains or Slurry Pipelines, 1976*
Data for (10) from Wasp et al *Solid-Liquid Flow Slurry Pipeline Transportation*, Trans Tech 1977
Data for (11) from Rieber and Soo *Comparative Coal Transportation Costs An Economic and Engineering Analysis of Truck Belt, Rail, Barge, and Coal Slurry and Pneumatic Pipeline*, August 1977

and attempting to deduce, by some general criteria, which of the coal flows identified earlier in table 7 might be carried by pipeline. To accomplish this purpose, with as little violence to the conclusions of the cost analysis as possible, assumed distances and coal volumes were varied artificially and calculations repeated to determine those combinations of values for which rail and pipeline costs are equal under the conditions governing each of the four cases. For simplicity, the computation included only a single destination region for each movement, and the resulting "indifference curves" appear in figure 19.

For each set of conditions, traffic volumes and distances above and to the right of the curve would be carried more economically by pipeline, while rail would be more advantageous otherwise. The conditions most advantageous to rail are therefore represented by the characteristics of the Montana to Becker, Minn., corridor, while those features most favorable to pipelines exist between Tennessee and Tampa, Fla., provided that one does not consider volume and distance.

The flows of coal from producing regions to consuming States in the transportation demand scenario could be compared to the indifference curves and assigned to pipelines whenever the combinations of distance and

Figure 17– Results of Previous Coal Unit Train Cost Studies



sustained volume fell in the region favorable to pipelines under all four sets 'of case condition, and barge transportation was not an obvious competitor. Only Central Western coal destined for Indiana and Texas falls in this category. Five other flows fall in a region of uncertainty between the two extreme indifference curves: Central Western to Missouri, Kansas, and Illinois; Interior Eastern to Georgia; and Southern Appalachian to Florida. Of these, the Florida traffic was assigned to pipeline because of the results of examining that specific case, Missouri and Kansas traffic was assigned to pipeline because of similarity to the Texas case and the possibility of sharing a common pipeline, Illinois was assumed to be served by rail because of the similarity of conditions to the Montana to Minnesota and Wisconsin case, and finally, the Georgia coal was considered unlikely to justify pipeline construction because of the terrain along the route,

A highly speculative but plausible traffic scenario derived in this necessarily somewhat arbitrary manner is illustrated in table 9. All other coal is assumed to travel by another mode, probably rail or barge, These *postulated* volumes are in no way intended as a projection of pipeline market penetration. They only provide a starting point for an analysis of what might happen if the equivalent of approx-

Figure 18– Results of Case Studies Comparing Coal Slurry Pipeline and Unit Train Costs

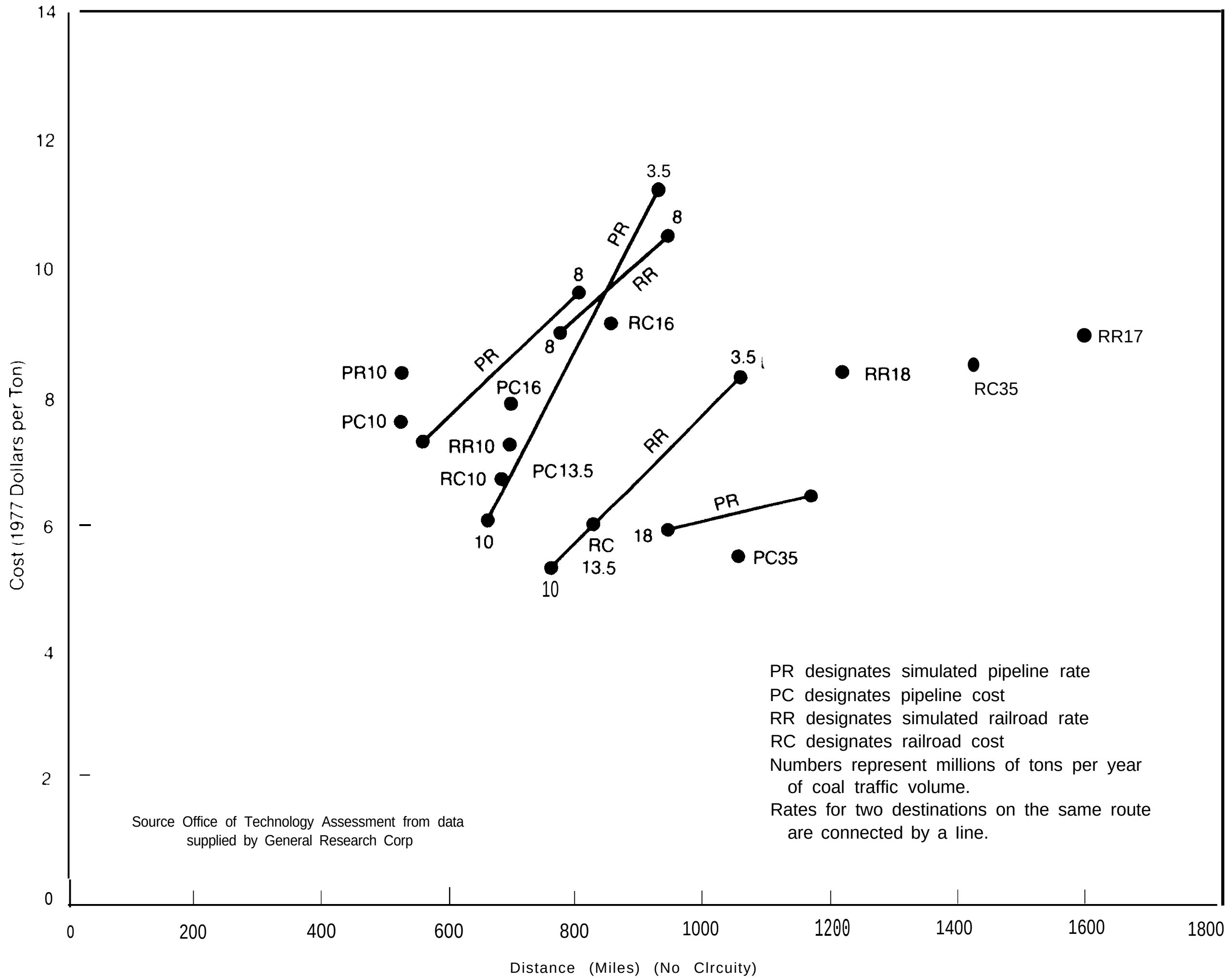
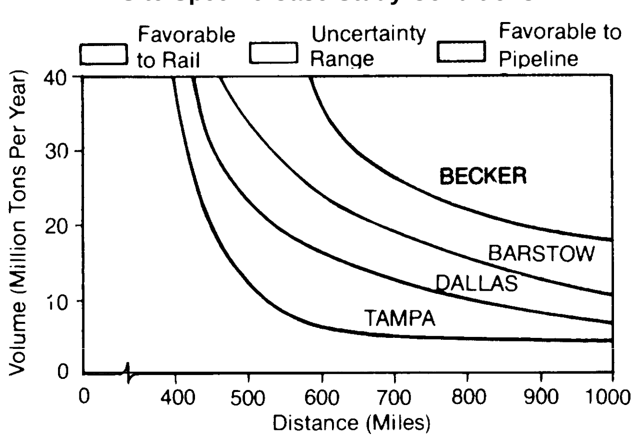


Figure 19– Rail Versus Pipeline Cost Indifference Curves Based Upon Site-Specific Case Study Conditions



Source General Research Corp

Table 9. Pipeline Traffic Scenario

(Millions of tons per year)

Origin / Destination	1985	1990	1995	2000
Central Western				
Indiana	**17**	**17**	**17**	**17**
Kansas	**—**	**—**	**19**	**19**
Missouri	**14**	**14**	**14**	**14**
Texas	**35**	**72**	**93**	**125**
Southern Appalachian				
Florida	16	16	16	32
Total	82	**119**	**159**	**207**

Note: This scenario has been developed for Illustrative purposes and does not represent a prediction that the coal volumes will be transported by pipeline or any other mode between the listed origins and destinations.

imately eight pipelines averaging 25 million tons per year were to be built between now and the year 2000.

Deriving hypothetical transportation costs for all of the listed coal flows required extending the results of the case studies, also on the basis of general and not perfectly applicable relationships. The assumed pipeline costs as derived by regression from case estimates are $272 per ton plus $0.028 per ton-mile for surface-mined coal at the approximate distances and volumes contemplated Corresponding rail costs, also generalized from the cases, are $0.82 per ton plus $0.064 per ton-mile, including a route distance circuity factor of 1.3, operating expenses, and investment in rolling stock and way and structures The methods for extending costs for both modes are elaborated in Volume I I.

A number of important simplifying assumptions underlie the scenario and should be reviewed at this point to place it in perspective. Some weigh in favor of greater apparent pipeline markets and some against.

Assumptions favorable to pipelines —

1. The demand scenario calls for a high rate of growth in power consumption after 1985
2. The demand scenario ‘predicts that all coal of a given category will be purchased by all powerplants in a State from a single source. The result is a pattern of coal flows from artificially concentrated origins
3. The cost analysis assumes that mining and power generation activity is concentrated in circumscribed locations.
4. pipelines are assumed to operate in a stable environment at full capacity. No cutover or startup costs beyond 3-year construction financing has been considered.
5. No possible additional coal tonnage required by powerplants receiving slurry coal due to water content has been accounted for.
6. No substantial increase in the present rate of railroad labor productivity improvement has been allowed for.

Assumptions favorable to railroads –

1. The demand scenario calls for a relatively high proportion of nuclear powerplant construction after 1985.
2. The possibility of serving more than one State with a single pipeline has not been considered in the market scenario, except in the case of Kansas and Missouri, and it is not reflected in the demand projections.
3. The possibility of serving industrial customers or coal conversion facilities by slurry pipelines has been ignored.
4. The possibility of distributing dewatered coal slurry by barge is not contemplated in the cost or market analyses.
5. The cost estimates give no credit for the fact that cleaning and grinding coal is more economical in conjunction with slurry pipeline operation.
6. No significant future improvement in pipeline technology has been allowed for.

Additional uncertainties of undeterminable influence involve principally railroad way and structures, investment requirements, future pipeline construction costs, and the appropriate prices to assign to water