SUSITNA
HYDROELECTRIC PROJECT

FEDERAL ENERGY REGULATORY COMMISSION
PROJECT No. 7114

ANALYSIS OF THE COAL ALTERNATIVE FOR SUPPLYING POWER TO THE RAILBELT REGION OF ALASKA

DRAFT REPORT

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SUSITNA JOINT VENTURE

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Prepared for
Alaska Power Authority

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EXECUTIVE SUMMARY

Coal-fired electricity generation is one method for providing electric power to the Railbelt region of Alaska. The utility of this alternative is largely related to the present and projected availability and cost of coal in Alaska. Alaska is a vast storehouse of coal with major, developable, fields being Nenana and Beluga. Coal can, therefore, be made available to generate the electricity demanded. This analysis of the coal alternative for electricity power generation in the Railbelt Region examines four issues: 1) present and projected demand for coals mined in Alaska; 2) current and projected supply of Alaska coals; 3) appropriate concepts for projecting coal prices; and 4) current and projected prices of Alaska coals.

Demand and Supply of Alaskan Coal

At present, there is a modest domestic demand for Alaska coal and some potential for growth in that market. Similarly, there is only one supplier, the Usibelli mine located in the Nenana coal field. The Usibelli mine, located in the general vicinity of Fairbanks, supplies 830,000 tons annually for domestic consumption. Usibelli also has a 15-year export contract with Suneel. This contract provides for the export of 880,000 short tons annually to the Korean Electric Power Company. Table 1 shows how Nenana coal demand could increase in relation to the existing Suneel contract and the thermal alternative expansion plan. Demand for Nenana coal could quadruple from 1984 to 2000 if the Susitna hydroelectric facility is not built.

The reserves of the Nenana field are more than adequate to support both more exports and the level of production associated with additional coal-fired plants. The reserve base of the Nenana coal field is measured in hundreds of millions, if not billions, of tons. Similarly, production could be expanded to accommodate the growth potential. However, Usibelli's existing production capacity is utilized at about 80-90 percent by the 1.7 million tons annual production level at the existing Poker Flats mine. Expansion of production beyond 2.0 million tons annually would entail a distinctly separate mining effort.

In addition to the two 200 MW thermal plants projected for the interior region shown in Table 1; thermal power plant expansion also could include three

200 MW plants built in the southern Railbelt based upon the Beluga coal field. Such plants could be built at the mine mouth. The thermal alternatives analysis shows gas, not coal, as the primary thermal fuel for expansion of Anchorage area generation capacity throughout this century. The domestic market for Beluga coal is largely a long term, rather than near term opportunity.

The anticipated major market or source of demand for Beluga coal is the export market. The potential Pacific Rim market for Alaska coal exports is impressive. Table 2 shows the forecast of Pacific Rim nation coal imports through 2040 in metric tons coal equivalent or MTCE. (The MTCE is based on the energy content of a coal that contains 27 million Btu per ton. Beluga coal has about 15 million Btu per ton; hence, each MTCE equals 1.8 tons of Beluga coal.)

Beluga reserves are vast and Beluga production costs are relatively low on the world market. If no internal Alaska constraints limits Beluga coal mine development. Beluga producers could capture 11 percent of the Pacific Rim market by the year 2000, and about 19 percent for the growing market by 2030. Current production cost calculations demonstrate that this coal will be cost competitive in the Pacific Rim market. Table 3 shows an estimate of the high potential for exports of Alaska coal if no internal constraints limit the number of mines opened, or limit the environmental acceptability of mining growth. These estimates represent unconstrained potential demand for Alaska coal based on what the market could absorb.

Currently no active mines exist in the Beluga coal field. Diamond Alaska is aggressively planning for the development of a 10-12 million ton per year mine by the early 1990s. The scale and pace of Beluga development required to meet the potential demand would be exceptional even when compared with the rapid growth experiences of Prudhoe Bay, Gillette, Wyoming or Grants, New Mexico. Any number of cultural, social or ecological systems could act to constrain development of Beluga coal mining to production levels well below what the Pacific market could absorb. While maximum allowable production levels cannot be predicted, a reasonable development path that considers effective management of

1. Add footnote.

potential conflicts might yield production growth as shown on Table 4. When Table 4 is compared to Table 3, it is readily apparent that export demand in the Pacific Rim will almost always exceed supply for Alaskan coal from the Beluga field.

There are three price concepts that have been used to analyze Alaska coals:

(1) The full cost of production;

(2) The price which would induce coal users to switch to an alternative fuel (e.g. natural gas); and

(3) The market price of coal adjusted to Alaska.

The first price concept, production cost, sets a lower bound below which prices cannot go. The second concept, fuel substitution, sets a long run upper bound. The third concept applies under competitive market conditions.

As has been inferred above, Nenana coal pricing must be treated separately from Beluga pricing. Economically, there is no "Alaska coal". There is Nenana coal and there is Beluga coal. These distinctions largely result from market and infrastructural considerations. The three pricing concepts have been applied, as appropriate, to both the Nenana and Beluga coals.

Coal Prices

Production costing and fuel substitution pricing apply to all coal. Pacific Rim market pricing applies to Nenana and Beluga coals under two conditions:

(1) When there is a demand for Alaska coal in the Pacific Rim market at a price above Alaska production cost;

(2) When the Pacific Rim market can absorb all of the Alaska production.

For the long run period of the Susitna Project, the Pacific Rim market price FOB Beluga is the appropriate resource valuation concept for Beluga coal. This analysis demonstrates that Beluga coal will have a lower cost delivered to tidewater than Nenana coal when the former comes into production in the 1990s. Hence, Beluga coal from large mines will be better able to compete in the

Pacific Rim market than Nenana coal. As a result, the major market for Nenana coal will be the Fairbanks area. Thus, the Pacific Rim market price FOB Nenana is not the appropriate resource valuation concept for Nenana.

Coal prices in the localized Fairbanks market will be set by bilateral negotiation. No deterministic economic model can project the price trend for Nenana coal. A production cost basis for valuing Nenana coal resources is projected as a conservative resource valuation approach that understates the long-term market price of coal in Nenana.

Nenana Coal Prices. The range of contract prices for coal sold by Usibelli into the Fairbanks market demonstrates the analytically indeterminate nature of commodity prices in a small market. Prices are set by bilateral negotiations. In the Nenana coal case a monopolist seller is dealing with a few buyers. The resulting prices, therefore, cannot be analytically predicted except for the minimum and maximum prices.

A production cost analysis was chosen as the most useful and conservative method to project the applicable price for future Nenana deliveries resource valuation approach. Table 5 provides the mining and transportation cost for Usibelli mined coal delivered by rail to a coal plant at Nenana.

Beluga Coal Prices. The Pacific Rim will become a large and rapidly growing coal market. Diamond Alaska alone anticipates producing 10 to 12 million tons annually for export before the end of this century, and other firms also have interest in this market. The Beluga coal producers will be able to sell all of their coal that can reasonably be supplied into the Pacific Rim over the long term. The export market will be sufficiently robust that it will be capable of absorbing 3 to 4 times the amount of coal that the Beluga field will be capable of producing. Thus, over the long run the Pacific Rim market price FOB Alaska is the economic basis for valuing Beluga coal.

Over the long run, the 65 year period of the Susitna project evaluation, market conditions for coal in the Pacific Rim can be expected to change from time to time, reflecting short-term imbalances--relative surplus or shortage conditions in the market. Temporary periods of recession may reduce demand for coal, causing lower prices. Temporary periods of fuel tightness, such as could be caused by oil embargoes or gas supply constrictions, could raise the demand for coal and cause higher prices. There is no basis to predict when minimum or maximum prices might occur for a commodity such as coal. Thus, over the long run, the Pacific Rim market price trend FOB Alaska remains the only economic basis for valuing Beluga coal.

The Pacific Rim market coal price trend over the long run is based on a competitive market analytic model. The economic conditions of the competitive market model yield the lowest prices that will match supplies to demand. Higher trend prices could be projected by assuming higher resource rents or higher taxes, such costs may occur as world energy resources become more scarce, relative to demand, in the long run. These "extra" market factors are not estimated. Adopting a Pacific Rim competitive market basis for valuing the Alaska coal resource at Beluga accomplishes two results:

(1) The Alaska resource at Beluga is valued at the highest and best use that can reasonably be anticipated;

(2) The estimated coal price trend has a somewhat conservative bias, because external economic conditions in the Pacific Rim (e.g. increased taxes) over the long term could expect an upward force on market clearing prices.

The Pacific Rim market price for FOB Beluga mine is shown on Table 6. It is compared with estimated production costs in Table 6, also, to show the competitiveness of Beluga coal in the export market. Beluga coal can be produced at a lower cost--quality adjusted--than other competing coals in the Pacific Rim market. It will move strongly into this market before the end of this century.

TABLE 1

NENANA COAL DEMAND

Annual Coal Consumption (thousand tons per year)	Demand Basis
830	Existing Domestic Demand
1710	Existing Domestic Demand plus Suneel contract at full capacity
2610	First 200 MW coal plant added to above demand
3500	Second 200 MW coal plant added to above demand

TABLE 2

PACIFIC RIM COAL IMPORTS: 1990-2040
(Million MTCE)1/

Year	Steam Coal for Electric Power	Total Coal
1990	83	104
2000	108	167
2010	176	288
2020	256	410
2030	349	550
2040	395	662

1/ One metric ton coal equivalent (MTCE) contains 27 million Btu.

TABLE 3

POTENTIAL UNCONSTRAINED ALASKA COAL EXPORTS

Year	Million Tons Coal Exported Per Year
2000	31
2010	78
2020	131
2030	179
2040	222

TABLE 4

CONSTRAINED BELUGA COAL DEVELOPMENT

Year	Million Tons Coal Exported Per Year
2000	10-15
2010	25-30
2030	50-60
2050	75-100

TABLE 5

NENANA COAL PRICES
(1985$/Million Btu)

Year	Cost Component: Mine Mouth Coal Production	Cost Component: Rail Transportation to Nenana	Total
1985	1.45	0.39	1.84
1990	1.56	0.43	1.99
1995	1.67	0.47	2.14
2000	1.80	0.51	2.31
2010	2.08	0.61	2.69
2020	2.40	0.73	3.13
2030	2.77	0.87	3.64
2040	3.20	1.04	4.24
2050	3.70	1.24	4.94

TABLE 6

BELUGA COAL PRICES COMPARED TO PRODUCTION COSTS
($1985/Million Btu)

Year	Pacific Rim Market Price FOB Mine	Production Cost
1985		1.17
1990	--	1.26
1995	--	1.36
2000	1.78	1.46
2010	2.30	1.69
2020	2.57	1.96
2030	3.08	2.27
2040	3.22	2.63
2050	3.37	3.04

1.0 INTRODUCTION

1.1 THE COAL ALTERNATIVE FOR RAILBELT POWER GENERATION

Coal has been a primary source of energy in the U.S. economy since the beginning of the industrial revolution. It has been a traditional fuel for electricity generation, particularly in baseload power plants. Coal is used in Rankine or steam cycle power generation. High pressure elevated temperature steam is raised in a boiler and expanded across a turbine. This expansion of steam turns the turbine, connected to a generator, producing electricity.

Coal is the dominant source of energy for electric utilities throughout the United States, shown in Figure 1-1. Figure 1-1 further illustrates that coal will become increasingly important as a power plant fuel. The growth in coal utilization by utilities has proceeded at a steady rate, shown in Figure 1-2. It has grown despite the environmental restrictions governing coal burning, and the relatively high capital cost associated with field erection of solid fuel burning equipment. The development of coal technology as a method for generating electricity in the U.S. provides an alternative energy source for baseload power in the Railbelt Region of the 49th State. This alternative must be analyzed because of the vast deposits of subbituminous coal in Alaska. The best coal deposits are in the Railbelt Region. These are shown in Figure 1-3. Coal is now mined in the Nenana Field and in the near future may be mined in the Beluga field, as several companies are now planning new mines there. This analysis of the coal alternative for power generation in the Railbelt Region of Alaska includes examination of the following issues: 1) present and projected demand for coals mined in Alaska; 2) current and projected supply of Alaska coals; 3) appropriate concepts for projecting prices of Alaska coals; and 4) current and projected prices of Alaska coals.

Alaska is viewed as a supplier of several coals, rather than a homogeneous commodity, "coal". All coals vary to greater or lesser extents as a function of seam quality, deposit structure (e.g., coal depth and thickness, condition of overburden and inner burden), infrastructure availability, proximity to load centers, and so forth. Alaska coals are not different from lower 48 U.S. coals in this respect. Because Alaska offers several coals, this analysis begins in

Section 1.2 with overview data but then focuses on an analysis that is oriented to specific coal fields of the Railbelt.

The Alaska Power Authority and its consultants compiled a detailed assessment of the availability and price of various indigenous coals in Alaska. Such an analysis is presented in subsequent sections. Section 2.0 provides the theoretical basis for Alaska coal prices and price projections. Section 3.0 examines the demand for Alaska coals. Sections 4.0 and 5.0 estimate coal supplies and prices for Nenana and Beluga coals.

1.2 OVERVIEW OF ALASKA COAL RESOURCES

Alaska has deposits of coal both outside and inside the Railbelt region. Alaska deposits, in total, contain approximately 130 billion tons of resources (Averitt 1973). Alaska has billions of tons of reserves. The Nenana and Beluga deposits are the most economically promising Alaska coal for major supply activities as they are very large and have favorable mining conditions. The Beluga fields in this discussion include the Yentana and Beluga deposits in the Susitna coal field. The Matanuska coal field is the third property of immediate concern, and it is discussed in this chapter.

Davis, in Energy Alaska, identifies three basic coal bearing regions within Alaska: the Arctic, the Interior, and the Southcentral. Some coal resources may exist in the Southcentral region. The total coal resource base for Alaska is some 2.0 - 5.7 trillion tons, as shown in Table 1-1.

The largest single coal bearing region may be the Arctic region. Arctic Alaska coal resources are shown in Table 1-2. Much of this is high quality bituminous coal, however, infrastructural and climatological constraints prevent its development for the Railbelt region.

The Interior region contains the Nenana field as is shown in Table 1-3. While this region contains fewer total resources than the other major regions, it has almost 900 million tons of measured resources, largely the reserves under lease either to Usibelli Coal Mine or to other coal companies (e.g. AMAX Coal).

The coal resources of the Southcentral region are shown in Table 1-4. It is useful to note that the measured resources of coal in the Yentna-Beluga field approach the size of those in the Nenana field. Other areas of interest have much smaller measured, indicated, or inferred resources; deposits that can be used reasonably safe for planning purposes. Of particular interest is the fact that there are no measured coal resources shown in the Kenar area, and only 6.6 million tons of measured resources in the Matanuska coal field. However, the Matanuska deposits occupy a potentially favorable market niche as discussed below.

1.2.1 Matanuska Coal

The Matanuska coal field, located within the Railbelt region, is of some interest for this study. The Matanuska coal field may be divided into two districts: the Wishbone Hill, which contains high volatile bituminous coal, and the Anthracite Ridge District, which includes coal of anthracite rank. At one time, several underground and surface mines operated in the Wishbone Hill District. Underground mining ceased in the early 1960s and surface mining ceased in 1968 with the closing of the Evan Jones Mine (Schaff & Merritt, 1983).

Seams in the Wishbone Hill District occur in a large, steeply dipping, faulting syncline. The Wishbone Hill seams are generally variable in thickness and quality. It is estimated that 6,000,000 tons have been mined from this district, constituting the most readily exploitable reserves. The remaining resources are in small blocks or are deeply buried. There are, however, some 40 million tons of surface minable reserves still available in the Wishbone Hill District. These reserves would be sufficient to maintain a 0.5 to 1.0 million ton per year operation. These surface minable deposits have been the target of a privately financed exploration program during the winter of 1984-1985 (Merritt, Alaska DGGS personal communication to M. Feldman, April, 1984). Seams in the Anthracite Ridge District are generally thin and discontinuous, though seam thicknesses as much as 10 to 14 feet have been reported. The tight folding and faulting, combined with the discontinuous nature of the seams, restricts development of these reserves. The resource estimations in this coal field are variable; it is likely that the identified resources are just over 100 million tons (Sanders 1981). The fact that seams are generally thin, discontinuous, and tectonically disturbed reduces the possibility of upgrading the resource to reserve status. Nevertheless, the bituminous seams in the area of the Evan Jones Mine, when washed, have low sulfur values (0.4 to 0.5 percent) and high calorific values (12,000+ Btu, dry basis). It is conceivable that a compliance-grade, steam market product could be produced with the use of innovative mining methods and coal preparation (Patsch 1981). Given these data, it is apparent that the Matanuska field is capable of supporting the MPP, but is not capable of sustaining a large scale Alaska coal industry, or a large coal-fired power generation effort.

Recently, the state leased 5,200 acres of Matanuska field coal land to Rocky Mountain Energy/Rock Spring Royalty Company. Terms of the lease on three tracts of land in the Wishbone Hill and Moose Creek areas included a cash bonus of $2.53/acre, a rental fee of $3/acre, and a royalty fee of 5% of the adjusted gross income. Placer Amex also maintains a lease in this field (Alaska From the Inside 12-19-85).

Detailed studies have been made concerning the cost of Matanuska coal. These studies have resulted in a coal price of $1.79/Million BTU in 1985 dollars. This price is significantly higher than the costs of Nenana or Beluga coal as shown in the Executive Summary.

1.2.2 Nenana and Beluga Coal

Because of the various constraints described above, surface minable deposits in the Nenana and Beluga fields are most appropriate for supporting a large build-up in coal production or a large scale effort to generate electricity by steam-electric power plants. This view is the consensus not only of Harza-Ebasco and Dames & Moore, but also prior analysts of power generation in Alaska such as Battelle Northwest Laboratories.

The Nenana field contains some 3.6 billion tons of measured and indicated coal resources and 3.4 billion tons of inferred coal as shown in Table 1-3. The total potential resource base is over 17 billion tons. This field is now supporting the production of 830,000 tons/yr for domestic use.

The Beluga coal field contains some 10.2 billion tons of identified and undiscovered resources. Hypothetical resources are listed at 27 billion tons.

(See Table 1-4.) While there is no production from the Beluga field currently, plans for a mine have been announced by the Diamond Alaska Coal Company. The Diamond Alaska plan is for a 12 million ton/yr surface mine designed primarily to serve the export market (Alaska J. of Commerce, Vol. 8, No. 8, 2-20-84, p. 7). Because the Nenana and Beluga fields show the greatest capability for supporting large scale coal developments, they are analyzed in subsequent chapters.

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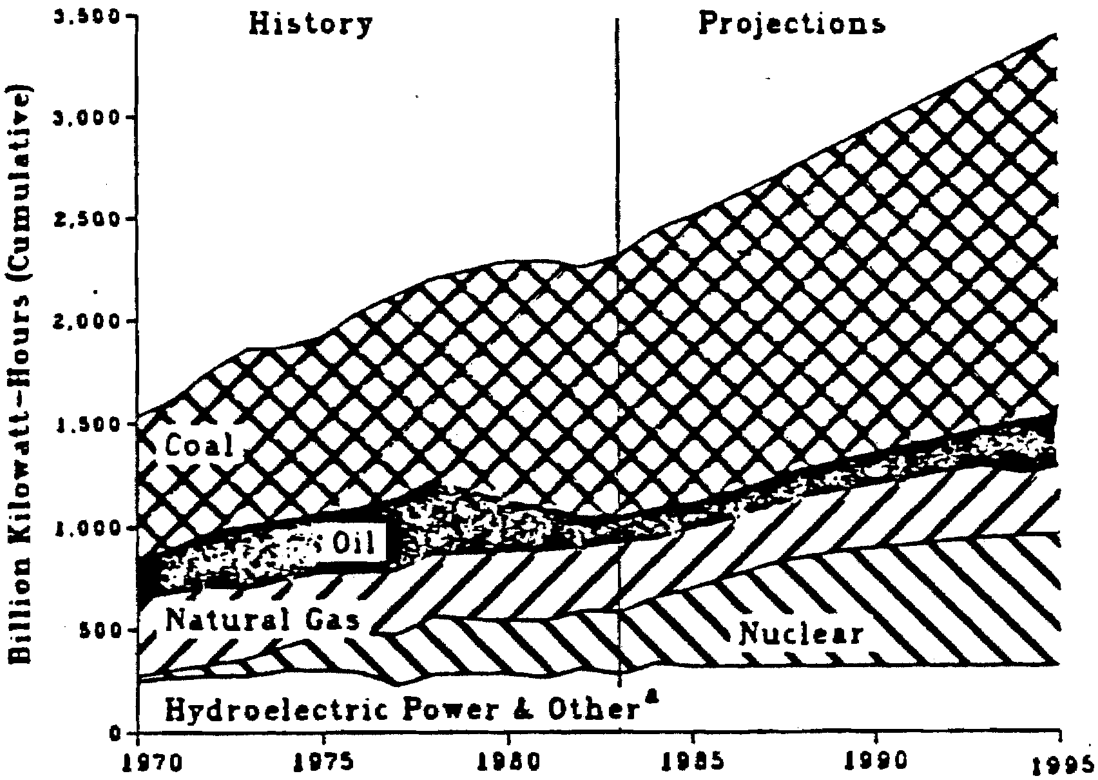
Sources of Electrical Supply,
Midprice Scenario, 1970 to 1995



[a]Other includes geothermal, wood, waste, and net imports of electricity.
Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83); Monthly Energy Review, DOE/EIA-0035(83)/12[4]) (Washington, D.C., 1984).

FIGURE 1-1 Source: USEIA 1984b

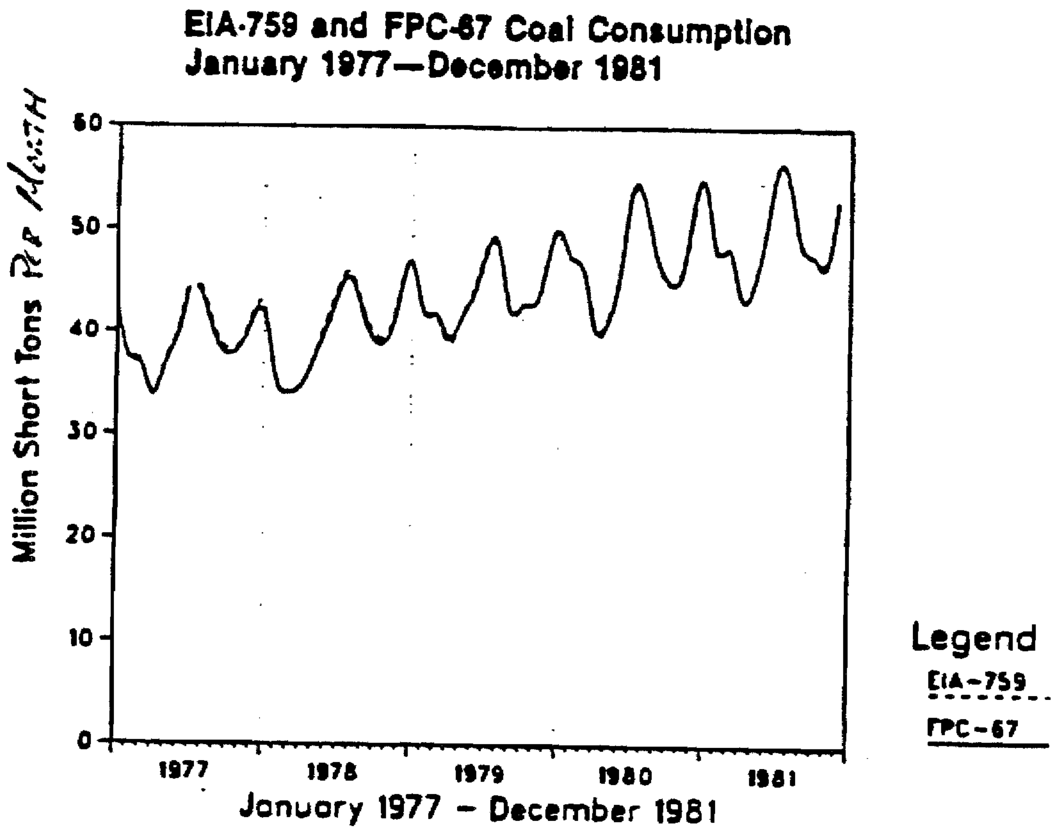


FIGURE 1-2 Source: USEIA 1984a

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Railbelt Coal Reserves

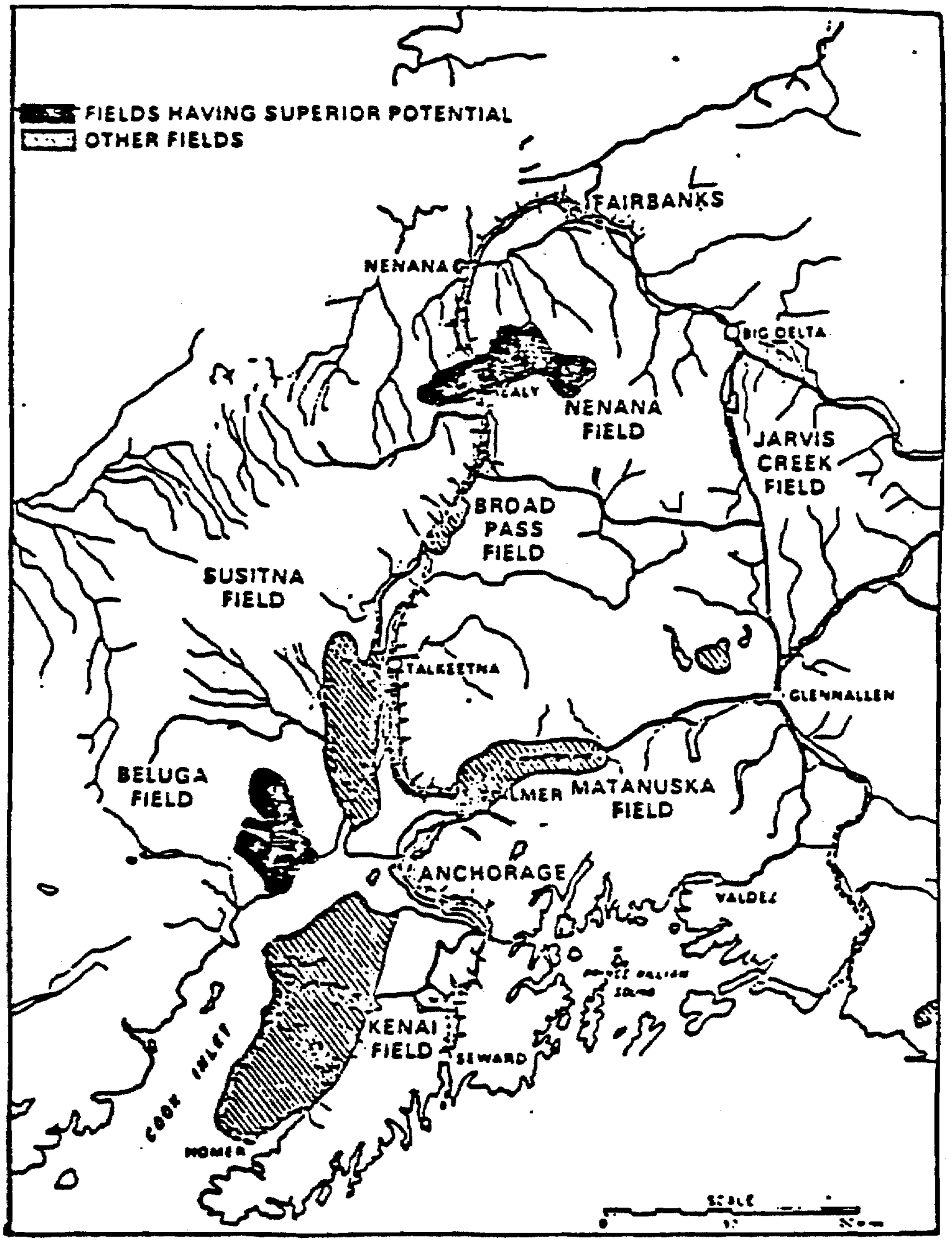

FIGURE 1-3

TABLE 1-1

SUMMARY OF ALASKA'S COAL RESOURCES

Region	Measured a	Indicated b	Total c = a + b	Inferred d	Total Identified e = c + d	Hypothetical & Speculative f	Total Resources e + f
	Coal Resources (estimates in millions of tons)						
	Identified Resources					Undiscovered Resources	
	Demonstrated						
Arctic	35	2,760	2,800	118,000-119,000	60,000-146,000 1/	402,000-4,000,000	462,000-4,150,000
Northwest	---	---	---	---	---	---	---
Interior	862	2,700	3,560	3,380	6,940	10,400	17,300
Southwest	---	---	---	---	---	3,290	3,290
Southcentral	757	2,070	2,820	7,850	10,700	1,480,000	1,490,000
Southeast	---	---	---	---	---	---	---
Totals	1,650	7,530	9,180	129,000-130,000	77,600-164,000	1,900,000-5,500,000	1,980,000-5,660,000

1/ This entry reflects the range in estimates given by Sanders (1982) rather than the actual sum of Demonstrated and Inferred resources (column c plus column d).

SOURCE: Davis 1984.

TABLE 1-2

ARCTIC REGION COAL RESOURCES OF ALASKA

Locality	Coal Resources (estimates in millions of tons)					
	Identified			Undiscovered		
	Demonstrated					
	Measured	Indicated	Inferred	Hypothetical	Speculative	Total Resources
Corwin Bluff district	---	56.0	926	---	---	982
Cape Beaufort district	35.0	312	686-936	---	---	1,030-1,280
Chukchi Sea area	---	---	---	3,000[1]	50,000-1,000,000	53,000-1,000,000
Kukpowruk River district	---	247	2,820	---	---	3,060
Kokolik River district	---	99.0	2,240	---	---	2,340
Utukok River district	---	262 (bit.[2] 91.0)	47,200 (bit. 2,650)	---	---	47,500
Kuk-Kugra Rivers district	---	107	2,140	---	---	2,250
Meade River district	---	894 (bit. 103)	41,800 (bit. 846)	---	---	42,700
Ikpikpuk River district	---	97.0	2,530	---	---	2,620
Colville River district	---	685 (bit. 242)	18,000 (bit. 6,980)	---	---	18,700
East of Itkillik River	---	---	---	---	50,000	50,000
Unspecified by area	---	---	---	120,000 2,300,000	--- ---	120,000-2,300,000
Totals (1976 estimates)	35.0	2,760	118,000-119,000	123,000-2,300,000	100,000 1,050,000	344,000-3,470,000
Most Recent Estimates	60,000-146,000			402,000 4,000,000		462,000 4,150,000

1/ Within 3 nautical miles from shore
2/ Bituminous coals

SOURCE: Davis 1984.

TABLE 1-3

INTERIOR REGION COAL RESOURCES OF ALASKA

Locality	Coal Resources (estimates in millions of tons)					
	Identified			Undiscovered		
	Demonstrated					
	Measured	Indicated	Inferred	Hypothetical	Speculative	Total Resources
Eagle-Circle area	---	---	---	100	---	100
Nation River occurrence	---	---	---	50	---	50
Yukon River-Rampart district	---	---	---	50	---	50
Nenana Coal fields	862	2,700	3,380	8,680	1,500	17,100
(Jarvis Creek field)		(6)	(8-71)	(18)		(32-95)
(Farewell-Little Tonzona area)					(1,500)	(1,500)
Total	862	27,70	3,380	8,900	1,500	17,300

SOURCE: Davis 1984.

TABLE 1-4

SOUTHCENTRAL REGION COAL RESOURCES OF ALASKA

Locality	Coal Resources (estimates in millions of tons)					
	Identified			Undiscovered		
	Demonstrated					
	Measured	Indicated	Inferred	Hypothetical	Speculative	Total Resources
Yentna-Beluga (Susitna) field	750	1,650	7,800	26,900	---	37,100
Kenai-Homer district	---	318	---	24,000	---	24,300
Offshore Cook Inlet	---	---	---	130,000	1,300,000	1,430,000
Matanuska coal field	6.6	40	52	149	---	248
Broad Pass field	---	64	---	110	---	174
Bering River field	0.015	---	---	3,000	---	3,000
Totals (rounded)						
Totals (rounded)	757	2,070	7,850	184,200	1,300,000	1,494,800

SOURCE: Davis 1964.

2.0 PRICING OF ALASKA COAL

2.1 ECONOMIC CONCEPTS OF PRICE-SETTING MODELS FOR ALASKA COAL

As a prelude to the analysis of coal from each major Alaska Field, it is useful to review the appropriate price setting mechanisms. Coal is a commodity. Commodity prices are determined by market forces, not necessarily just the costs of production. Coal prices may or may not reflect the cost of production at any given location. Certainly, the world price of oil bears little relationship to the cost of producing oil in Saudi Arabia, or even East Texas.

There are three price-setting mechanisms which, at different times during the 50-year life of the project, may set or influence fuel prices faced by coal-fired utilities in the Railbelt:

1. Cost of production

2. Cost of alternative fuels in the Alaska market

3. The market price of Pacific Rim coal delivered to major economic centers (e.g., Japan), minus transport costs back to Alaska

The third mechanism is called the Pacific Rim price FOB Alaska. Each of the mechanisms results in a different theoretical price for coal supplied to Railbelt utilities. In the real world of negotiated prices between Alaska utilities and Alaska coal producers, actual prices will be negotiated with reference to these price-setting mechanisms. Through time each of them may have greater or lesser influence on the price for Alaska coal for different periods.

Coal for electric utility use is usually purchased under long-term contract. These contracts typically lock-in a base price but allow the coal producer to escalate coal price according to some agreed upon index of price escalation. The contract base price depends on the structure of the market (the number of buyers and sellers) as well as conditions in the market at the time the contract is made. Price may vary from a minimum cost of production to a maximum cost of the next lowest cost fuel source. Contracted prices also may contain price re-openers to protect both buyers and sellers from exogenous re-evaluation of coal such as occurred in 1973 when world energy prices were disrupted.

A coal producer may be able to exercise market power and sell coal above his production cost as long as his price remains below the cost of the next least costly coal supply or the cost of electrical generation using the next least costly alternative fuel, natural gas, in Alaska.

As long as gas remains the least costly Alaska alternative fuel in the Anchorage area, gas will remain the principal fuel used for power generation in the Railbelt area. The relative status of coal and gas prices will reverse by the turn of the century. Coal will become the least costly fuel for thermal power plants and gas will be the alternative fuel. The price of the least costly alternative (gas) will impose an upper limit on domestic coal prices in the Anchorage area. Coal producers (e.g., in the Beluga field) can never charge a price for their coal that would allow utilities to generate power more cheaply using gas. The coal price which induces utilities to add gas-fired rather than coal-fired capacity is called the gas-equivalent value of coal. The gas equivalent value takes into account the higher cost of building coal-fired power plants and burning coal.

It should be noted that this fuel substitution price is a long-run concept. Fuel substitution prices can be exceeded in the short run when fuel users have insufficient time to make the necessary technical adjustments to accommodate fuel switching (in economic terms, long-run cross-price elasticities are always greater than short-run cross-price elasticities). Also, it should be noted that the fuel substitution prices are not strictly Btu equivalents. Gas valued at $5/MCF (or $5/MMBtu) will not yield a coal price of $76/ton for 15.2 million Btu/ton coal. Rather, there will be some site-specific and project-specific technical adjustment to accommodate the higher capital and operating costs associated with coal-fired units. These prices are, however, the long-run upper limit for coal prices.

The final pricing concept of importance is market pricing, particularly with respect to the Pacific Rim coal market. The Pacific Rim coal market is rapidly growing. Further, the Pacific Rim coal market has numerous sellers of coal (e.g., various mines in Australia, Western Canada, South Africa, etc.) and numerous purchasers of coal in Japan, Korea, Taiwan, and elsewhere.

Alaska coal prices may be set with reference to Pacific Rim coal values if Alaska coal is successful in moving into this market. This Pacific Rim price FOB Alaska could be higher or lower than production costs. The latter would imply Alaska coal cannot compete in the export market. Thus, the export market would have no influence on the local Alaska market or coal prices. If, however, the export price were higher than Alaska production costs, local Alaska selling prices to move up to export prices, assuming all available supplies could be sold in the Pacific Rim market.

Pacific Rim coal market prices, over the long run, will be influenced by the cost of substitute fuels--natural gas or fuel oils which influence the demand for coal--but will be set with reference to the coal supply and demand conditions in the Pacific Rim. There will be sufficient buyers and sellers of coal and of alternative fuels in the Pacific Rim to constitute a reasonably competitive market. This implies that the cost of the last increment of supply to satisfy demand will set the price in the Pacific Rim.

For Alaska coal prices to be set at to the cost of producing the last increment of Alaska coal supply, two conditions must apply: 1) export opportunities must be ruled out; and 2) competitive forces must exist within the local Alaska market.

Competitive market conditions, characterized by many buyers and sellers and a homogeneous product, are required to force prices toward the cost of the marginal producer. A competitive market price is not the same as the lowest production cost. The last increment of supply to meet demand sets the competitive market price. This price may afford some lower cost sellers a higher return on their investment than the marginal supplier receives. Lower cost producers have no incentive to set lower prices. They can capture the market price; if they price their coal at less than market they are foregoing the opportunity for higher returns to invested capital.

Presently, the Alaska coal market has none of the features of a competitive market. It is now a small, localized Fairbanks market with only one seller. Even if Beluga and Matanuska coal are sold locally, there will be few sellers. Similarly, there are and will be only few Alaska buyers, the few utilities with coal-fired capacity or plans to build such capacity in the Railbelt. The differences in mine location are important factors. Because no railroad serves Beluga, its coal cannot move throughout Alaska. Railroad freight rates are high for Nenana coal; hence, it cannot (by our estimates) move into the Beluga local area market. Thus, Nenana and Beluga coals will not directly compete in a single Alaska market.

In a small market there is no deterministic model for predicting price. The seller will have the opportunity to exercise market power and negotiate a price higher than his cost of production; or a simply refuse to sell locally at a price below his best alternative--the Pacific Rim price FOB Alaska.

2.2 PRICE CONCEPT SELECTION

Three pricing concepts have been identified: 1) fuel substitution; 2) Pacific Rim market price FOB Alaska; and 3) production costing. Fuel substitution sets a long-term upper bound on the prices. Production costing sets a lower bound. The Pacific Rim market price FOB Tidewater, Alaska falls somewhere between the two price limits.

Coal prices in the localized Nenana field (Fairbanks) market will be set by bilateral negotiation at or above the full cost of production, given some notion of a market clearing price with respect to alternative fuels. No deterministic economic model can predict the price trend for Nenana coal. A production cost basis for valuing Nenana coal resources is projected as a conservative resource valuation approach that, doubtless, understates the long-term market price of coal in Nenana.

Beluga coal prices are largely determined by Pacific Rim markets. Pacific Rim market pricing holds under the following conditions:

1. When there is a demand for Alaska coal in the Pacific Rim market at a price above Alaska production costs; and

2. When the Pacific Rim marketplace can absorb all of the Alaska production.

This analysis shows that, for the long-run period of the Susitna project, the Pacific Rim market price FOB Beluga is the appropriate resource valuation concept for Beluga coal. This analysis also shows that when Beluga coal comes into production in the 1990s, it will be lower cost delivered to tidewater than Nenana coal. hence, Beluga coal from large mines will be better able to compete in the Pacific Rim export market than Nenana coal. As a result, the major market for Nenana coal will be the Fairbanks area. Thus, the Pacific Rim market price FOB Nenana is not the appropriate resource valuation concept for Nenana, in contrast to the situation in Beluga.

2.3 ESTIMATED PRICES FOR NENANA AND BELUGA COALS

Section 3.0 surveys demand for Alaska coal. Sections 4.0 and 5.0 contain the detailed basis for estimating prices for Nenana and Beluga coals delivered to Alaska utilities to fuel the thermal alternatives. These price estimates are the result of demand/supply analysis.

3.0 DEMAND FOR ALASKA COAL

Currently there is a modest domestic demand for Alaska coal, and some potential for growth in that market. Additionally, there is some export of Nenana coal to Korea and significant potential for expanding exports of Alaska coal. Both domestic and export markets are examined below.

3.1 DOMESTIC DEMAND FOR ALASKA COAL

The Usibelli mine located outside of Healy, in the general vicinity of Fairbanks, is the only commercially active coal mine in Alaska. It produces coal for sale to Fairbanks Municipal Utility System, Golden Valley Electric Association, the U.S. Department of Defense, the University of Alaska, and other miscellaneous users. Table 3-1 summarizes the current domestic consumption of Alaska Coal--in excess of 800,000 tons/yr. Table 3-2 summarizes electric utility coal burning capacity.

In addition to the 800,000 tons/yr of coal consumed as shown in Table 3-1, there are some immediate firm and tentative plans to increase domestic consumption of coal. Fairbanks Municipal Utility System is proceeding with plans for a small (25 MW) modern facility generating electricity to support the district heating system of Fairbanks. The Matanuska Power Project (MPP) has been proposed by a joint venture of Hawley Resources and Signal Energy Co. MPP is a 150 MW facility to be based upon consumption of about 700,000 tons/yr of Matanuska field coal (Wheelabrator, 1984, p. 4).

The MPP project exists in a uniquely favorable niche in that it can serve a large market and can be built at very favorable construction costs. It is located just outside of Palmer, well within reach of the Anchorage labor force. It is located on the Alaska railroad, facilitating delivery of major components of the power plant almost to economic life. It is located at the site of a small deposit (e.g., 20 year) of high calorific content coal. Consequently, it has a capital cost (estimated at $389 million in 1984 dollars by the proponents) according to the MPP brochure (Wheelabrator, 1984, p. 20, as updated).

This is equal to $2,733/net kW installed in 1984. Of this cost, $2,100-$2,150/kW is attributed to the power plant itself. This project has yet to be financed.

Long-term demand for electricity in the Railbelt Region of Alaska has been forecast by the Alaska Power Authority. It is significant that this load forecast is conservative with respect to the forecasts made by the Railbelt utilities, as shown in Figure 3-1. The Alaska Power Authority load forecast, if the load were met with new coal-fired plants, results in the requirement for five additional 200 MW coal-fired power plants, each consuming about one million tons/yr of coal. (Alaska Power Authority OGP Model run.)

3.2 EXPORT DEMAND FOR ALASKA COAL

This section describes both near term (1985-1995) and long term export markets for Alaska coals.

3.2.1 Near Term Markets

Currently, Usibelli is under a 15 year contract with Hyundai/Suneel to ship 880,000 short tons/yr (800,000 metric tons/yr) to the Korean Electric Power Co. (KEPCO). This contract has spurred development of a coal handling and loading facility in the Port of Seward, financed with $12 million worth of tax exempt Industrial Revenue Bonds (Tarrant 1983). The Hyundai/Suneel contract may represent the tip of the iceberg in exports. Numerous studies have shown a vast steam coal export market in the Pacific Rim, and in the Free World as a whole.

This market has grown quickly since the mid-1970s as consumers in Japan, Korea, Taiwan, Hong Kong and elsewhere in the Pacific shifted away from oil tc coal. Most coal used in these countries must be imported. While coal is imported into these countries both for use in steel making and for use as fuel, only fuel used as "steam coal" is considered here. With rare exceptions Alaska coals of interest are suitable only for use as fuel. This use includes firing of electric utility and industrial boilers and in cement kilns.

A further indication of increasing coal demand is the announced constructio plans for new coal-fired boilers to be built in Japan as shown in Table 3-3 Recent and projected purchases of the Korea Electric Power Co. are summarized i Table 3-4. KEPCO has increased bituminous coal imports from 300,000 tons/yea in 1982 to nearly 6.0 million tons/year projected for 1985 and throughout th 1980's.

geologic reserves; but they are large countries with poor transportation networks, and consequently may import a small portion of their requirements if this proves more economical than transportation from inland sources.

In order to give the most conservative treatment to the import levels projected in this study, it has been assumed that the maximum feasible exploitation of known coal resources for each country examined. Also it has been assumed that these resources are developed speedily so that they are exhausted before imports begin. Since very little coal mining now takes place in the Philippines, Malaysia, and Thailand, there is little to be said about current production costs and trends or the difficulties likely to be encountered by bringing coal reserves into production in isolated areas such as Sarawak in East Malaysia. Therefore, the estimates presented yield an outside estimate of the potential domestic production.

Australia is included as a consumer in this study even though it will be a major net exporter. Because the supply-demand analysis must include the demand of all consumers in the market, domestic consumption of Australian coal must be considered. Only the demand estimated for New South Wales and Queensland is included; these two states produce all of Australia's coal exports and also supply their own internal requirements (Australian Dept. of Trade, 1983b). Other Australian states are self-sufficient in coal but not exporters.

Dames & Moore estimates of steam coal consumption for all consuming sectors and of domestic production for all Pacific region net coal importers are shown in Table 3-6. This table shows the demand, domestic production and net import estimates in Metric Tonne of Coal Equivalent (MTCE),[1/] a unit of energy content that provides a common basis for comparing coals of varying quality. This unit

1. The MTCE is the energy content of a metric ton (tonne) of coal that contains 12,600 Btu per pound. There are 27.8 million Btu per MTCE calculated as 12,600 Btu per pound multiplied by 2204 pounds per tonne or 27,770,440 rounded to 27.8. The consumption in each country, as estimated by SHCA, was expressed in actual tonnes; SHCA provided average Btu contents for coal used in each country so that they could be converted into MTCE. The conversion requires multiplyong the actual tonnes by the ratio of the actual calorific value, say 24 million Btu per tonne, to the calorific value of the MTCE, i.e., 27.8 million Btu. A similar conversion was carried out for the estimated domestic production in each country considered. (Wilson, 1980a).

is really a more familiar shorthand for the fundamental energy unit of calorific value, usually expressed in British Thermal Units (Btu's). The MTCE is based on 12,600 Btu per pound coal and is a more interpretable measure than estimates expressed in billions or trillions of Btu.

Dames & Moore's forecast is reinforced by a market assessment published by Diamond Shamrock (1983). Diamond Shamrock has shown that the Pacific Rim is the fastest growing market for coal in the world. This energy starved region must import 77% of its coal according to "The Cook Inlet Story." The Diamond Shamrock data shown in Table 3-5 support an estimated annual growth rate for the Pacific Rim market of 5.3%/yr when the market size is measured in tons (or Btus) of coal.

Table 3-6 shows that imports of coal consumers in the Pacific market will rise rapidly, particularly after the year 2000. Beginning at 96 million MTCE in 1990, imports (plus Australian demand) rise over threefold to 294 million MTCE in 2010, and in 2040 reach a level of 572 million MTCE annually. This tremendous growth in net imports will be mainly the result of increasing consumption, though depletion of domestic production in Korea, Japan, the Philippines, and Thailand will contribute to increased imports in the later years. Japan and Korea are currently the largest importers and will continue as such, taking 83 percent of all imports in 2010. Even in 2040, despite increases in newly industrialized countries such as Malaysia, Japan and Korea will still require 74 percent of imports in the Pacific.

As noted above, coal from Alaska will be used primarily for electric power generation. Estimates net imports for use in this demand sector also are shown in Table 3-7. The estimates of net imports for use in the electric power sector are also keyed to the consumption estimates.

The estimates of imports for use in electric power generation provide a more direct indication of the potential market for Alaska coal. From 60 to 65 percent of the total imports will be for electric power use, depending on the year. The size of this potential market for Alaska coal exports is impressive. For example, in 2000, an estimated 117 million MTCE of coal will be imported for power generation. Considering the difference in calorific value, this is equivalent to 210 million tons of coal of the quality found in the Beluga coal field. In later years (for example 2020), the total rises to 257 million MTCE of coal imports per year. The largest importers are Japan, Korea, and Taiwan. Sections 4.0 and 5.0 examine Nenana's and Beluga's ability to supply this Pacific Rim market.

ENERGY DEMAND FORECAST

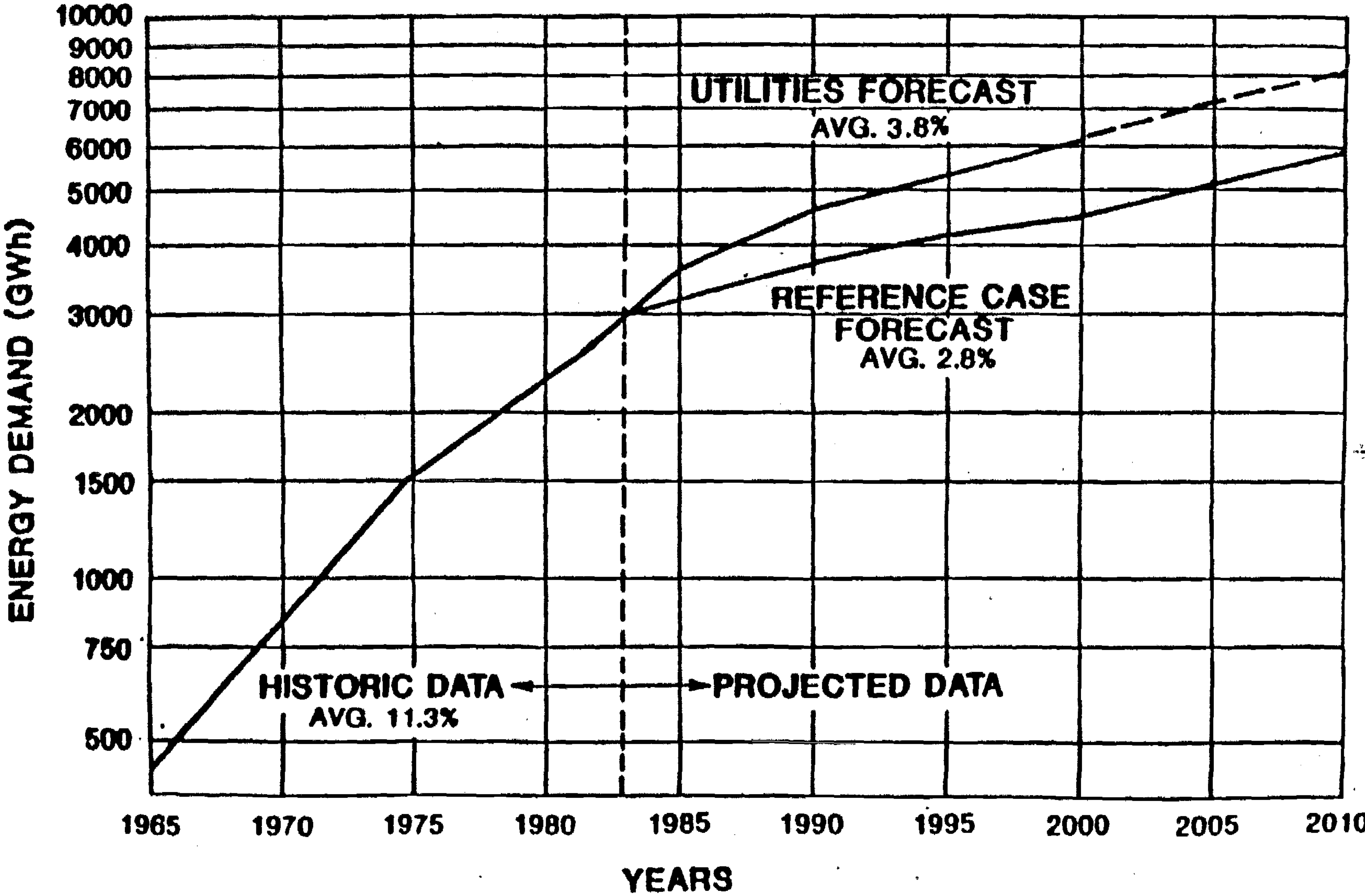

FIGURE 3-1

TABLE 3-1

CONSUMPTION OF COAL IN ALASKA

User	Year 1982	Year 1983/84
U.S. Government	417,000	420,000
Fairbanks Mun. Utility System	172,000	164,000
University of Alaska	58,000	60,000
Golden Valley Electric Utility	140,000	171,000
Storage	7,500	
Other and Miscellaneous	18,000	17,000
Total Consumption	802,000	832,000

SOURCE: Kentco 1984; Schmitt 1983

TABLE 3-2

COAL-FIRED CAPACITY IN ALASKA

Owner	Location	Capacity	Heat Rate (Btu/kWh)
Golden Valley Electric Assn.	Healy	25	13,200
University of Alaska	Fairbanks	13	12,000
U.S. Air Force Ft. Wainwright	Fairbanks	20	20,000
Fairbanks Municipal Utility System	Fairbanks	29	13,300 22,000
Total	N/A	87 -	12,000 - 22,000

SOURCE: Battelle, Vol. VI 1982; Alaska Utilities confirmation.

TABLE 3-3

COAL-FIRED PLANT CONSTRUCTION PLANS
IN JAPAN

Utility	Plant	Unit #	Capacity (MW)	Commissioning According to FY 1983 Plan
Hokkaido	Tomato-Atuma	2	600	Sept. 1985
EPCo.	Hara-Machi	1	1,000	Dec. 1991
Tohoku		2	1,000	After FY 1983
	Noshiro	1	600	Sept. 1990
		2	600	After FY 1993
		3	600	After FY 1995
Hokuriku	Turuga	1	500	Oct. 1990
Chugoku	Shin-Onoda	1	500	April 1986
		2	500	Feb. 1987
	Misumi	1	600	April 1993
		2	600	April 1994
Kyushu	Matsurra	1	700	Oct. 1987
		2	700	Oct. 1993
	Reihoku	1	700	Oct. 1990
		2	700	March 1993
EPDC	Matsurra	1	1,000	Oct. 1988
		2	1,000	Oct. 1993
	Ishikawa	1-2	312	June 1986 Dec. 1986
Soma Kyodo	Shinchi	1	1,000	April 1989
		2	1,000	July 1993
Joban Joint	Nakoso	8	600	Sept. 1983
		9	600	Dec. 1983
Others			2,000	March 1993

SOURCE: Japanese Government; Gordon 1984.

TABLE 3-4

KEPCO COAL PURCHASES
(thousand metric tonnes)

Year	Domestic	Foreign	
	Anthracite	Bituminous	Anthracite
1979	895	-	326
1980	1,362	-	407
1981	1,432	-	369
1982	2,168	314	198
1983	2,256	1,310	-
1984	2,315	4,764	-
1985	2,148	5,813	-
1986-1990 (Average/yr)	1,565	6,029	-

SOURCE: Gordon 1984.

TABLE 3-5

DIAMOND CHUITNA MARKET
PROJECTED STEAM COAL DEMAND[1/]
(Million Metric Tons Per Year)

Market Area	1985	1990	1995
West Coast USA	3-4	4-5	4-8
Hawaii	0.0	0-4	0-4
Alaska	1.0 (1.8-2.1%)[2/]	1-3 (1.5-3.5%)[2/]	1-4 (1.3-4.0%)[2/]
Japan	20-25	28-34	33-39
Korea	8-9	10-12	13-14
Taiwan	10-11	15-16	18-19
Hong Kong	5.0	8-11	8-12
Total	47-55	66-85	77-100
Total Pacific Rim 72-84		43-50	61-73

1/ Based on mid-1983 studies by JIEE, WCEC and DSC.
2/ Percent of Total

SOURCE: Diamond Shamrock Corporation, Diamond Chuitna Briefing Document June, 1984.

TABLE 3-6

PACIFIC RIM COAL DEMAND 1985 to 2050
MILLION METRIC TON COAL EQUIVALENT

	Note	1985	1990	2000	2010	2020	2030	2040	2050
Australia									
GNP Growth Ann %		2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Electric Total:	a	45.8	46.1	50.6	53.1	55.8	58.7	61.7	64.8
New Coal	a,b	36.4	37.6	38.8	40.1	41.5	42.9	44.4	46.0
Replace w Coal	a,k		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cement	a,m	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Synfuel	a,c				2.7	5.4	8.1	8.1	8.1
Indust. Steam	a,l	4.7	4.9	5.4	6.0	6.6	7.3	8.1	8.9
Coal Demand		42.1	43.5	45.3	49.8	54.5	59.3	61.6	64.0
Export Demand		21.1	21.8	22.6	24.9	27.2	29.6	30.8	32.0
Japan									
GNP Growth Ann %		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Electric Total:	d	218.1	240.8	265.9	293.6	324.1	357.9	395.1	436.2
New Coal	b,d	18.1	29.5	42.0	55.8	71.1	88.0	106.6	127.2
Replace w Coal	f,d			35.2	70.3	105.5	105.5	105.5	105.5
Cement	d,m	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Synfuel	c,d				25.0	50.0	75.0	75.0	75.0
Indust. Steam	d,l	3.1	3.3	3.6	4.0	4.4	4.9	5.4	6.0
Coal Demand		28.7	40.2	88.2	162.6	238.4	280.8	299.9	321.0
Korea									
GNP Growth Ann %		7.0	7.0	7.0	4.0	4.0	2.0	2.0	2.0
Electric Total:	s,g	21.2	29.7	58.5	86.6	128.2	156.2	190.4	232.1
New Coal	b,s	6.6	10.8	25.2	39.3	60.1	74.1	91.2	112.0
Replace w Coal	f,s			2.1	4.1	6.2	6.2	6.2	6.2
Cement	e,h	3.4	4.8	9.4	9.4	9.4	9.4	9.4	9.4
Synfuel	c,j				3.4	6.7	10.1	10.1	10.1
Indust. Steam	e,i	2.1	2.5	3.5	4.3	5.2	5.8	6.4	7.0
Coal Demand		12.1	18.1	40.2	60.4	87.6	105.5	123.2	144.7
Taiwan									
GNP Growth Ann %		5.0	5.0	5.0	4.0	4.0	4.0	4.0	4.0
Electric Total:	t,j,g	18.1	23.1	37.6	55.6	82.4	121.9	180.5	267.1
New Coal	b,t	3.0	5.5	12.8	21.8	35.2	54.9	84.2	127.6
Replace w Coal	f,t			3.9	7.7	11.6	11.6	11.6	11.6
Cement	e,h	2.1	2.7	4.4	4.4	4.4	4.4	4.4	4.4
Indust. Steam	e,i	2.1	2.4	2.7	3.0	3.4	3.7	4.1	4.5
Coal Demand		7.2	10.6	23.7	36.9	54.5	74.6	104.3	148.0

TABLE 3-6 (Continued)

PACIFIC RIM COAL DEMAND 1985 to 2050
MILLION METRIC TON COAL EQUIVALENT

	Note	1985	1990	2000	2010	2020	2030	2040	2050
Sing. & Malay									
GNP Growth Ann %		7.0	7.0	7.0	5.0	5.0	4.0	4.0	4.0
Coal Demand	n,o,p	4.0	5.5	7.8	9.5	11.6	12.8	14.2	15.6
Total Demand		73.0	96.2	182.5	294.4	419.3	503.3	572.3	661.4
Total Production Excluding Australia		33.0	33.0	32.0	16.0	16.0	16.0	3.0	3.0
Net Imports		40.0	63.2	150.5	278.4	403.3	487.3	569.3	658.4
Cumulative Imports	q	0.0	516.1	1,584.1	3,729.2	7,137.6	11,590.9	16,874.1	23,012.6

SOURCE: Dames & Moore Calculations.

Notes:
a = OECD 1985. Energy balances 1983/1983. P.29. Electrical growth at half the GNP growth rate.
b = Assumes that 50 percent of the electric demand growth is supplied by coal-fired plants.
c = Assumes that coal to synfuel projects provide up to 10 percent of the current oil and gas consumption
d = OECD 1985. Energy balances 1983/1983. P.77. Electrical growth at half the GNP growth rate.
e = WESTPO 1981. Western Coal Exports, Final Report. P. 22. Electrical growth at GNP growth rate.
f = Assumes that all 1985 oil and gas fired generation is replaced by coal during the period 2000-2020.
g = Electrical demand is assumed to grow at the GNP growth rate.
h = Coal demand for cement production grows at the GNP rate through 2000 then is flat.
i = Assumes industrial steam coal demand grows at the GNP growth rate: half of the growth is fueled by coal.
j = WESTPO 1981. Western Steam Coal Exports to the Pacific Basin. Demand Task Group, P. 14.
k = Assumes no replacement of oil and gas fired capacity with coal in Australia.
l = Coal demand assumed to grow at 25 percent of the GNP growth rate.
m = Assumes flat demand for coal in cement production.
n = Malaysian coal demand in 1985-90 based on Mann et al, 1983. ASEAN COAL. Table 1.1, P. 2.
o = Singapore Coal demand in 1985-90 based on WOCOL forecasts in ICF, 1980. Table S-3, P.4-115.
p = Demand for 1990 to 2050 is assumed to grow at half the GNP growth rate.
q = Calculated as the arithmetic average of each column and the previous column times ten, plus the previous column
r = Assumes that half the Australian coal demand is in potentially exportable locations.
s = Based on 1984 data provided by H. Cheung, KEPCO B.C. to M. Feldman, D&M, 8/85.
t = Taiwan power, September 1984, Unpublished generation plan.

TABLE 3-7

COAL CONSUMPTION1/ DOMESTIC PRODUCTION1/
AND NET IMPORTS FOR THE USE IN THE
ELECTRIC POWER SECTOR FOR PACIFIC MARKET IMPORTERS
1990-2040
(million MTCE)

	1990	2000	2010	2020	2030	2040
MALAYSIA AND SINGAPORE						
Demand	6	8	10	12	13	14
Domestic Prod.	0	1	1	1	1	0
Net imports	6	7	9	11	12	14
JAPAN						
Demand	29	77	126	177	193	212
Domestic Prod.	10	8	5	5	5	
Net imports	19	69	121	134	188	212
KOREA						
Demand	11	27	43	66	80	97
Domestic Prod.	2	2				
Net Imports	9	25	43	66	80	97
TAIWAN						
Demand	6	17	30	47	67	96
Domestic Prod.	1	1	1	1	1	1
Net imports	5	16	29	46	66	95
TOTAL IMPORTS	39	117	202	257	346	418

1/ Dames & Moore estimates.

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4.0 NENANA COAL FIELD SUPPLY AND PRICE ANALYSIS

The Nenana field is treated first, beginning with a description of the field, because Nenana is producing coal. Detailed discussions of Nenana coal demand, supply, and price are included.

4.1 NENANA COAL FIELD CHARACTERISTICS

The Nenana coal field is a vast deposit of subbituminous coal in the center of the Railbelt Region. It is located in an area about 200 miles north of Anchorage and 60 miles south of Fairbanks. Estimates of the size of this field are shown in Table 4-1. The coal field consists of six noncontiguous individual coal-bearing areas extending in a belt up to 30 miles wide including the Healy Creek, Lignite Creek, Jarvis Creek, Wood River, Tatlanika, and Teklanci fields (Schaff & Merritt, 1983).

The Nenana resources are contained in multiple seams of low sulfur, subbituminous coal. Seam thicknesses range from 2.5 to 60 feet. The coal bearing strata are comprised of moderately consolidated sandstones and siltstones which have been folded and faulted. Discontinuous occurrences of permafrost are present in the area. The attitude of the beds ranges from flat at the axes of the synclines and anticlines to steeply dipping on the flanks of the folds. The surface material is composed of weathered bedrock with peaty layers at the immediate surface and alluvial deposits in the stream beds. The topography is quite rugged in the vicinity of the streams and moderately steep-to-gently rolling on the upland areas between the watercourses. Vegetation ranges from spruce and hardwood forest to barren ground with some areas of tundra (Roy Merritt, Alaska DGGS, personal communication to J. Popp, April, 1984).

The Nenana field is large; however, the coal is of modest quality. For example, the coal being mined and shipped to Fairbanks Municipal Utility System has the following characteristics:

Harza-Ebasco and Dames & Moore have considered the quality of coal that would probably be mined if Nenana field production were expanded from its current level to 4 million tons/yr. That coal would probably have the following characteristics:

HHV	7,600 Btu/lb
Moisture	26 percent
Ash	8.3 percent
Sulfur	0.20 percent

The sample data used for this determination are shown on Table 4-2.

Beyond the expansion of Nenana field mining capacity from 2.0 to 4.0 million tons/yr, general field conditions are assumed to hold. The quality of the coal, in general, is considered to be as follows:

HHV	8,100 Btu/lb
Moisture	24 percent
Ash	10.7 percent
Sulfur	0.2 percent

This is based upon data contained in Rao and Wolff (1980).

There are six major leaseholders in the Lignite and Healy Creek basins as shown in Figure 4-1. All of the prime coal resources in the area are under lease. Usibelli with four large noncontiguous tracts is the largest leaseholder. Amax Coal and Arctic Coal also control sizeable holdings. Renshaw, Shallot, and Citro hold smaller leased areas. Amax Coal holdings are particularly distant from the Suntrana loadout.

Usibelli Coal Mine (UCM) is the only producer in the Nenana field. UCM is now mining at the Poker Flats mine on Lignite Creek, as shown in Figure 4-2.

Proximity to transportation infrastructure is an important factor in the Nenana area. Because of the field's location near Denali National Park, it is classified by EPA as a Class I airshed which has very strict air quality restrictions. Location of a major power plant or other large coal-burning industry is effectively precluded. Therefore, major users of Nenana coal must rely on truck or rail transport to move the coal to the point of use. UCM at Poker Flats is served by an existing rail spur from the main line of the Alaska Railroad (which follows the Nenana River) to a coal-loading facility located at the abandoned Usibelli works at Suntrana. The coal is trucked several miles from Poker Flats to Suntrana.

4.2 DEMAND FOR AND SUPPLY OF NENANA FIELD COAL

Nenana field coal from UCM is now being shipped to both domestic and foreign markets. The domestic market centers around Fairbanks, Alaska. UCM also ships coal to Korea under a contract with Suneel, a Korean importer. As part of the thermal alternative to Susitna the Nenana coal could be used to supply up to 400 MW of new coal-fired capacity to be built near the town of Nenana.

4.2.1 Demand for Nenana Coal

Usibelli's current domestic customers include Fairbanks Municipal Utility System, Golden Valley Electric Association, the University of Alaska, Fairbanks, and Fort Wainwright. Total Alaska consumption in 1983 was 832,000 tons. Export coal is shipped to KEPCO under the Suneel contract, through the Port of Seward. This contract provides for sale of 800,000 metric tons/yr, or 880,000 short tons/yr (Alaska J. Commerce Vol. 8, No. 8, 2-20-84).

Of particular interest is projected use of Nenana coal if Susitna is not constructed. The cumulative total consumption for the 400 MW of capacity in the Nenana field area, over the 58-year period 1993 to 2051, is estimated at 100 million tons of coal. If these values are added to existing coal consumption during the estimated life of the Suneel contract and existing coal-fired units, coal demand in the Nenana field may peak at about 3.5 million tons/yr in the late 1990s. (Dames & Moore estimates based on Alaska Power Authority OGP Model runs.)

Of the 3.5 million tons/yr at the peak, it is estimated that about 2.5 million tons or slightly over 70 percent of total production would be for the domestic market. The Nenana field will be mined predominantly for Alaska needs.

4.2.2 Nenana Coal Supply

The reserves of the Nenana coal field are more than adequate to support the level of production associated with additional thermal plants and Suneel exports for a very long period of time. UCM controls about 25,000 to 30,000 acres of land in the Healy Creek and Lignite Creek areas along the Nenana River near

Healy. UCM estimates its total recoverable reserves to be about 80 million tons.

Since 1976, UCM has extracted coal from three seams in the Poker Flats area on the south side of Lignite Creek. It is estimated that 28 million tons of recoverable coal occur in this area at a stripping ratio of about 4.5:1 (bank cubic yards of overburden to tons of coal) (Denton 1981). Normally, only two seams are recovered to economize cycling of the dragline operation. The uppermost seam, the No. 6, is about 20 feet thick and occurs about 140 feet above the No. 4 seam, which averages 22 to 23 feet in thickness. When the No. 6 is absent, the No. 3 seam, which averages 17 to 19 feet in thickness and 90 feet in depth below the No. 4 seam, is taken with the No. 4 seam.

As reserves are exhausted in the Poker Flats area, plans are to move the mining to the north side of Lignite Creek (termed the Two Bull Ridge area) where 38 million tons are estimated to occur at a stripping ratio of 3.6:1 (Denton 1981). Additional reserves have been identified farther east of Two Bull Ridge in an area called Gold Run Pass. Due to logistics, this mining area has been idled in order to take advantage of the short haulage involved with the Poker Flats area.

UCM utilizes a Bucyrus-Erie 1300 W walking dragline with a 33-cubic yard bucket on a 325-foot boom. The recent purchase of large haul trucks and the excess capacity now available with the dragline could enable UCM to expand production easily to as much as two million tons per year (C. Boddy, R. Hundrup, G. Lightwood and J. Usibelli Jr., of UCM, personal communication to J. Popp, Dames & Moore, 4-84). It is conceivable that UCM could further expand its annual capacity with the emplacement of new mining equipment in the Two Bull Range and/or Gold Run Pass areas. Mining costs, assuming similar mining methods and stripping ratios, should be similar to current costs, although haulage costs would increase as mining progressed away from the tipple at the mouth of Lignite Creek.

The data above describe the present UCM operations. If demand develops along the lines previously discussed, coal production may have to be expanded by some 1.8 million tons/yr. UCM has stated that it could double mining capacity to some 4 million tons/yr. The presence of other leaseholders makes future production in the area not a serious constraint. UCM is probably the most logical candidate for such expansion at the present time due to the economics that could be achieved from the existence of shops, a large rail loading facility, and other investments at the present operations. The cost of such an expansion is examined later in this section. The Nenana field, then, can provide the production necessary to support increased power generation in Alaska.

4.3 NENANA COAL PRICE AND PRICE ESCALATION

The demand for, reserves of, and production possibilities associated with Nenana field coal make pricing the final question of concern. There are four essential questions to be answered: 1) what pricing concept is most appropriate; 2) what base mine-mouth price of coal should be used; 3) what base cost of transportation should be used; and 4) what real escalation rates are appropriate for Nenana field coal?

4.3.1 The Appropriate Pricing Concept

As noted in Section 2.0, there is one coal producer in the Nenana coal field and only five large consumers (Suneel, U.S. Department of Defense, Fairbanks Municipal Utility System, Golden Valley Electric Association, and the University of Alaska). These are not, in any sense, the conditions for a perfect market. Not surprisingly, current prices for UCM show a broad range, as demonstrated in Table 4-3.

The terms associated with each price shown in Table 4-3 differ. For example, the Fort Wainwright contract price is a delivered price. The coal must be crushed and shipped to Fairbanks. At the other extreme, the GVEA contract does not get involved in crushing the coal or transporting it to the power plant. GVEA is responsible for all such activities.

The U.S. Department of Defense contract is the most recent contract negotiated. If one assumes a 1983 cost of transporting coal from Suntrana to Fairbanks of $0.50/million Btu (Sworts 1983), then the federal government is paying about $2.40/million Btu at the mine mouth.

This range of prices is sufficiently broad to conclude that the coal being sold by UCM is not always sold under long-term contract at production cost. The long-term contract price, at the minimum, may reflect production costs of the time of the contract negotiation. Alternatively, the long-term contract may contain a price higher than the full cost of production if such a higher value represents the notion of a "market value" or "market clearing price" between a willing buyer and a willing seller.

The range of prices for coal sold from UCM demonstrates the indeterminate nature of commodity prices in a small market. Prices are set by bilateral negotiation, in this case by a monopoly seller and oligopsony buyers: one coal seller and five large coal buyers. It was decided, however, that a full production cost analysis would be useful, recognizing that such an analysis would be quite conservative basis for coal valuation and would understate the long-term market price of coal in Nenana. While production costing represents the floor, it is the only analytic basis upon which to estimate future Nenana prices.

4.3.2 The Production Cost of Nenana Coal

Harza-Ebasco hired the Paul Weir Company (Weirco), a respected mining engineering company, to prepare an independent estimate of the production cost of a new mine in the Nenana coal field. This production cost takes into account known features of the existing Usibelli Coal Mine, Inc. mine. However, any detailed geologic information and mining plans which UCM may have are not public. It was therefore necessary to use information from public sources to determine the geologic conditions which would likely prevail were UCM to expand or a new mine to be opened in the area. Because mining methods and costs depend on the geology of the deposit, it was necessary to prepare a fairly detailed hypothetical description of the geology. Every effort was made to make the assumptions realistic and representative of conditions which would be seen for the next expansion of production to take place in the area (since conditions vary widely throughout the Nenana coal field). All of the data on production costs and technology, as presented below, come from Weirco, 1985.

Based on the assumed geology and the mining methods now in use at UCM a detailed mining plan was developed. From the mining plan were derived estimates of capital and operating costs over the 20-year assumed mine life. These costs were then incorporated into a discounted cash flow (DCF) calculation. Using a projected inflation rate of 5.5% per year between now and 2050 for operating costs (no real increase included) as determined by the Alaska Power Authority and a real discount rate of 8.2% per year, a levelized revenue requirement for the combined capital and operating costs was determined. This levelized revenue requirement corresponds to the minimum price which would be acceptable to a coal producer to justify investing the capital necessary to open a new or expanded mine. The Weirco findings are summarized below. Details of this analysis are contained in the Weirco report.

4.3.2.1 Geology of Hypothetical Coal Deposit

The hypothetical Nenana coal field deposit assumed for this study contains three minable seams designated: B, I, and T (Bottom, Intermediate, and Top). A representative cross-section is shown in Figure 4-3. The seams occur within Figure 4-3 goes an area of lightly indurated sandstones and moderately consolidated siltstones. All three seams outcrop along a valley and dip into the valley wall at 8 to 13 degrees (averaging 10 degrees). The deposit consists of two areas (X and Y) separated laterally by approximately 10,000 feet of noncoal bearing area. In Area X, the bottom seam averages 20 feet in thickness, the intermediate seam 30 feet, and the top seam 22 feet. The bottom-intermediate seam interval is 75 feet, and the intermediate-top seam interval is 140 feet. The total area between the bottom outcrop and 300 feet depth on the top seam covers 850 acres and contains approximately 44 million tons in place.

Area Y contains the same seams, with average thicknesses being: bottom seam 18 feet, intermediate seam 30 feet, and top seam 15 feet. The average interval thicknesses are: bottom-intermediate 90 feet and intermediate-top 120 feet. Area Y covers 900 coal-bearing acres and contains 35 million tons of coal in place.

4.3.2.2 Mine Capacity

Mine plans and cost estimates were developed for two possible mines: a 2,000,000 ton/yr hypothetical expansion of an existing mine and a new 3,000,000 ton/yr mine. UCM could expand production from its maximum (with present equipment) of 2,000,000 tons/yr to 4,000,000 tons/yr and still take advantage of presently underutilized support facilities such as the Suntrana rail loading facility. This is a logical development. Were more coal required a new, free-standing, 3,000,000 ton/yr mine could be built. These two alternatives cover the anticipated range of requirements for coal from the Nenana field.

4.3.2.3 Mining Methods and Equipment

Two Million Tons/Yr - Incremental Production Case

A combination of dragline plus loaders and trucks was chosen for this case. All overburden and innerburden must be drilled and blasted prior to stripping. Front-end loaders and trucks remove the upper overburden and innerburden zones ahead of the dragline. The dragline will strip the bottom seam in the simple sidecasting mode. As the intermediate seam is encountered, the dragline will strip up to 60 feet of cover on the intermediate seam and then move down on the bottom seam innerburden and strip that seam. This involves some extended bench rehandling. After reaching the 300-foot depth on the bottom seam, that seam will be abandoned, and the dragline will strip the intermediate seam (and eventually the top seam) in a single seam operation to a maximum of 100 feet of cover. The dragline will carry a 30 cubic bucket and have a 300-foot operating radius.

The project area is Area X of the Nenana hypothetical deposit. This area contains sufficient reserves at an attractive stripping ratio. It is also closer to the assumed coal delivery point than Area Y, thus shortening haulage cycles, as well as haul road and power line construction.

The area was subdivided into four pit areas. Two 100-foot wide strips (two 100-foot dragline cuts) were laid out in the areas amenable to dragline stripping. In the other areas, 400-foot square blocks were laid out for loader-truck mining. The quantities of coal, overburden, innerburden and parting were calculated for each area. Maximum mining depth was set at 300 feet.

Initial stripping begins with the dragline making a box cut at the bottom seam cropline in the eastern portion of the area. By the third year of production, the loader-truck fleet begins operation in the central part of Area X and commences prestripping ahead of the dragline in the eastern portion. The sequence continues until the tenth year, when the dragline moves over to the bottom seam cropline in the western portion of the area and strips downdip through the remaining project life. The loader-truck operations are maintained approximately one year in advance of the dragline stripping. Average run-of-mine quality is assumed to be 7,600 Btu/lb.

Equipment requirements follow from the choice of the basic mining method and the quantities of overburden and coal to be handled. For example, the dragline size is determined from the number of yards of overburden to be moved by the dragline and the number of operating cycles per shift which the dragline can perform. Similar "units of work" calculations were performed to determine the number and size of drills, loaders, dozers, trucks, and other major equipment items. The equipment items for the 2 million ton/yr incremental case are shown in Table 4-4.

Three Million Tons/Yr - Staged Production Increase Case

This case is mined in a similar manner as the 2 million ton/yr case. Front-end loaders and trucks strip in advance of the 30 cubic yard dragline. The tonnage requirements necessitate utilizing both Area X and Area Y for this study. The pit layout for Area X is identical to that used in the case above. In Area Y, 200-foot wide strips were laid out for four pits, and the coal and waste quantities were calculated for each strip.

The operation begins in the eastern portion of Area Y, with the dragline box cut on the bottom seam. Loader-truck prestripping begins in the second year and continues about one year in advance of the dragline. By year 7, the dragline moves to the western portion of Area Y and finishes stripping there in year 13. Then it is moved to the eastern part of Area X and finally finishes up in the western part. The production level begins at one million tons/yr, then increases to two million tons in the third year, and to three million tons in the ninth year of production. The average heating value is assumed to be 8,100

Btu/lb, as mined. The list of major equipment items is identical to that for the 2 million ton/yr case.

4.3.2.4 Capital Costs

Representative models of equipment sized to perform the work required were selected for cost estimating. Equipment prices were based on January, 1985 budget level estimates from the authors' files adjusted to include freight and erection costs; a five percent contingency allowance was added to the price of each item of equipment.

The estimated price of tires on rubber-tired equipment items was subtracted from the unit capital cost to arrive at the depreciable base. No allowance was made for salvage value. An estimate of the service life of each item of major equipment was made based on manufacturers' recommendations and the estimated severity of the work load.

The cost of mine infrastructure items, including offices, shops, warehouses and coal-handling facilities, as well as site preparation were estimated based on the equipment fleet requirements and personnel levels at the mines. Townsite costs were provided by H-E based on projected manpower levels. Costs for mine infrastructure were developed from information in the authors' files. A 15 percent contingency allowance was included in the infrastructure costs.

The costs of exploration and lease acquisition, developmental drilling and engineering, and mine permitting were estimated based on the size of the hypothetical deposit. A contingency allowance of 15 percent was included in these estimates. These costs were amortized over the tons of coal produced. Preproduction operating expenses of the mine, such as initial stripping and haul road construction, were also amortized over the tons of coal produced by the mine.

4.3.2.5 Operating Costs

All costs are estimated in January, 1985 dollars. Labor rates are based on the labor agreement at the UCM near Healy, Alaska. Hourly rated personnel are separated into five pay grades, based on the classifications in that agreement.

Direct wages and salaries used in all the case studies are shown in Table 4-5. Labor overhead costs (fringe benefits, payroll taxes, etc.) were uniformly estimated to be 40 percent of direct wages and salaries.

The costs of repair parts, operating supplies, and fuel and lubricants were estimated for the major equipment items used in each mine plan. Maintenance labor requirements per shift operated were also estimated. Productivity estimates for the major excavating machinery (draglines and shovels) were based on estimates of availability. Other major items of equipment were scheduled to operate a maximum number of shifts per year based on estimated availabilities.

4.3.2.6 Mine Levelized Revenue Requirement

The minimum levelized coal sale prices were estimated based on the revenues necessary to cause net cash flows after taxes to become zero at the beginning of Year 1, when discounted at a real internal rate of return of 8.2 percent. This rate of return (discount rate) was selected by H-E based on the cost of capital for coal mining companies, as determined by an examination of recent mining company financial data. The details of this analysis are set forth in Appendix A. The total cost of production includes the following:

1. The direct operating costs.

2. Royalty at an assumed rate of 12-1/2 percent on realization on all coal mined.

3. Alaska Mining License Tax beginning in the first year of production for the incremental 2 million ton/yr case and beginning in the fourth year of production for the alternative case. (The tax is $4,000 plus seven percent of gross profit in excess of $100,000 before federal income tax, but after depletion allowance.)

4. Service life depreciation.

The total cost of production for calculation of federal income tax, hence after tax cash flows, includes the following:

1. The total cost of production described above.

2. Accelerated depreciation was substituted for service life depreciation, and it was calculated from the capital cost schedule using the accelerated cost recovery system property classes and reduced by one-half the investment tax credit.

3. Accounting for any tax loss carried forward.

4. Percentage depletion equal to 8.5 percent of realization minus royalty with a maximum of 50 percent of gross profit, the statutory depletion allowance of ten percent was reduced by 15 percent because the adjusted basis of the property is relatively insignificant.

5. A federal income tax liability calculated at a flat rate of 46 percent.

6. An investment tax credit was taken in the year capital items were purchased (items with a three-year life yielded a six percent investment tax credit, longer lived items, a ten percent investment tax credit).

An annual stream of cash flow requirements was generated by the Paul Weir model. This stream of cash flow requirements was deflated by the APA long term inflation factor of 5.5% to arrive at real 1985 cash flow requirements and prices for every year. These annual prices were then levelized using conventional methodologies (see, for example, Leuing and Durning, 1977) and the real discount rate of 8.2%. The results of this analysis are shown in Table 4-6. Because the 2 million ton/yr case is considered more probable, and because it results in a lower minimum sales price than the other case, it has been chosen for subsequent H-E analyses. The resulting base price is $1.45/million Btu (1985 dollars).

The reasonableness of the $1.45 value, at the mine mouth, can be seen from comparison to the range of prices currently being paid for Usibelli coal. This value is above the mine mouth price being paid by GVEA ($1.30/million Btu), but it is slightly below the mine mouth price being paid by FMUS ($1.56/million Btu), and is well below the mine mouth price being paid by the U.S. Department of Defense, as previously discussed.

4.3.3 Nenana Coal Cost Escalation

(Dames & Moore, 1985, Section 2.0, passim)

For planning purposes, it is essential to forecast real coal cost escalation over time. While there are statements that coal prices will not escalate in real terms over time, such arguments are not consistent with the historical record. Consequently, Dames & Moore (1985) performed a detailed assessment of coal price escalation.

Historical data support the fact that real coal prices have trended upward throughout the 20th century. Figure 4-4 illustrates this escalation. Data for real coal prices were obtained from a time series of bituminous coal prices compiled by the U.S. Department of Commerce.[1/,2/] This series, which extends back to the beginning of the century, expresses bituminous coal prices in nominal dollar terms. These nominal costs were corrected to eliminate the effects of changes in the value of the dollar using the Wholesale Price Index.[3/,4/] The data in Figure 4-4 reflect this correction. Overall, between 1900 and 1980, real coal prices have escalated at an average compound annual rate of 1.2 percent. Even prior to the dramatic price rise in 1973, coal prices from 1900 to 1973 escalated at a real annual rate of 0.8 percent.

Historically, the factors driving the real price escalation of coal include real labor cost escalation, price escalation of substitute energy sources, and resource depletion effects. Countering the trend toward increasing coal prices are increases in productivity which occurred as large-scale mechanized surface mining techniques replaced labor-intensive underground mining. Despite these

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1/ U.S. Department of Commerce, 1971, Historical Statistics of the U.S. Colonial Times to 1970. Part I (For 1910-1970) Series M96.

2/ Ibid., 1983 Statistical Abstract of the U.S. 1982-83, p.715, Table 1278 (for 1970-81).

3. Op. cit. Note Series E23, p. 199 (For 1910-1970).

4. Op. cit. Note 2, Table 751, p. 456 (For 1971-1982)

cost-saving productivity increases, real coal prices have elevated steadily.

There is good reason to expect this trend to continue into the next century; the forces causing the escalation will likely continue, while the productivity increases (which tend to lower prices) may occur at a lower rate.

Because of the evidence of increasing coal prices over the past 80 years (a period comparable to our time horizon), an analysis of factor costs was made focusing on such cost components as labor, energy, royalties, and other operating costs. If labor and other costs increase over the project life it will be reflected in the price of coal. This is recognized in the structure of utility coal contracts. Agreements between coal suppliers and electric utilities for the sale/purchase of coal are usually long-term contracts, which include a base price for the coal and a method of escalation to cover cost of mining increases in future years. The base price provides for recovery of the capital investment, profit, and operating and maintenance costs at the level in existence when the contract is executed. The intent of the escalation mechanism is to recover actual increases in labor and material costs from operation and maintenance of the mine. Typically, the escalation mechanism consists of an index or combination of indices such as the producer price index, various commodity and labor indices, and consumer price index applied to operating and maintenance expenses, and/or regulation-related indices. These characteristics are exhibited by the Usibelli contracts with FMUS and GVEA (FMUS 1976; Hufman 1981).

In addition to price escalators, long-term coal contracts typically include "price reopener" clauses. These clauses allow renegotiation of the base price if some agreed-upon measure of coal market prices falls above or below a predetermined level. These clauses protect both utilities and coal producers against major fluctuations in market prices resulting from forces beyond either party's control, such as major supply disruptions or unusually severe swings in the business cycle. Price reopeners are becoming more common because coal prices have been fairly unstable over the last decade and because mining companies do not want to be "locked in" to current market prices that may not reflect longer run prices.

From the above discussion, it is clear that the coal supply contract would reflect changes in operating costs, including labor costs and energy supply costs and royalties. Each of these categories is discussed below. The following analysis attempts to forecast future coal mine revenue requirements.

4.3.3.1 Labor Rates

(Dames & Moore, 1985, p. 11-18)

Long-range historical data indicate that for the past 70 years real U.S. wage rates have risen both in the bituminous coal industry and in all U.S. industries. There is good reason to believe that the trend will continue for the next 70 years. Rising wages are a basic reflection of improving prosperity.

Figure 4-5 shows the real wage rates for bituminous coal workers and all industries from 1910 through 1981. The nominal dollar wages from annual statistics (compiled by the U.S. Department of Commerce Bureau of Labor Statistics) were corrected for changing prices using the Consumer Price Index. The hourly wages shown on Figure 4-5 are thus real (constant dollar) 1983 equivalents. There is a very definite upward trend in both wage series although bituminous workers consistently receive higher wages than the all-industry average.[1/] (Dames & Moore, 1985, Table 2-2).

A statistical procedure was used to establish the historic trend in wage rates. First, a log transformation was performed on both wage series to yield the annual rates of change. These transformed series were then regressed against time using an ordinary least square (OLS) linear regression. The coefficient of these regression lines indicates the best fitting linear (in logs) estimate of this annual rate of change.

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1. The U.S. wage data for the bituminous coal industry and all manufacturing are used as proxy for Alaska coal (which is subbituminous) because of the lack of Alaskan coal industry wage data. Information on coal wages in Alaska is not publicly available according to the Alaska Division of Labor. The only available series for Alaska is called Other Mining, which includes all nonpetroleum mining activities. Even this series is only available after 1971. Long-term publicly available data on subbituminous coal or lignite mining wages for the U.S., as a whole, are also lacking, since such coal has not been mined in significant quantities in the U.S. Therefore wage series for the U.S. bituminous coal industry and for all industries are used as proxies for Alaskan coal industry wages throughout this analysis.

Both the bituminous and all-industry series yielded a regression coefficient of 0.022 on the wage variable, i.e., a 2.2 percent average annual rate of change. An R square test was used to determine how well the derived trend line fits the observed data. For both wage series, a 95 percent correlation was obtained, indicating a very close fit (a perfect fit is 100 percent). Thus, the historical real wage rate has increased 2.2 percent per year for the past 70 years, whether all industry or bituminous industry wages are considered. This rate of increase is projected to continue through 2050.

4.3.3.2 Wages and Productivity

(Dames & Moore, 1985, p. 6-10)

It is frequently argued that productivity increase will overcome wage increases to the point that there is no net impact on product costs. Certainly labor costs are a large part of coal production costs wages can be offset by increases in labor productivity. Productivity increases can occur due to improved mining methods and equipment. Figure 4-6 represents productivity between 1948-1983 in the U.S. coal mining industry; surface mining productivity increased at an average rate of 3.2 percent per annum through 1973. This increase was due to a shift to better mechanized production and larger and more powerful equipment in surface mines. However, such trends are not without limit and may even be reversed. Starting in 1966, United States surface mine productivity began to level off and then to decline; this was well before the imposition of stringent reclamation regulations. The effects of more stringent safety and environmental regulations, along with labor force changes and other factors, led to a 1.8 percent per annum decline in U.S. surface mining productivity from 1973 to 1983. Though reclamation requirements are already fairly strong, increased regulation is possible and may tend to offset further productivity gains achieved through better technology. Figure 4-6 suggests, on balance, that productivity in surface mining was flat during the 1960s, declined in response to regulations and is flat now at a lower level of productivity.

To translate labor rate increases into coal mining unit cost increases net of productivity gains recognizes explicitly that other factors beyond labor utilization and wages act on mining costs. Increased regulation, taxation, and depletion are important considerations. These three factors act to raise unit costs, while only productivity gains act to lower cost. Clearly, as Figure 4-6 shows, real coal prices rose from 1900 to 1973 (at 0.8 percent annually) despite large technological improvements in mining. Thus, we estimate that the trend in unit labor costs will continue to raise the real cost of coal mining. Productivity increases, if any, are not expected to overcome the effects of increased regulation, taxation, and depletion. At best, overall labor productivity will remain flat, so that any real wage escalation will affect unit production costs.

4.3.3.3 Energy Costs

(Dames & Moore, 1985, p. 18-19)

The price of energy inputs used in coal mining has a small but significant effect on production cost. Two energy sources predominate--diesel fuel and electricity. Both of these sources are projected to escalate in real terms from 1983 to 2050, thus inducing a real escalation of coal mining costs.

According to the Alaska Power Authority composite oil price forecast, the 1983 constant dollar price of diesel fuel delivered in the Railbelt area is projected to rise at an average annual rate of 1.6% (real) from 1985 to 2020. In 2020 diesel prices are projected to level off due to competition from synthetic crudes. Lubricant prices are assumed to follow this same trend.

The future cost for electricity in the Railbelt is dependent on the method of electrical generation. Because coal price affects the forecast price of electricity in non-Susitna electrical generation, a degree of circularity is implicit in forecasting the electrical price component of coal mining costs. This circularity, though unavoidable, has a minuscule effect on the coal price escalation rate.

4.3.3.4 Royalties

Royalty payments are presently set at 12.5 percent of the realization (selling price). As the labor and energy prices escalate in real terms, the royalty payments will also escalate proportionally (Dames & Moore, 1985, p. 19).

4.3.3.5 Nonescalating Production Costs

(Dames & Moore, 1985, p. 19-23)

The remaining production costs include depreciation of capital investments, parts and supplies, explosives, normal profits, income, and production taxes. All of these costs are assumed to remain constant (in real terms) over the 1985 and 2050 assessment period.

Capital depreciation, parts, and supplies and explosives are assumed to escalation. This is a conservative assumption insofar as the costs for these items are driven in part by energy and labor costs which can be expected to escalate. Income taxes and profits are assumed to remain constant in real terms because normal profits are based on a return on capital investments, which are assumed not to escalate. Because profits will not escalate, income taxes, which are based on profits, will not escalate.

Production taxes include the Alaska License Tax and the federal Black Lung Tax and totaled $0.85 per ton in 1983. They are expected to increase at the general inflation rate over the period of analysis, hence, a zero real escalation rate.

The consequences of this escalation on the mine mouth cost of Nenana coal are shown in Table 4-7. For the analytical base case (the 2 million ton per year mine), the projected mine mouth revenue requirements are $56/ton in the year 2050 (in 1985 dollars). That is equivalent to about $3.70 per million Btu.

The composite real escalation associated with that production cost increase is 1.4 percent/yr.

4.3.3.6 Production Cost Implications

It is important to note that the production cost escalation rate shown above, 1.45%/yr, is lower than the historical rate experienced by Usibelli Coal Mine customers. We are forecasting that the rate of production costs escalation will abate, but it will not go to zero.

Table 4.8 is a presentation of recent escalations in the price of Usibelli coal at the mine month. The GVEA price has escalated at a real rate of 2.0%/yr since 1965, and a 2.1%/yr escalation since 1974. The FMUS price at the mine month has escalated at 2.6%/yr since 1976. The escalation rates after 1974 - 1976 are particularly significant since they occurred after the oil embargo and after the provisions of the Mine Enforcement and Safety Act were fully incorporated into the cost structure of coal mining. This analysis shows that such price escalations will abate in the long term to levels less than those experienced in the recent past. At the same time it demonstrates that there are no data available supporting the cessation of real coal price escalation in the Nenana field.

4.4 NENANA COAL TRANSPORTATION COSTS

(Dames & Moore, 1985, p. 24-37, passim)

The Nenana coal field abuts the Denali National Park, as was shown in Figure 1-1. Nenana field coal from Healy is likely to be transported by rail for Railbelt electrical generation, as the Healy area is in a restrictive Class I airshed due to its proximity to Denali National Park. It would be difficult, if not impossible, to build a coal-fired power plant this close to a National Park. The thermal alternative scenario assumes that two new Nenana coal field-fired generating plants would be located in Nenana, which is the nearest reasonable site to the existing UCM at Healy.

4.4.1 Current Alaska Rail Tariffs for Coal

Table 4-9 shows the 1985 published Alaska Railroad (ARR) rail tariffs for carload shipment of coal from Healy to alternative destinations. UCM owns and operates a loading facility at Healy. This facility has a capacity for up to about five million tons per year. The cost for loading is included in the price quotes for UCM.

According to John Gray, ARR, (personal communication to Marvin Feldman, Dames & Moore, 4/84), unit train operations could reduce rail costs by 15 to 25 percent. However, because the haul distance from Healy to a presumed power plant site in Nenana is so short (about 60 miles), it would be difficult to have a sufficient rate of utilization to justify the high capital investment necessary for unit train equipment. Thus, the $0.39 per MMBtu cost for rail transportation to Nenana might reasonably apply even to large volumes.

4.4.2 Rail Cost Escalation

ARR personnel refused to reveal factor cost data which would have supported an analysis similar to that developed for mining production cost escalation. Instead, rail cost escalation was estimated using two approaches: factor cost escalation based on U.S. average rail costs and U.S. historic rate trends.

U.S. rail cost data disaggregated by individual cost factors were obtained from an American Association of Railroads publication. Using a factor escalation approach and correcting for inflation, an average annual rail cost escalation of 2 percent was obtained, as shown in Table 4-10. To buttress the reliability of the American Association of Railroads' data, a second estimation approach was based on the producer price index for coal transport. The real compound escalation of rail rates computed by this method for the period 1970 to 1981 is 1.8 percent, as shown on Table 4-11. This lower value has been adapted for this analysis.

Rail rates for coal transportation have increased in real terms, as measured by the statistics reported above, for three reasons. First, certain components of the railroads' cost of operation, notably diesel fuel and railroad labor costs, have increased faster than inflation. Second, the railroads specifically have been allowed, in certain cases, to raise rail rates in order to earn a better return on invested capital to allow the railroad to be financially self-sustaining. Third, in many cases, the railroads have had sufficient market power due to lack of competition for shipment of coal over specific routes, allowing them to raise rates and earn a better profit.

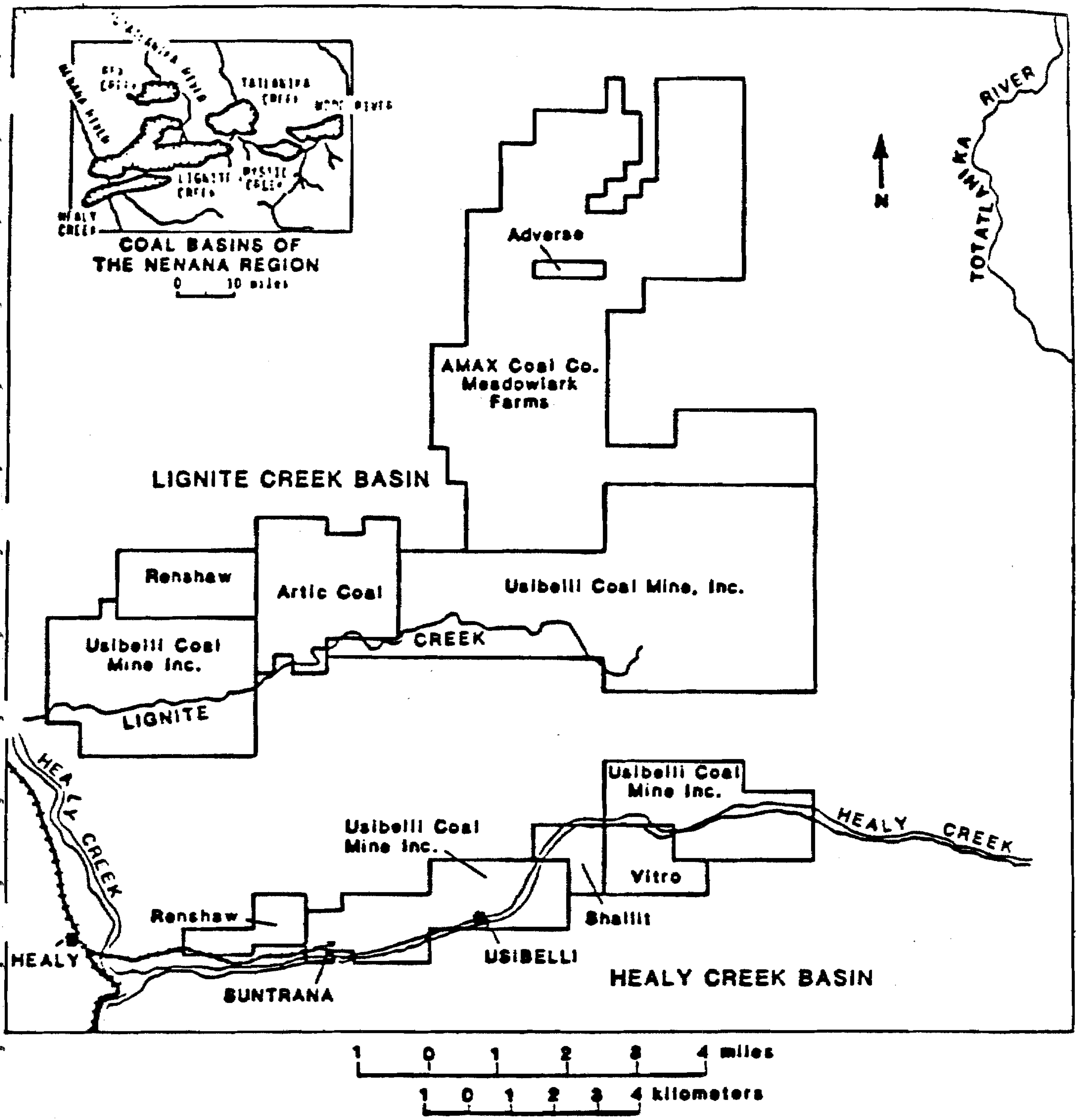
The same factors are relevant in the case of the ARR. Diesel fuel prices are expected to increase in real terms over the study period at a rate of 2.2 percent per year. Furthermore, the ARR has been consistently unprofitable and therefore, presumably must raise rates above their current level to be financially sound. The only competition that the railroad would face for coal movements is trucking, at costs significantly higher than the current rates. There is, therefore, every reason to expect ARR to follow the same course as has been taken by other U.S. railroads. Given this close analogy to the situation of other U.S. railroads, it is reasonable to assume that ARR rates will escalate at the historical rate established by the other U.S. railroads - 1.8 percent.

4.5 NENANA COAL PRICE TREND

Production costing was adopted as the only analytical basis for projecting future prices of Nenana field coal. Based on known geologic information and characteristics of the Usibelli Coal Mine now operating in the Nenana field, mining methods and costs for two alternative mines were estimated. The lower cost of these alternatives, a 2 million ton per year expansion of an existing mine, was chosen as the basis for price projections. Escalation of costs for this mine was then projected considering future increases in labor, fuel, and electricity costs.

Transportation costs from the coal field in Healy, to a possible plant site at the Town of Nenana were determined from data supplied by the Alaska Railroad. Rail rate escalation was estimated from rail cost and rate history in the Lower 48.

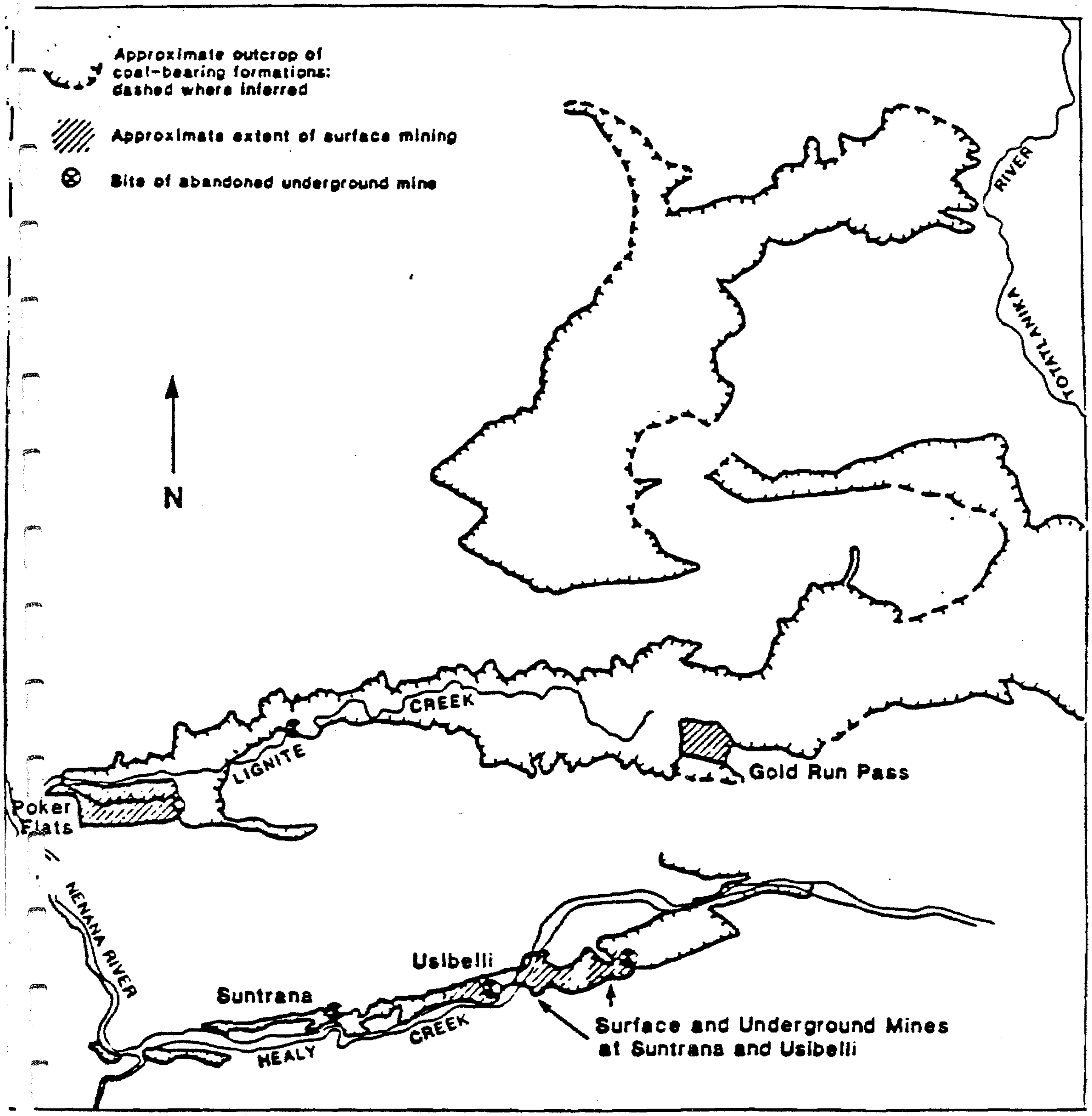
The analytical results of this section include a production cost base price trend of an incremental 2 million tons/yr of Nenana field coal, delivered to a plant in the Town of Nenana. As shown in Table 4-12, the delivered cost of Nenana coal, in the Town of Nenana, would currently be $1.84/million Btu. The real composite escalation rate for this coal is 1.53 percent per year. Adopting this production cost trend provides a conservative price projection for the Nenana field.



After Wahrhaftig, 1970 and Usibelli Coal Mine Inc. file map. 5-23-84.

COAL LEASEHOLDERS IN THE NENANA COALFIELD
Lignite Creek and Healy Creek Basins

FIGURE 4-1



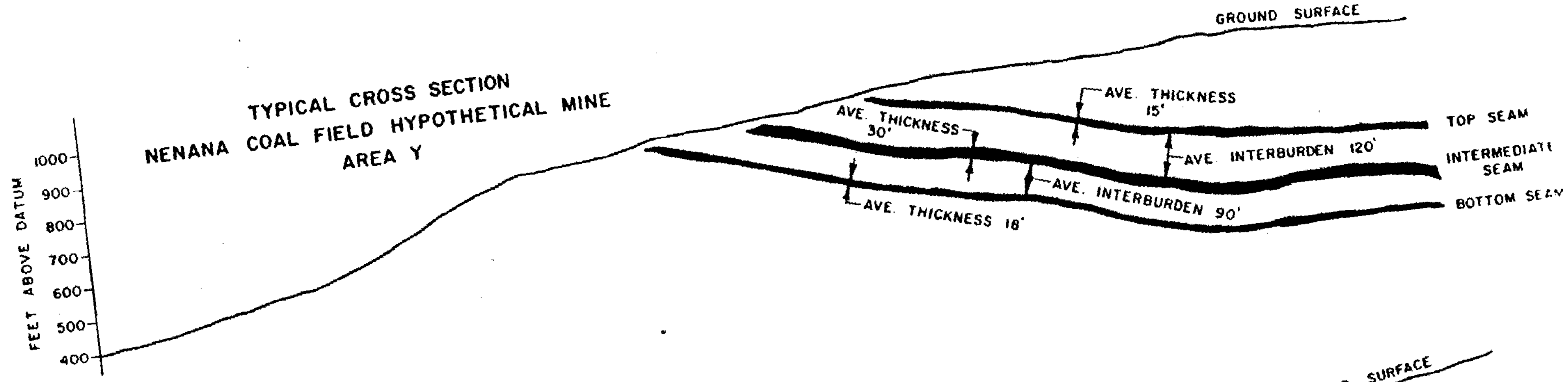
After Wahrhaftig, 1970
Wahrhaftig, 1970, and
Wahrhaftig, et al., 1969.

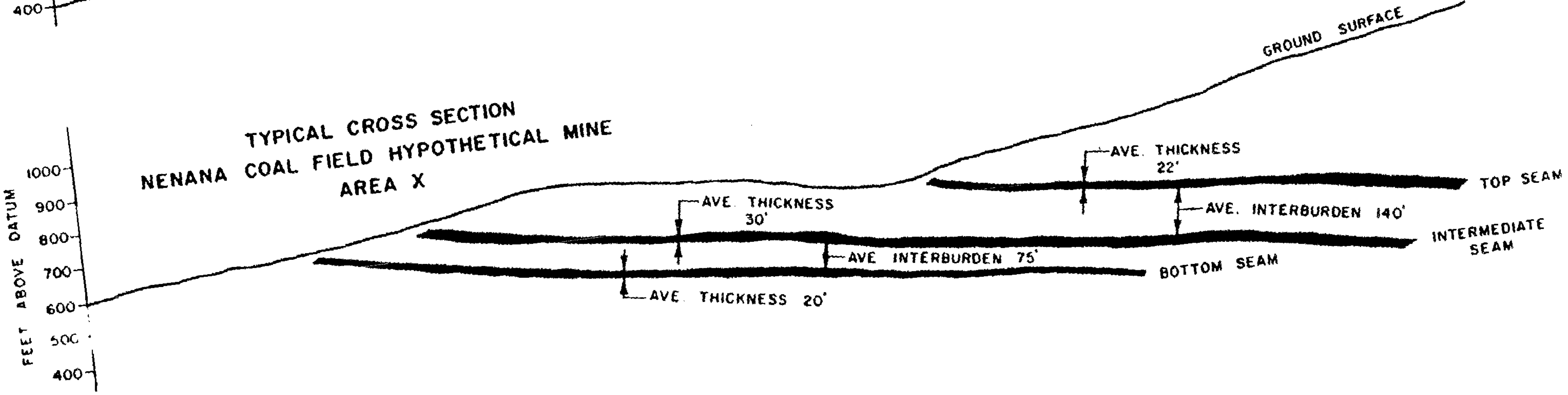
1 0 1 2 3 4 miles

1 0 1 2 3 4 kilometers

AREAL EXTENT OF COAL RESOURCES IN PART OF THE NENANA COALFIELD

FIGURE 4-2

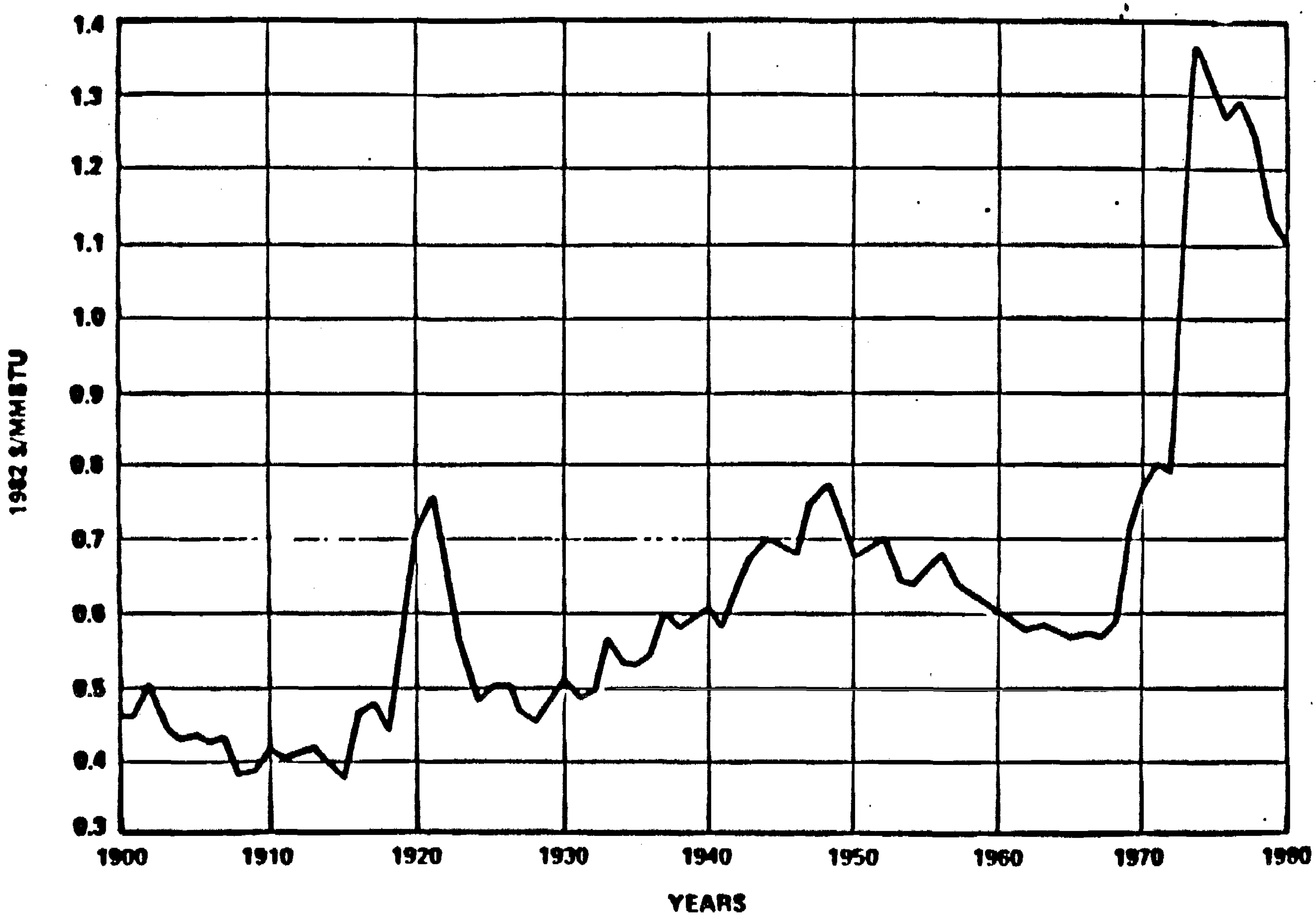




SCALE: 1" = 300'
HORZ = VERT

PAUL WEIR COMPANY
INCORPORATED
CHICAGO, ILLINOIS 60606

FIGURE 4-4

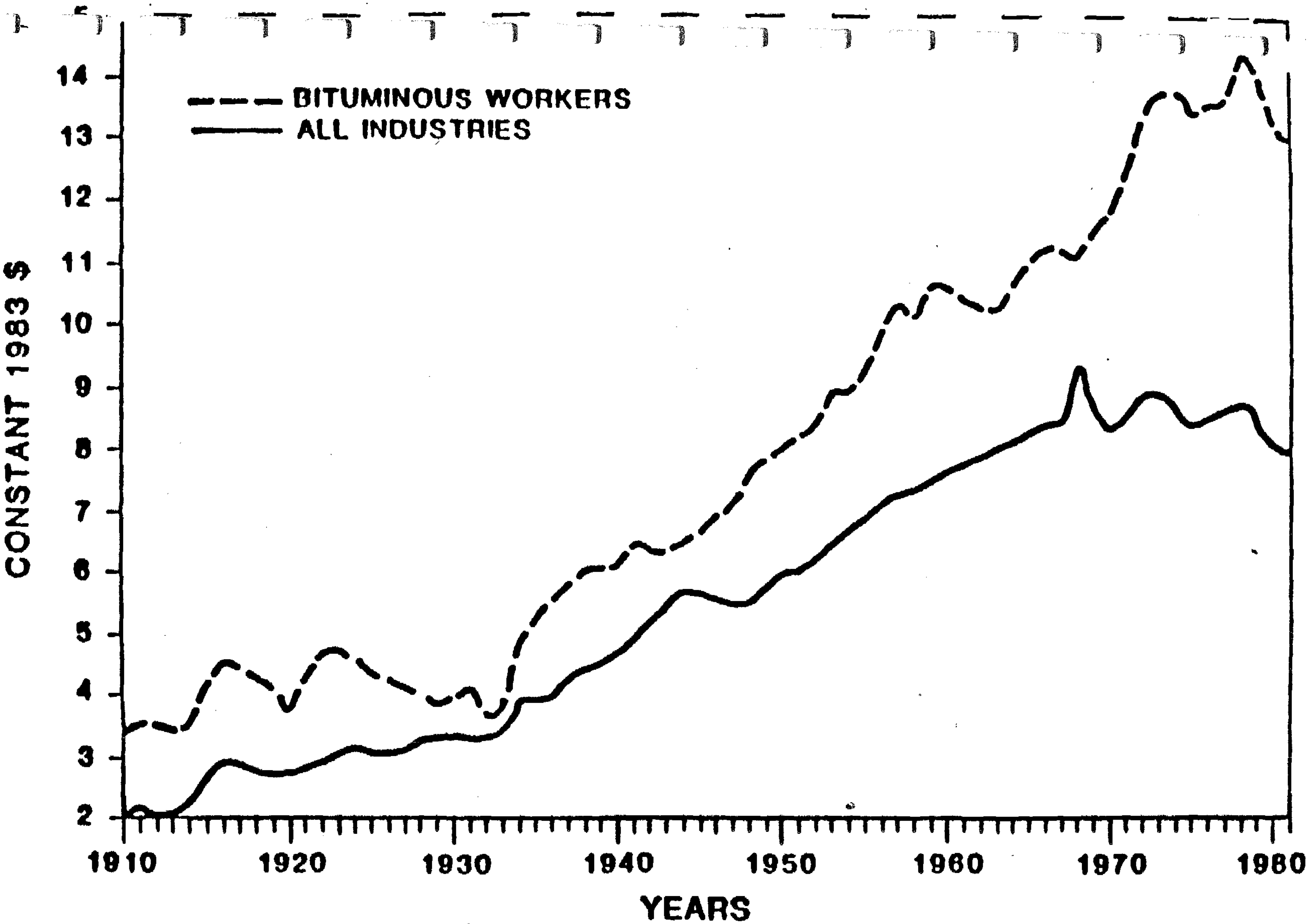


Source: See Table 2-1

SUSITNA HYDROELECTRIC PROJECT

REAL COAL PRICES

FIGURE 4-5



Source: See Table 4-4.

BITUMINOUS VS ALL INDUSTRIES
REAL HOURLY WAGE RATES

WAGE TRENDS 1910 - 1981

TABLE 4-1

RESERVES AND RESOURCE OF THE NENANA FIELD

Reserve/Resource Type	Quantity (tons x 10^6)
Reserve Base	457
Resources	
Measured	862
Indicated	2,700
Inferred	3,400
TOTAL	6,900 1/

1/ Totals do not add due to rounding on measured and inferred. The reserve base is included in the measured resources.

SOURCE: Energy Resources Co. 1980.

TABLE 4-2

ANALYTICAL VALUES USED TO EVALUATE
NENANA FIELD COAL AT FOUR MILLION TON/YR PRODUCTION1/

Parameter (Weight Percent as Received)	Sample 1	2	3	4
Sulfur	0.18	0.13	0.14	0.35
Volatile Matter	32.80	35.71	34.12	32.51
Fixed Carbon	26.54	31.40	29.83	32.55
H_2O	23.61	25.23	25.68	25.29
Ash	17.05	7.66	10.37	9.85
HHV (Btu/lb)	7,022	8,136	7,516	7,779

1/ Represents an increment of 2.0×10^6 tons/yr over UCM existing capacity.

Source: Rao and Wolf 1980.

TABLE 4-4

MAJOR EQUIPMENT USED IN TWO MILLION TON/YR NENANA FIELD MINE

Item1/	Size
Overburden dragline	30 cubic yards
Overburden drills	10-inch diameter
Overburden loaders (front-end loaders)	13 cubic yards
Coal loaders (front-end loaders)	13 cubic yards
Overburden haulers (rear dump)	85 tons
Coal haulers (rear dump)	85 tons
Graders	16-foot blade
Dozers	300 and 400 horsepower
Scrapers	31 cubic yards, twin engine

1/ For number of items and timing of purchase, see Weirco report.

TABLE 4-5

DIRECT WAGES AND SALARIES ASSUMED FOR NENANA FIELD COAL MINERS
(In 1985 Dollars)

Hourly Rated	Rate Per Shift (8 hours)	Salaried	Rate Per Year
Pay Grade 1	$185	Exempt (Average)	$69,100
Pay Grade 2	186	Nonexempt (Average)	57,250
Pay Grade 3	190		
Pay Grade 4	195		
Pay Grade 5	202.50		

TABLE 4-7

NENANA REAL COAL PRODUCTION COST ESCALATION
(Basis: Mine Mouth Coal Cost, 1985 Dollars)

Case	Parameter	1985 Cost ($/ton)	Escalation Rate (Percent)	2050 Cost ($/ton)
2 million ton/yr	Labor	8.26	2.2	36.04
	Fuels and Lube	0.97	2.2	2.25
	Electricity	0.76	1.3	1.76
	Royalty	2.76	1.3 1/	7.05
	Other Operating Costs, Capital, and Taxes	9.33	0.0	9.33
	TOTAL	22.08	1.45 1/	56.43

SOURCE: Dames & Moore August 1985, Table 2-5.
1/ Derived.

TABLE 4-8

PRODUCTION COST ESCALATION FOR NENANA FIELD COAL

Parameter	Usibelli Coal Golden Valley Electric Assn.	Contract Fairbanks Municipal Utility System
Base (Contract) Year	1974	1976
Base Coal Price	$0.47/MMBtu	$0.72/MMBtu1/
Current Coal Price2/	$1.30/MMBtu	$1.56/MMBtu
Escalation Period	11.25 yrs3/	8.5 yrs4/
Escalation Rate	9.46$/yr	9.52%/yr
Inflation Rate During Escalation Period	7.2%/yr	6.7%/yr
Real Rate of Coal Price Escalation	2.2%/yr5/	2.6%/yr

1/ $12.61/ton x ton/17.4 MMBtu
2/ First quarter, 1985 as reported by utilities
3/ Contract began December 1, 1973
4/ Contract began July 1, 1976
5/ If the GVEA rate is calculated over a 20 year period, the nominal escalation rate for coal is 8.0%/yr and the inflation rate is 5.9%. The real escalation rate is 2.0%/yr.

Sources: Utility current coal prices; Usibelli contracts with GVEA and FMUS. Statistical Abstract (1984) and U.S. Department of Commerce.

TABLE 4-9

ALASKA RAILROAD TARIFFS FOR COAL SHIPMENTS ($ 1985)1/

Healy (Suntrana) to:	Mileage	$/Ton2/	$/MMBtu3/
Nenana	58	5.92	0.39
Willow	177	9.54	0.63
Matanuska	212	10.84	0.71
Anchorage	248	12.15	0.80
Seward	363	12.83	0.84

1/ Inflated from 1984 dollars using a value of 1.087.
2/ Personal communication with Dennis Smith, Alaska Railroad, 4/85.
3/ Cost per million Btu assuming 7,600 Btu per pound coal.

TABLE 4-10

U.S. AVERAGE RAILROAD COST AND ESCALATION RATES

Factor	Proportion of Total Costs (Percent) 1/	Average Annual Escalation Rate (Percent) 2/	Factor Weighted Escalation (Percent)
Labor	47.2	11.1	5.2
Fuel	12.2	10.5	1.3
Materials and Supplies	12.2	4.7	0.6
Equipment Rents	6.7	13.2	0.9
Purchased Services	6.2	10.0	0.6
Depreciation	4.3	4.2	0.2
Interest	3.8	4.8	0.2
Taxes (other than income and payroll)	1.4	0.6	0.055
All Other Operating Expenses	5.9	6.5	0.455
Total Annual Escalation			9.4
Implicit Price Deflator 3/			7.3
Real Rail Cost Escalation Rate (%) 4/			2.0

1/ Personal communication, Carol Lutz, AAR, 5/84.

2/ AAR Railroad Cost Recovery Index, 3/84 (1979 - 1983 U.S. average).

3/ DRI Review of U.S. Economy, 9/83 (1979 - 1983 U.S. GNP deflator).

4/ Real escalation is calculated as follows:

$$\frac{1.094}{1.073} = (1.0196-1) \times 100 = 1.96\%$$

There being no basis for believing that the ARR has characteristics different from the average U.S. railroad, these data support a positive rail escalation rate.

TABLE 4-11

RAIL PRICE ESCALATION

	1970	1981	Average Annual Percent Change
Producer Price Index (PPI)			
Rail Freight, Coal Transport 1/	108.6	305.7	11.25
Producer Price Index			
All Commodities 2/	110.4	293.4	9.29
Real Escalation Rate			
Based on PPI = 1.8%			

1/ Page 628, Table 1093.
2/ Page 456, Table 751.

SOURCE: U.S. Statistical Abstracts 1982 - 1983.

TABLE 4-12

THE PROJECTED PRODUCTION BASED COST OF NENANA
FIELD COAL DELIVERED TO NENANA
(BASIS: 1985 $/Million Btu)

Year	Cost Component: Mine Mouth Coal Production	Cost Component: Rail Transportation	Total
1985	1.45	0.39	1.84
1990	1.56	0.43	1.99
1995	1.67	0.47	2.14
2000	1.80	0.51	2.31
2010	2.08	0.61	2.69
2020	2.40	0.73	3.13
2030	2.77	0.87	3.64
2040	3.20	1.04	4.24
2050	3.70	1.24	4.94

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Chapter 4

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5.0 BELUGA COAL FIELD SUPPLY AND PRICE ANALYSIS

The Beluga coal field contains a fuel of similar quality to that available in the Nenana coal field. Economically, however, the products of these two deposits differ significantly. Nenana coal is situated in a modestly populated area of Alaska, and in an area with some infrastructural development (highway, railroad). Beluga coal, on the other hand, is a totally undeveloped near-tidewater area where highways and railroad spurs are absent and only a few small settlements exist. Nenana coal is accessible to the Alaska domestic market. Beluga coal can be easily gotten to export markets by moving the coal to a tidewater facility. The proposed Diamond Alaska coal project is only 12 miles inland. Because of transportation limitations, Beluga coal could only move into the local marketplace through mine mouth power plants tied into the Railbelt electric grid. The markets for Nenana and Beluga coals will tend to remain distinct and separate. Therefore we consider Beluga coal, its markets and development as a separate issue.

5.1 THE BELUGA COAL FIELD

(From Weirco, 1985)

The Beluga field is located in the Susitna Coal Field in south central Alaska, approximately 50 miles west of Anchorage. The coal resources of the Susitna field are comprised of the Yenta area in the north and the Beluga area in the south, as shown in Figure 5-1. Both areas contain multiple seams of low sulfur, lignite-to-subbituminous coal. Coal thicknesses run from less than 6 feet to 50 feet. Overburden and innerburden lithologies range from massive sandstone and conglomerate to poorly consolidated shales, siltstones, and claystones. The strata are generally gently-to-moderately dipping, although some folding and faulting have occurred, resulting in locally steep dips in some areas. Bedrock is typically overlain by glacial till and muskeg. Topographic relief is moderately rolling, with some areas of steeply incised streams and rivers. Vegetation ranges from grasses and scrub brush in the upper elevations to dense stands of evergreens at lower elevations. The Schaff, 1980 listed the indicated and inferred resources for the Susitna field at 2.7 to 10.2 billion tons. Hypothetical resources are listed at 27 billion tons.

The quality of Beluga coal is comparable to that of Nenana coal. Weirco (1985) estimates that the average as-received calorific value at 7,500 Btu/lb. The coal deposit projected to be mined by Diamond Alaska Coal Co. may be slightly higher in quality. Table 5-1 contains one set of Diamond Alaska Coal Company average values. Table 5-2 contains a second set based on the power plant proposed by Gilbert Commonwealth. The range of expected coal quality in the field as a whole is 7,200-7,800 Btu/lb.

5.2 DEMAND FOR AND SUPPLY OF BELUGA FIELD COAL

There has never been any coal produced in the Beluga area. Demand for Beluga coal may develop in the near future. This demand may come either from domestic (Alaska) markets or from export markets. Diamond Alaska Coal Co. is actively marketing coal from its prospective mine to potential customers in the Pacific Rim area.

5.2.1 Domestic Demand for Beluga Coal

The thermal alternative to Susitna OGP model projects that three 200 MW coal-fired mine mouth power plants could be built in the Beluga area after the turn of the century. The domestic market for Beluga coal is more a long-term than a near-term prospect.

5.2.2 Export Demand for Beluga Coal

The expected dominant market for Beluga coal is the export market. This has been forecast by numerous analysts including Battelle Pacific Northwest Laboratory (Swift, Hoskins, and Scott). Diamond Alaska Coal Company also has forecast a large export market for Beluga coal. This forecast is shown in Table 5-3. The total short- and long-term Pacific Rim market was discussed in Section 3.0.

It is useful to examine this vast market in terms of the unconstrained potential demand for Alaska coal, particularly Beluga coal. Unconstrained potential demand measures the exports that could possibly be made by Alaska coal producers if no limits exist on the number and size of mines opened, the number of mines available, the capacity of the overland transport system, the capacity of the port, and the environmental (including socioeconomic and sociocultural) acceptability of such growth. Unconstrained potential demand measures what the market could absorb, limited only by considerations of Alaska's market penetration and market share.

Dames & Moore, 1985b has prepared estimates of unconstrained Alaska coal exports. These are based on coal import projections described in Section 3.0. Alaska exports were then determined considering the cost-competitiveness of Alaska coal compared to sources in other countries, such as Australia. The projections also considered limitations on market penetration due to the very low calorific value of Alaska coal compared to that available from competing sources. Many consumers will be unwilling to make the investments necessary to accommodate this lower quality product.

The Dames & Moore 1985b (Table 3-17) estimates, which indicate that Alaska could garner 19% of the Pacific Rim steam coal market by the year 2030, are shown in Table 5-4. It is assumed that nearly all of these exports will come from mines in the Beluga field. This is due to the proximity of the coal to tidewater, compared to other coal fields, which would need transported by rail.

5.2.3 Beluga Coal Supply

Currently no active mine exists in the Beluga coal field.. The Beluga Field totally lacks infrastructure. Several developers have plans to produce in that region, however. These developers include the Diamond Alaska Coal Company, and Placer Amex Company. Involved in their plans are such infrastructural requirements as the construction of a town, transportation facilities to move the coal to tidewater, roads, and other related systems. These auxiliary systems are necessary if one or more mines are to be made operational. Other leaseholders in the Beluga Field include Mobil Oil Company and Amex Coal Company as shown in Figure 5-2.

Diamond Alaska Coal Company holds leases on 20 thousand acres of land (subleasing from the Hunt-Bass-Wilson Group), with 1 billion tons of subbituminous resources. Engineering has been performed for a 10-12 million ton/yr mine designed to serve export markets on the Pacific Rim; and the engineering has involved a mine, a 12-mile overland conveyor to Granite Point, shiploading facilities at Granite Point, town facilities, and power generation facilities.

The mine itself involves two draglines plus power shovels and Commonwealth, 1985). The Beluga Coal Company of Placer-Amex plans involves a 5 million ton/yr mine in the Beluga Field, also serving the export market. This mine could be doubled in size if demand warrants.

The leases supporting these proposed mines are shown in Figure 5-3. It is significant to note their proximity to tidewater. It is also significant to note that these developments are substantial. Diamond Alaska projects the expenditure of some $500 million as a capital investment. It forecasts the use of about 20,000 acres as is shown in Table 5-5 It is obvious, then, that the Beluga field could be developed to meet large demand.

5.2.4 Supply Constraints

Meeting large demand, and meeting the total potential export demand, encompass two different issues, however. Potential unconstrained demand for Alaska coal has been estimated by Dames & Moore at over 200 million tons/yr by 2040 as shown on Table 5-4. On this basis it is essential to examine whether Alaska could supply such a demand. Dames & Moore examined this issue and identified the following as probable maximum supply levels:

Year	Maximum Production
	25-30 million tons/year
2010	25-30 million tons/year
2030	50 million tons/year
2050	75-100 million tons/year

This supply limitation analysis was based upon examining the consequence of coal mining developments building to 300 million tons/yr. It is summarized below.

The potential problems arising from intensive development of the Beluga coal field are likely to be quite unique. The possible scale and pace of development, as measured by the direct mine employment, would be exceptional even when compared with rapidly growing mining communities such as Prudhoe Bay, Gillette, Wyoming and Grants, New Mexico. A possible analogy would be the old gold and silver towns, such as Silver City, of the old West.

The Beluga area would be considered a relatively desirable one in which to live, with an acceptable climate, abundant wildlife and attractive setting. This is in contrast, for example, to development on the North Slope. The total population today of the area along the inlet around Tyonek and Beluga is probably less than 500. Most of the area is completely roadless and undisturbed. No year-round road connections to Anchorage exist, only a seldom used winter ice route. Land ownership divisions between CIRI, State, and Tyonek control create multifold possibilities for conflict. The history, legal status, and attitudes of the Tyonek people create a need for extraordinary sensitivity toward their desire to remain as they are.

The specific analysis includes Table 5-6, which indicates the magnitude of the manpower, population, land disturbance, transportation network, and environmental effects which the unconstrained coal exports would entail. The consequence of this impact is a series of socioeconomic and sociocultural constraints limiting coal production.

The most significant constraint is the desire of the Tyonek people to preserve their traditional isolation and free access to the land, fish, and game of the region. Given the very small population in Tyonek (about 270 in 1979), a nearby white population of a few thousand would produce a perceived intolerable degree of disturbance. Even with extraordinary measures to preserve the isolation of the Tyonek village and the immediate area, a mining community of several thousands would fundamentally change the character of the region.

Aside from the Tyoneks, the next most significant constraint is likely to be the desire of CIRI and the State to maintain the pace of development at a level which does not produce the many undesirable effects of rapid boom town growth such as inadequate services, strained water supply and sewerage treatment facilities, transportation bottlenecks, poor housing, and similar problems. Given that development would start from a zero base, controlled development would be a challenge.

The other factors examined, availability of reserves, coal transportation and port and shipping, and air quality, may present serious challenges but may not individually pose effective constraints on development, even at production levels in excess of 200 million tons per year (assuming that the available reserve estimates are at all indicative of the real reserves). The magnitude of such challenges, while not insurmountable, is substantial. In shipping alone, it means being able to handle an average of 13 ships per day by the Year 2050, as is shown in Table 5-7.

Considering the total disruption of the environment--with as much as 10% of the regional area disturbed by mining, with several ships a day loading in Cook Inlet, with thousands of people living in the area, with powerlines, roads, conveyors, rail lines, and pipelines crossing the region, and intensive mining equipment use--very large Beluga coal development is difficult to assume. The State and CIRI must be willing to make a decision to see the region substantially transformed from a wilderness to a mining center. Beluga would become not just an isolated mine and camp, but a developed mining region. Coal mining activity is necessarily very land-intensive, both for mining and transportation corridors, and may well create at least difficult-to-resolve environmental problems. What maximum production levels are implied by these constraints? If the preservation of the Tyonek way of life is a constraint, then production of much more than 25 million tons per year would be intolerable. If the constraint is effective management of the pace of development, then a reasonable production limit for the year 2010 would be 25-30 MMT/Y rising to 50 MMT/Y in 2030 and 75 MMT/Y in 2050. If the constraint is environmental, perhaps 100 million tons per year would be the maximum tolerable production.

5.3 BELUGA COAL PRICE FORECASTS

Ultimately, the issues of demand and supply converge into a price analysis. Projecting future prices for Beluga coal has become a somewhat controversial issue. Diamond Shamrock, and the Diamond Alaska Coal Company have provided a variety of coal price estimates, some of which are reproduced below:

From the Cook Inlet Story (1983):

> So abundant and so accessible will Chuitna coal be that we are projecting a selling price that could be as low as $2 per million Btu. That is about one-third what a Pacific Rim utility would pay to generate an equivalent amount of energy by oil or gas.

From the DSCSC February 1983 Briefing Paper:

	Alaska	
	$/Ton	$/Million Btu
FOB Port	19.00-28.00	1.20-1.70

From the Gilbert Commonwealth (1985) Report:

> The Diamond Alaska Coal Company estimates that the cost of coal for the Beluga Power Plant may range from $14 to $18 per ton at the port.

Similarly, Cole McFarland, Vice President of Placer U.S. testified at a public hearing in Anchorage, commenting on the economic and financial update:

> Beluga coal can be delivered to a "minemouth" (within 12 miles from proposed mine sites) generating plant for less than $1.50 million Btu in 1984 dollars for a mine production rate of approximately 1,000,000 tons per year. The heat value of the coal will range from 7,500 to 7,800 Btu per pound.

The Diamond Alaska Coal Company estimates, then, have varied by a factor of 2 within the past two years. Further, the Placer Amex number is in the middle of the Diamond Alaska Coal Company range of published values.

In order to deal with this uncertainty, the Alaska Power Authority commissioned studies both by Dames & Moore and by Paul Weir Company (Weirco). These studies were designed to identified an appropriate price trend not only for the Diamond Alaska mine, but for a "representative" mine in the Beluga field.

5.3.1 Theoretical Basis of Supply Analysis

(From Dames & Moore, 1985, Section 3.3.1)

The analysis examines competing supplies that are available, to satisfy the coal import requirements of Pacific Rim consumers. The full cost of production (i.e., the equivalent of the mine levelized revenue requirement) of the highest cost (i.e., marginal) mine needed to supply the given demand level was determined at ten-year intervals as the basis for the Pacific Rim market price trend. Logically, the lowest cost mines are developed first. As more and more coal would be imported, and reserves would be gradually depleted, new mines must be opened.

Each increment of production is higher in cost. One can therefore compare coal production versus cost, and a rising curve results. The market price trend, determined by comparing the demand level in each period to these representations of coal supply, rises as true costs of mining more costly resources rise.

Ideally, the coal supply representation would be developed in a fashion that economists call a formal "supply curve." As discussed in Dames & Moore's November 1984 report, data limitations force the adoption of a more limited but similar representation of coal production potential: a "solution curve."1/ The analysis must be considered an engineering cost analysis and the result must be classified as a solution curve rather than a supply curve.

The estimated coal solution curve consists of an arrangement of the potentially available coal supplies in increasing order of delivered cost to the

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1/ A solution curve shows the price quantity relationships given the quantity of coal produced with quantity an exogenous variable. In contrast, a supply curve shows the price quantity relationship where quantity of coal produced is endogenous to the calculation of price. For example, given a production function that relates quantity produced as a function of input prices, we would calculate price and quantity as functions of varying levels of inputs and input prices. In a true supply curve optimum levels of inputs are determined from profit (or quantity) maximization, whereas in a solution curve the optimum combination of inputs is assumed in the engineering cost estimates.

consumer. Because the demand projection indicates a fairly steady growth in consumption, coal producers will almost constantly be building new mines (except perhaps during recessionary periods). Therefore, the market price must be at least at a level sufficient to attract capital for opening new mines.

Coal producers opening new mines are assumed to earn only the market rate of return on investment. No additional exploitation of economic rent by the producers is assumed. This provides a base price trend projection keyed to the marginal cost of the last increment of production, the incremental mine. The cost of production used to develop the solution curves includes market return on capital as well as operating costs, taxes, and royalties. Taxes and royalties are assumed to remain constant at existing levels. The solution curves discussed below represent the total reserves available for mining plotted against cost of production. No annual production capacity constraints are assumed because the analysis focuses on the period beginning in the mid-1990s. Since mine planning and construction times are usually less than 10 years even for the most complex projects, production capacity should always be sufficient. This is of course subject to the assumption that producers are able to foresee demand.

5.3.2 Development of Solution Curves

(From Dames & Moore, 1985, Section 3.4)

Solution curves were estimated for the years 2000, 2010, 2020, 2030, and 2040. These curves are built up from the components of coal supply, that is, the various locations and types of mines, in Australia, Canada, Colorado, and Wyoming. China's coal is not included in the solution curve but exports from China are allocated a share in meeting the total coal demand. Alaska coal is not included initially in the solution curves because they are used initially to determine the Pacific market price in the absence of Alaska coal exports. The methodology by which Alaska exports are reflected in the market price is discussed later in Section 5.3.3.3. Values for the year 2050 were developed by calculating a real escalation rate of 2.1%/yr and applying that rate to the 2040 value. For each supply region recoverable coal reserves were determined and categorized by mining method, and the cost of mining estimated, given current the producer enough to get him to open a mine.[1/] Each additional increment of demand must be matched with a steadily more expensive increment of supply. Prices therefore can be determined by finding the cost of supplying a given level of demand (consumption). The solution curves relate coal price to coal reserves "used." The reserves used include those mined between today and the forecast year, plus reserves dedicated to future production at that time. This is true because mines are not opened for a single year's production of coal, but rather for a productive life of 10 to 30 years (even longer occasionally). Therefore, dedicated or committed reserves are the sum of depletion plus reserves dedicated to future production. Depletion is the reduction in available reserves to account for past production. Reserves dedicated to future production are estimated in this study to be 20 times current production levels. Having established a solution curve that relates production levels and costs, the next step is to compare these solution curves with demand to derive a price forecast. The solution curve for the Year 2000 is shown in Figure 5-4.

1/ Add footnote.

5.3.3.1 Export Market Demand

(From Dames & Moore, 1985, Section 3.5.1)

The balance of supply and demand, determined by the cost of opening the last new mine to satisfy the increasing demand level, is related to the solution curves developed here by comparing the demand, represented by the reserve commitments, with the supply, which represents the cumulative reserves developed.

The figure that must be used for coal demand is not simply the current consumption level in a given year. It must also reflect depletion and reserve commitments. To determine future reserve commitments, coal production (which equals consumption) is multiplied by 20. An allowance also must be made for the participation of China in the market. We are allocating a 15 percent share of the market to China "off the top" before comparing the projected supply and demand. Each step of this calculation is shown in Table 5-8.

Table 5-8 shows the total imports by year for the Pacific coal importers. These rise from 167 million MTCE in 2000 to 662 million MTCE in 2040. On the second line of the table, the cumulative imports are shown, the sum total production over time. These rise from 1,285 million MTCE in 2000 (the cumulative total from 1990 to 2000) to 18,000 in 2040.

Next, the Chinese 15 percent market share is accounted for by reducing the cumulative production by 15 percent (calculated by multiplying the cumulative imports by 0.85). For example, the cumulative imports in 2000 are reduced from 1,285 million MTCE to 1,092 million. Reserve commitments are shown on the next line of the table. This line is the sum of the cumulative imports, less the Chinese share, plus 20 times the production in that year, also less 15 percent for the Chinese share. For example, in 2000 the reserve commitment of 3,913 million MTCE is the sum of the cumulative imports less the Chinese share, or 1,092 million MTCE, plus 20 times 167 million MTCE of imports in 2000, times 0.85.

5.3.3.2 Supply/Demand Comparison and Prices Without Alaska Exports

(From Dames & Moore, 1985, Section 3.5.2)

The reserve commitments shown in Table 5-8 are compared to the solution curves for each year to determine what price is needed to produce enough coal to satisfy the demand, assuming, initially, that all coal exclusively from the non-Alaska sources is incorporated in the solution curves. The price determination is made simply by reading across the horizontal axis of the solution curves to the appropriate tonnages of reserves and reading the price for that point on the supply curve.[1/] Figures 5-5 and 5-6 show the supply/demand comparison for the with and without Alaska suppliers for 2000-2040. In each figure the demand, with and without export of Alaska coal, is shown as a vertical line.[1/] The price is shown where a horizontal line connects the intersection of the demand estimate and the solution curve. Table 5-9 shows the 2000 demand for each reserves, reserve commitments, to be 3.9 billion MTCE. Figure 5-5 indicates that a price of about $76/MTCE, CIF Japan, will elicit supplies to clear the market.

The effect of exports of Alaska coal is, of course, to increase the supply available to Pacific market consumers. Hence, to calculate the effect on prices, the solution curve should be shifted to the right, increasing the available supply at a given price. For ease of mechanics of presentation, the demand is shown as shifted to the left by the amount of Alaska exports. This allows both states of the market (with and without Alaska exports) to be shown on a single graph.

Table 5-10 shows estimated Pacific market prices by year without Alaska exports. The price estimated for 2000 is $76 per MTCE, or $2.73 per million Btu (calculated by dividing the per MTCE price by the 27.8 million Btu in an MTCE). The prices rise to $93 per MTCE in 2010 and $115 per MTCE in 2040. The supply

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1/ Alaska exports can be added to supplies or subtracted from demand to show how Alaska production changes the market price determination. Implicitly, it is assumed that the demand is completely inelastic; that is, that coal prices do not influence the consumption of coal.

breakwater construction since few sheltered sites are available. Alternatively, more costly coal from Australia could fill the gap. ·

The least costly of these alternatives is the $10 per MTCE (in 2030) additional ocean freight. In 2030 a supply mix including only 75 million MTCE of Wyoming coal (versus 237 MTCE as shown in Table 5-11) would require an additional 3 billion MTCE of reserve commitments of Australian coal, raising the market price from $119 per MTCE, to reflect the higher cost of Australia coal.

Therefore it is most likely that the supply cost of Wyoming coal will be about $10 per MTCE above the price indicated by the "unconstrained" solution curve, as is shown in Table 5-10.

5.3.3.3 Market Penetration of Alaska Coal

(From Dames & Moore 1985, Section 3.5.3)

Alaska coal can be produced at a cost that is very competitive with the prices projected in Table 5-10, which do not reflect exports from Alaska. To determine just how economically competitive exports for Alaska might be, the Pacific market price FOB a mine in Alaska must be compared with production costs in Alaska. In the next section, the projected production costs of coal from the Beluga coal field are discussed.

The transportation costs from the mine to Japan included trucking costs to a port on Cook Inlet, costs for port ownership, and operation and ocean freight costs from Alaska to Japan. These costs are shown on the second and third lines of Table 5-12. A detailed discussion of the derivation of the port and inland transportation costs is presented in Appendix E of the Dames & Moore November 1984 report. The port and inland transportation costs rise over time due to the increase in diesel fuel costs for truck hauling from the mine to the port. As discussed earlier, ocean freight costs also rise (at 0.8 percent per year) due to increasing fuel costs. In 2000 the ocean freight plus inland transportation and port costs are $23 per MTCE; they rise of $30 per MTCE in 2040.

The price of coal from competing sources delivered to Japan less the transportation costs from the mine in Alaska to Japan equals the maximum price at which the Alaska coal producer is competitive. This price is shown on the line in Table 5-12 labeled, "Net FOB Mine." The net FOB mine price in 2000 is $53 per MTCE, or $1.78 per million Btu, quality adjusted.

In order to make a fair comparison of Alaska coal with other competing supplies, it is necessary to account for the difference in quality between Alaska coal and the coal from the competing producers. Coals from Australia, Canada, and Colorado are of considerably higher calorific value than Alaska coal. To compensate for this and other quality differences we deduct 5 percent from the apparent calorific value of Beluga coal. The representative Btu content of coal from the Beluga field used in this study is 7,500 Btu per pound. This must be reduced to 7,125 Btu per pound to adjust for the quality disadvantage of Beluga coal compared to competing suppliers. In addition to this 5 percent "discount" a further reduction in the FOB mine price of $.43 per ton must be made to further account for the quality differential. Therefore the value to the consumer of Alaska coal, must be reduced by 5 percent and $.74 per MTCE ($.03 per million Btu).

The FOB mine price adjusted for quality differences and expressed in dollars per million Btu is shown on the bottom of Table 5-12. This price begins at $1.78 per million Btu in 2000 and rises to $3.22 per million Btu in 2040. In 2000, the net FOB mine price is $1.78 per million Btu is substantially higher than the production cost estimated in Section 5.3.3.4. This indicates that, at least as early as 2000, Alaska coal will be competitive in the market. By 2010 the cost advantage of Alaska coal increases significantly. The FOB mine price 2010 is $2.16 per million Btu.

Having established that Alaska coal will be very cost-competitive in the Pacific market, we can now estimate the probable exports of Alaska coal and re-estimate the market price, taking account of the reduction in needs for coal from competing sources.

Because the Beluga coal is much lower in quality than coal from the principal competing suppliers (until 2030, when Wyoming coal begins to move into the market), boilers and other plant equipment must be specially adapted to burn this coal. Shifting between Alaska coal and coal from other sources will be difficult for the user. Therefore only the large coal fired boilers used in the electric power sector are a good market for Alaska coal. We therefore believe that the market penetration of Beluga coal will be confined to the electric power sector. Consumers also seek to maintain a diversity of coal sources, both to preserve security of supply and to maximize bargaining leverage.

Based on an examination of other cases of constrained (e.g., by security or quality considerations) market penetration, such as that of South Africa into the European steam coal market and Australia into the Pacific metallurgical coal market, we estimate that Alaska coal producers can capture no more than 25 percent of the Pacific electric power coal import market. This market penetration estimate, combined with our assurance of the low production cost of Alaska producers, is the basis for the projected Alaska coal exports shown in Table 5-13.

The exports projected for Alaska in 2000 are 16 million MTCE, rising to 40 million MTCE in 2010, 67 million MTCE in 2020, and 116 million MTCE in 2040. The market share of Alaska producers in relationship to the total imports from all sources is 10 percent in 2000, rises to 17 percent in 2020, and reaches 20 percent in 2040. Considering the cost advantage of Alaska coal producers this market penetration is modest. It is sufficient, however, to affect the market price of coal in the Pacific.

Table 5-14 shows the downward revision of reserve commitments, compared to those in Table 5-8 to account for the exports of Alaska coal. These revised reserve commitment figures are then used, by comparison with the supply curves as before, to determine a new set of Pacific market prices and Alaska netback prices. The revised reserve commitment estimates are calculated simply by multiplying the original reserve commitment figure by one minus the Alaska share of the total market. Therefore, they are from 10 to 18 percent lower than the original reserve commitment figures.

The revised reserve commitment figures are, of course, lower and result in lower prices than the demand excluding Alaska coal. Since the solution curve is fairly flat, this reduction in demand does not result in a significant change in the prices. The revised netback prices, starting at \$1.78 per million Btu (including adjustment for lower quality of Alaska coal), is compared to \$1.67

for the original price estimate (see Table 5-12), a difference of only 6.2 percent.

The largest effect on the Pacific market price occurs in 2010, when the price drops by $0.11 per million Btu, or 5.1 percent. In 2030 and 2040 the price is not affected at all. This is because the marginal supply at this time is the large amount of production available from the Powder River Basin in Wyoming, which remains the marginal supply despite the introduction of Alaska coal into the market.

As was done for the market balance without Alaska exports, the composition of the solution curve can also be used to derive an overall supply/demand balance for the Pacific market, in which Alaska coal exports may be seen in perspective. As shown in Table 5-13, the Chinese share is 15 percent. The Alaska share (based on 25 percent of imports for electric power generation) increases from 10 percent to 19 percent from 2000 to 2030. Exports of the other supplier, based on the proportion of reserves they contribute to the overall solution curve, are led by Australia with 48 percent in 2000, dropping to 13 percent of the market in 2040. Wyoming coal enters the market in 2030. Canadian producers reach maximum capacity in 2020, and Colorado producers reach maximum output in 2030.

Overall, this supply-demand analysis shows that there is plenty of "room" in the market for Alaska coal. It also shows that, due to overlap of supply costs of various producers, the conclusions as to prices are likely to be insensitive to any small errors in the supply cost of any source. One might ask whether the large levels of exports projected for Alaska coal could be attained. The known resources in the Beluga field are large even in relationship to these export levels. The reserve commitment of Alaska coal to sustain the projected export levels is summarized in Table 5-15. The calculation of reserve commitments of Alaska coal is similar to that described earlier, that is, the sum of depletion (past production) plus 20 times the export level in each year.

5.3.3.4 Production Cost Estimation

While the market value of the Alaskan coal, netted back to Alaska, represents the most probable price of coal for the planning period 1985-2051, the Alaska Power Authority and its subconsultants also estimated a floor price - the full cost of production as escalated over the planning period. This estimation was performed in the same manner as the pricing studies for the Nenana coal field. Weirco, 1985, estimated the levelized cost of coal produced in the Beluga field, both in an 8 million ton/yr mine and a 12 million ton/yr mine. Again the estimates were made in 1985 dollars. They were made by postulating a coal deposit, developing a mining plan, and then developing a cost estimate, as described in more detail in Section 4.3.2. Additional studies were made at smaller mines, although there are considered less likely economic developments.

Deposit Characteristics

(From Weirco, 1985)

The hypothetical Beluga deposit selected for this study contains three minable seams of subbituminous coal designated: L, M, and U (for Lower, Middle, and Upper). The seams are separated and/or overlain by poorly consolidated shales, sandstones, and siltstones. The surface material consists of varying thicknesses (0 to 40 feet) of glacial till, which is overlain by muskeg. The coal seams dip at 3 to 10 degrees, with an average of approximately 5 degrees (8 percent). The Lower Seam thickness ranges from 23 to 38 feet, averaging 26 feet. This seam contains partings of variable thickness which must be removed to preserve the quality of the product. The Middle Seam averages 28 feet in thickness (range 21 to 35 feet) and lies 225 to 325 feet above the Lower Seam. The Upper Seam lies 275 feet above the Middle Seam and averages 18.5 feet thick (range 12 to 24 feet). The deposit is assumed to be broken into two distinct areas (A and B) by an erosional feature which separates the two areas by approximately 8,000 feet.

Area A is the larger area, covering approximately 5,000 acres between the Lower subcrop and the 400 foot cover line on the Upper Seam. Total in-place coal in this area is 250 million tons. Area B covers 3,500 acres and contains 160 million tons in place. Coal quality is somewhat variable from seam to seam and laterally within each seam. The Lower Seam is assumed to be uniformly lower in quality than the Middle and Upper Seams. The average run-of-mine heating value, including allowance for dilution, is assumed to be 7,500 Btu/lb.

Mining Method

(From Weirco, 1985)

The mining method selected for the 8 million ton/yr case and the 12 million ton/yr case was a combination of shovel-truck plus dragline stripping. The draglines are assigned to strip all material overlying the bottom seam being mined up to a maximum depth of 125 feet. The draglines selected can swing 70 cubic yard buckets at an operating radius of 300 feet. The shovel-truck fleet is used to remove all other overburden and innerburden in advance of the draglines.

The mining operation was sequenced in annual increments for the first 15 years and in 5 year blocks thereafter. Major equipment for these production levels is shown in Table 5-16. Details of these production systems are contained in the Paul Weir Company report. Of critical importance are dragline, shovel, and loader productivities. These are summarized below. Of equal importance are the work units, also summarized below.

Basic productivity of the draglines was estimated dependent on machine geometry. This basic productivity was adjusted to give effective productivities dependent on the cut geometry and rehandle requirements. Dragline with a nominal 70 cubic yard bucket was estimated to have a basic productivity index of 255,000 bank cubic yards per year per cubic yard of bucket capacity. The nominal productivity was 17,850 bank cubic yards per shift for 1,000 scheduled shifts per year. Digging in a 120 foot wide pit and excavating 125 feet of material from a bench 80 feet above the coal, a projected 46 percent of the material would have to be rehandled. Effective productivity was therefore 12,250 bank cubic yards per shift scheduled. The 6,125,000 bank cubic yards of overburden removed in the first year of coal production in producing 8 million ton/yr required 500 dragline shifts.

Shovel and loader productivities in overburden stripping, coal loading and parting removal were estimated based on the size of the machine and the size of the truck it was loading. The loading equipment was projected to operate at the average productivity estimated. Enough haul trucks were scheduled on each load center haul to keep the loaders operating. The 20 cubic yard shovel loading overburden into 120 ton trucks was estimated to have an average productivity of 5,536 bank cubic yards per shift scheduled. In the first year of coal production, 3,272,000 bank cubic yards of overburden were hauled an average of 4,000 feet to a waste dump. The number of shovel shifts required to load this amount of material was 592. The number of truck shifts required to maintain the utilization rate of the shovel was 1,895.

Work sequences of overburden removal and coal production determine the rest of the work which must be accomplished. After the mining sequence is plotted on maps and the locations of centers of mass of overburden removal are plotted, locations of spoil piles are determined. Dragline yardage is spoiled into adjacent cuts, but shovel-truck yardage must be dumped where it won't interfere with subsequent operations and will facilitate reclamation of the mine area. In most cases, initial shovel-truck spoil was dumped outside the mined area in surface dumps and only backfilled over the top of dragline spoils as the mining operation progressed.

Haul roads were laid out from the centers of mass of overburden and coal removal to the centers of mass of spoil placement or coal dumping. Average haul distances were measured and estimates of truck speeds were made dependent on the haul profiles.

If the coal seam contained removable partings, quantities were estimated and dumping locations were projected depending on the sequence of coal removal. Partings could be handled by dozing short distances in the pit, by scrapers hauling intermediate distances, or by trucks hauling to spoil dumps. Coal and overburden drilling and blasting requirements were matched to the quantities produced by the mining sequence. After the haul roads were laid out for the life-of-mine plans, sequences of construction and maintenance were developed.

Finally, reclamation plans were developed summarizing when areas would be disturbed prior to mining and when areas would be reclaimed. Generalized surface water control structure requirements were estimated.

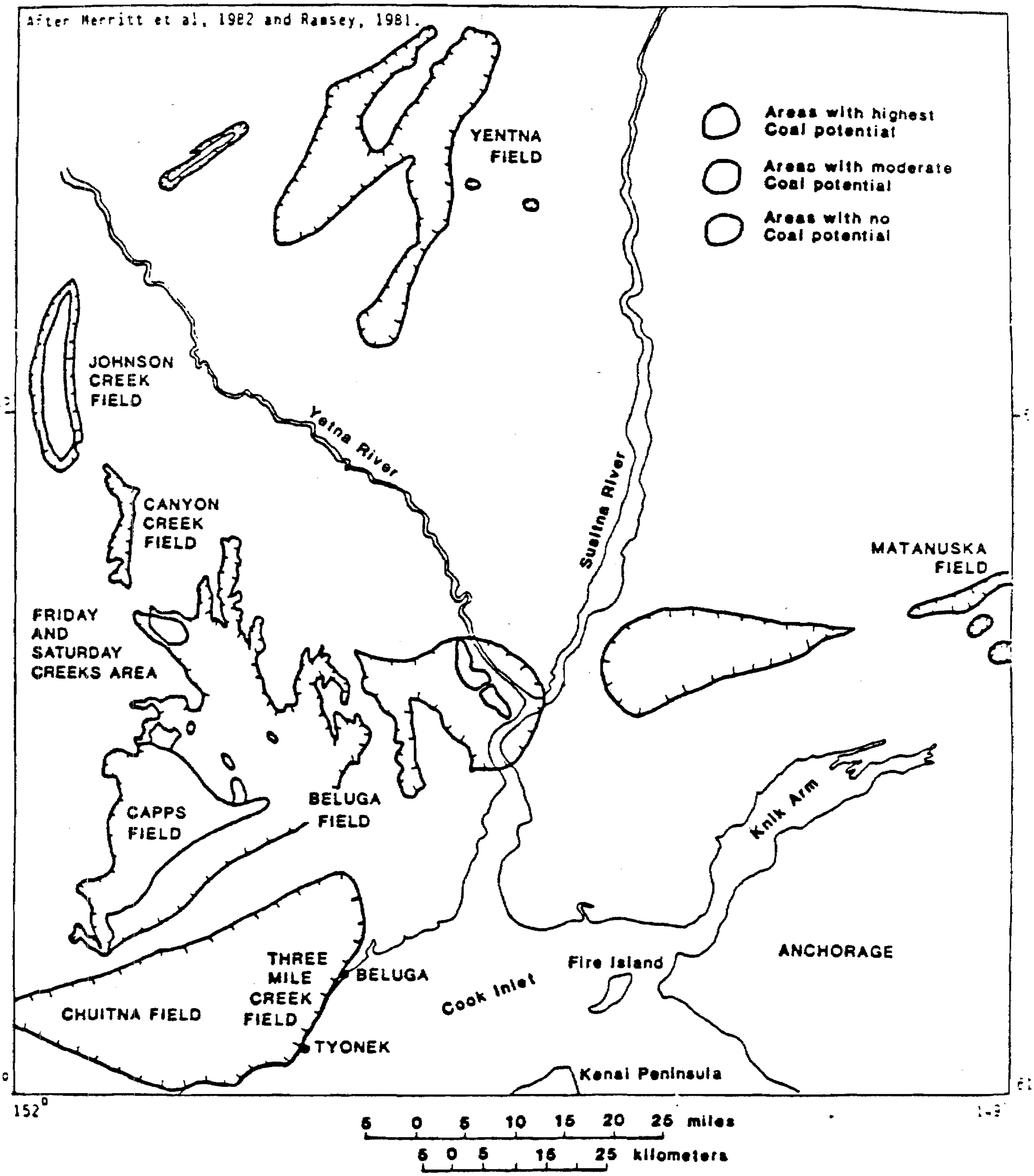
What is apparent from this analysis is that the Wierco production costs are reasonable and conservative when compared to the range of quotations by Diamond Alaska Coal Company, or when compared to the Bechtel Report. They provide a basis for minimum coal costing under worst case conditions.

5.3.3.5 Beluga Coal Production Cost Escalation

Beluga coal field projection costs will be subject to the same upward cost pressures as identified for Nenana coal. There are some notable differences between the cost escalations between Nenana and Beluga. These differences include the following: 1) Beluga mines are larger and more capital intensive than Nenana field mines; 2) Beluga coal mines are less labor intensive than Nenana field mines; and 3) Beluga coal can be burned at the mine mouth, and need not be transported by rail. These differences reduce the escalation rate associated with Beluga coal mining to 1.13 to 1.14 percent, as shown in Table 5-20.

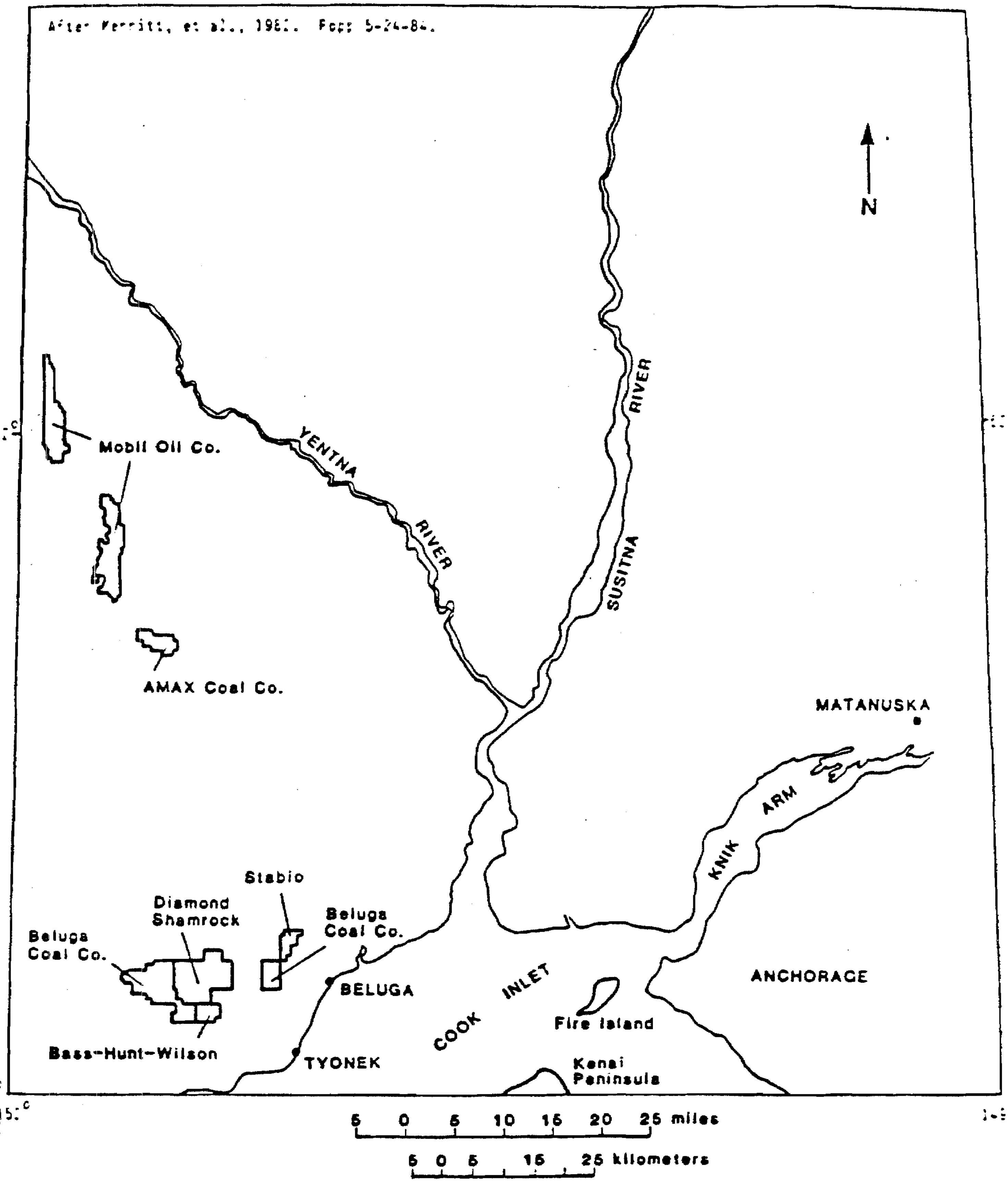
5.4 BELUGA PRICE CONCLUSIONS

This analysis leads to two basic price trends projected for the Beluga field coal--a Pacific Rim market price trend FOB Beluga and a production cost based price trend. These coal price trends are summarized in Table 5-19. Also shown on Table 5-19 and Figure 5-7 is the price trend projected for Nenana coal. (A comparison of these projections to previous coal price analysis is shown in Appendix B). It is significant to note that Beluga coal is always a lower cost option scale than Nenana coal when large scale mining operations are projected. Beluga coal costs are higher than Nenana coal costs only when small scale operations are projected for the Beluga field.



AREAL EXTENT OF COAL RESOURCES
Beluga-Yentna Coalfields and Part of the Matanuska Coalfield

FIGURE 5-1



MAJOR COAL LEASEHOLDERS
Beluga-Yenta Coalfields

FIGURE 5-2

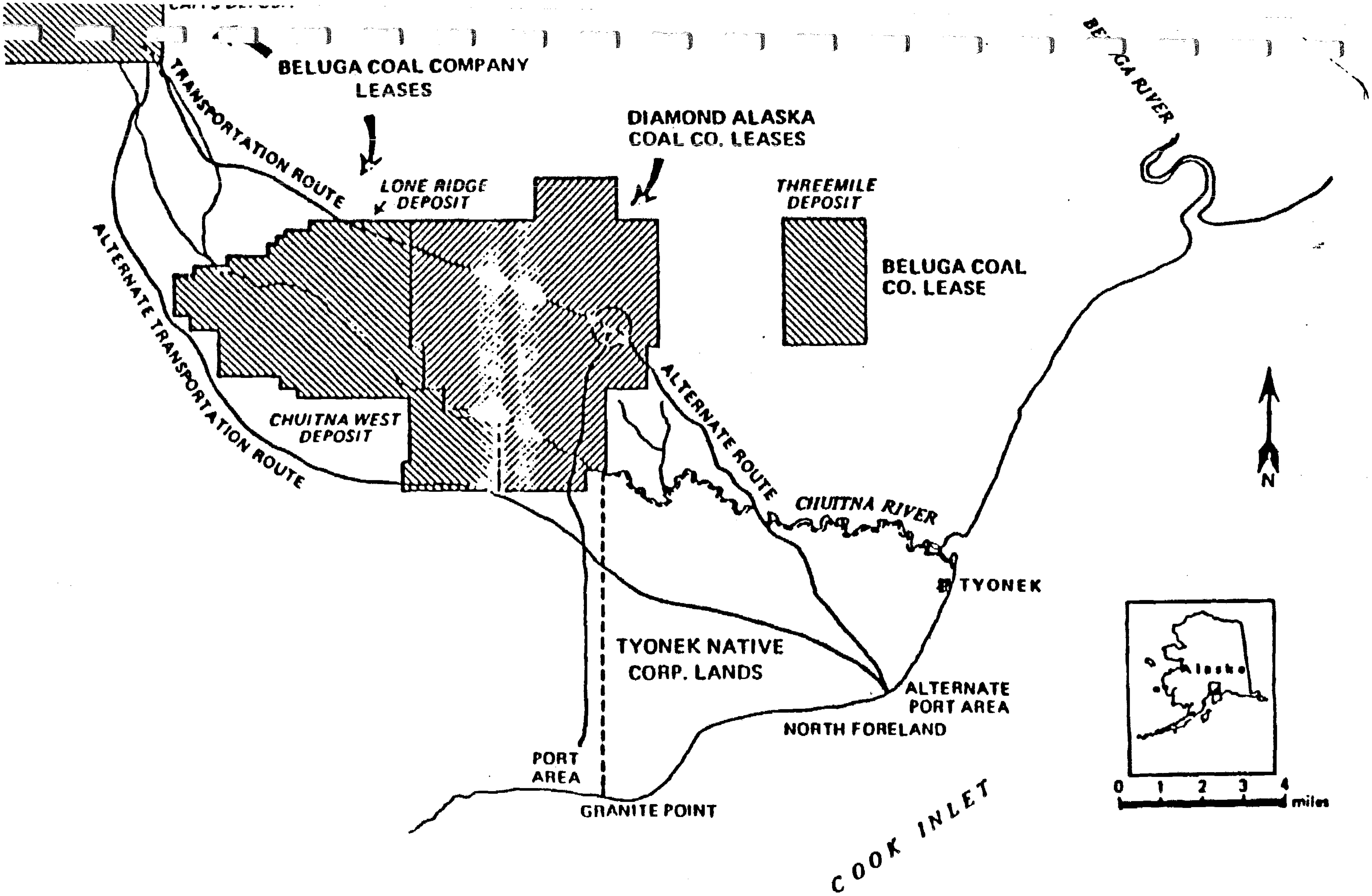

BELUGA COAL COMPANY LEASES
DIAMOND ALASKA COAL CO. LEASES
BELUGA RIVER
TRANSPORTATION ROUTE
LONE RIDGE DEPOSIT
THREEMILE DEPOSIT
BELUGA COAL CO. LEASE
ALTERNATE TRANSPORTATION ROUTE
CHUITNA WEST DEPOSIT
ALTERNATE ROUTE
CHUITNA RIVER
N
TYONEK
TYONEK NATIVE CORP. LANDS
ALTERNATE PORT AREA
NORTH FORELAND
Alaska
0 1 2 3 4 miles
PORT AREA
GRANITE POINT
COOK INLET

FIGURE 5-3

STEAM COAL PRODUCTION – 2000

AUSTRALIA, CANADA, COLORADO & WYOMING

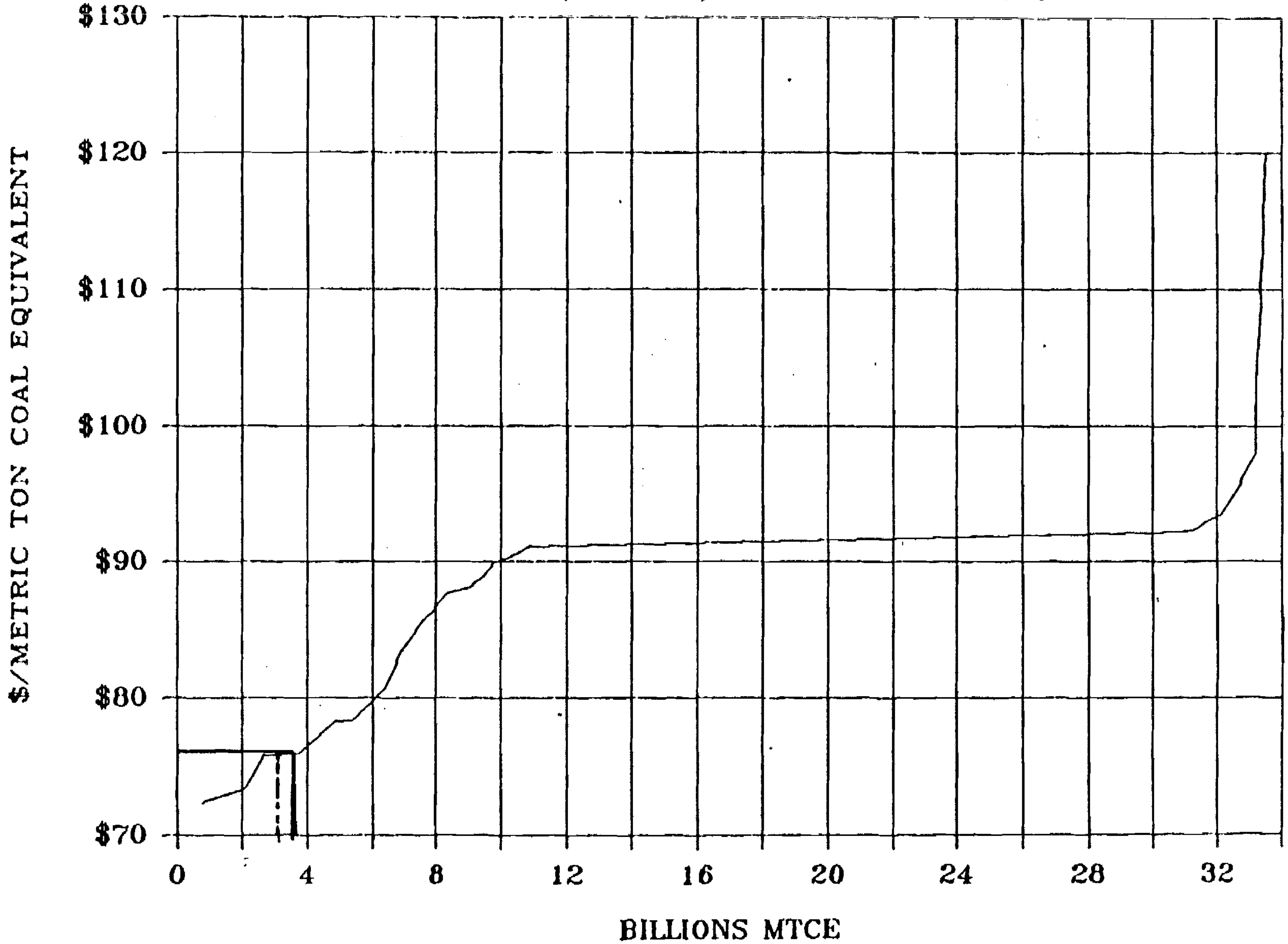


FIGURE 5-5

STEAM COAL PRODUCTION - 2040

AUSTRALIA, CANADA, COLORADO & WYOMING

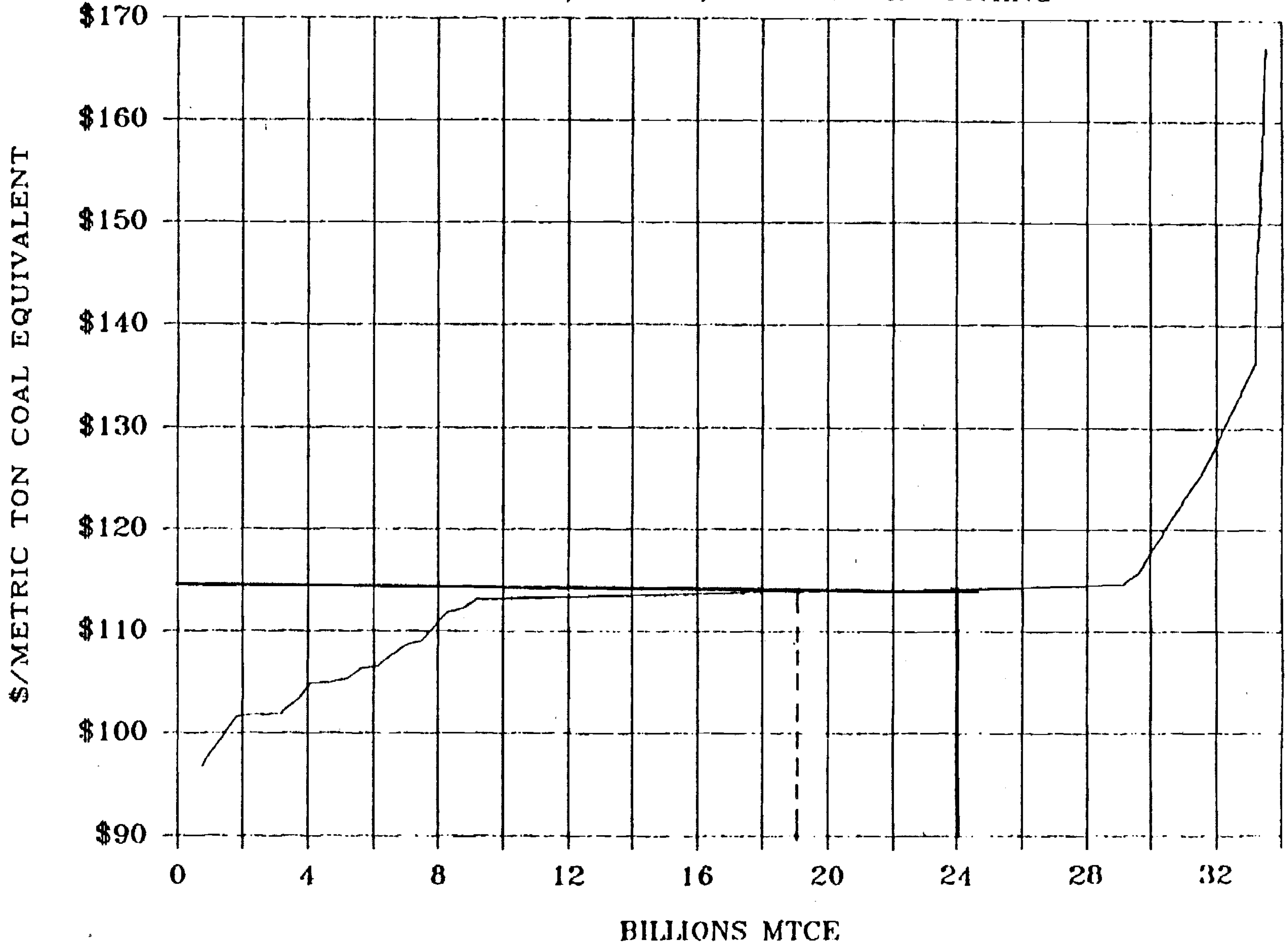


FIGURE 5-6

COAL PRICE PROJECTIONS FOR ALASKA

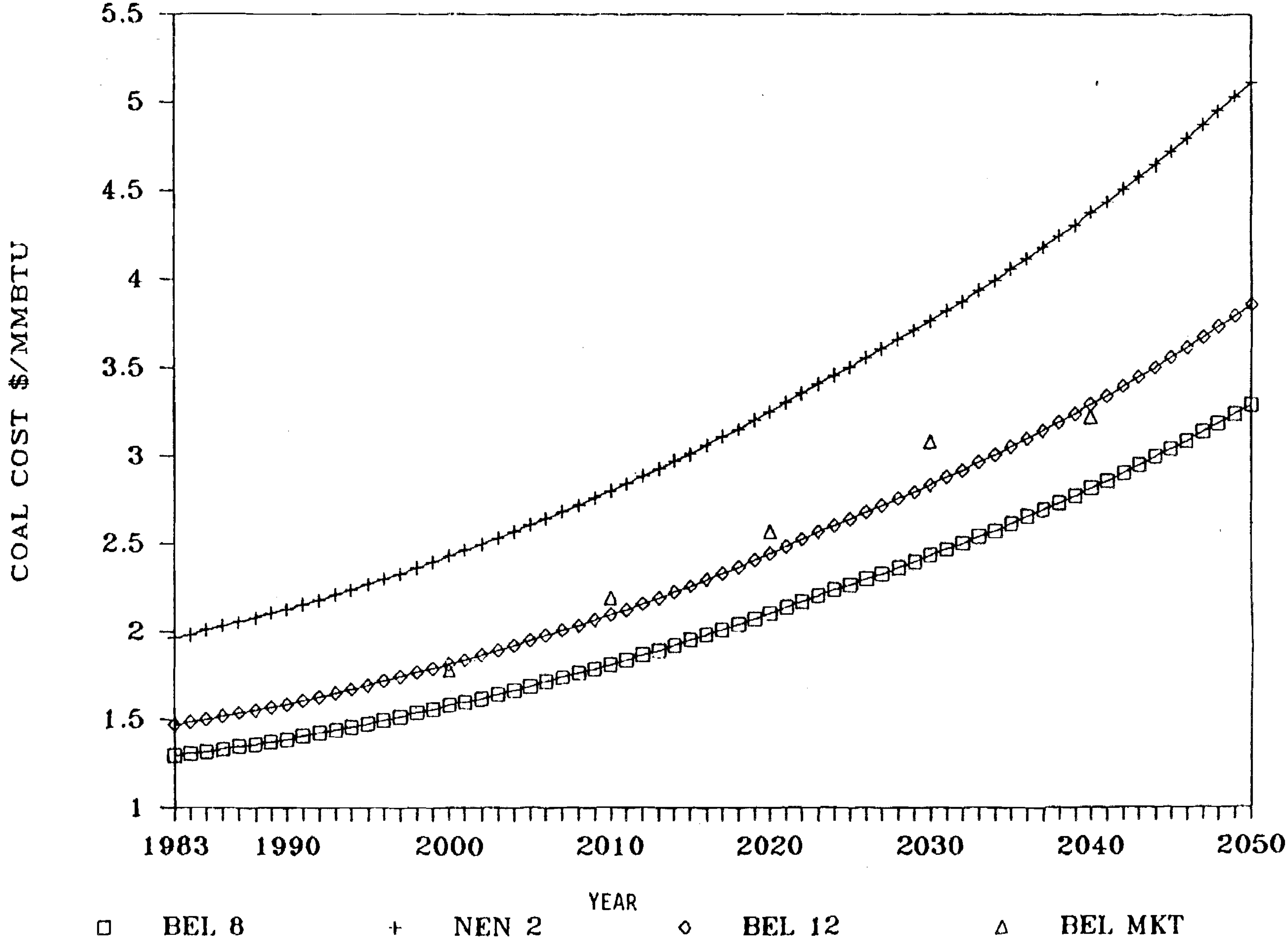


FIGURE 5-7

TABLE 5-1

DIAMOND ALASKA COAL COMPANY COAL QUALITY

	Diamond Chuitna Coal
Calorific Value (Btu/lb)	
As received	7,800
Dry basis	10,800
Total Sulfur (as received, %)	0.13
Proximate Analysis (As Received, %)	
Moisture	28
Volatile Matter	34
Fixed Carbon	30
Ash	8
Total (100%)	100
Fuel Ratio (Fc/VM)	0.88
Ultimate Analysis (Dry Ash Free, %)	
Carbon	63
Hydrogen	4
Oxygen	20
Nitrogen	1
Sulfur	0.2
Ash	11
Chlorine (Cl As Received, %)	0.05
Ash Composition (%)	
Silicon (SiO_2)	0.35
Iron (Fe_2O_3)	0.10
Aluminum (Al_2O_3)	0.21
Calcium (CaO)	0.17
Magnesium (MgO)	0.6
Sulfur (SO_3)	0.4
Phosphorous (P_2O_5)	0.1
Sodium (NaO_2)	0.2
Potassium (K_2O)	0.1
Titanium (TiO_2)	0.1

TABLE 5-1 (Continued)

DIAMOND ALASKA COAL COMPANY COAL QUALITY

	Diamond Chuitna Coal
Base Acid Ratio	0.39-0.78
Fouling Index	1.7
Grindability (Hardgrove)	29-33
Ash Fusion Temperature (°F)	
S.T. oxidizing or reducing atmosphere	2,100-2,320
F.T. oxidizing or reducing atmosphere	2,220-2,440

SOURCE: Diamond Alaska Coal Company.

TABLE 5-2

ULTIMATE ANALYSIS OF BELUGA COAL IN GILBERT COMMONWEALTH REPORT
(wt %)

Moisture	28.7
Carbon	45.6
Hydrogen	2.0
Sulfur	0.1
Oxygen	14.7
Nitrogen	0.8
Ash	8.1
Higher Heating Value	7,650 Btu/lb

SOURCE: Gilbert Commonwealth 1985.

TABLE 5-3

DIAMOND CHUITNA MARKET
PROJECTED STEAM COAL DEMAND1/
(Million Metric Tons)

Market Area	1985	1990	1995
West Coast USA	3-4	4-5	4-8
Hawaii	0.0	0-4	0-4
Alaska	1.0 (1.8-2.1%)	1-3 (1.5-3.5%)	1-4 (1.3-4.0%)
Japan	20-25	28-34	33-39
Korea	8-9	10-12	13-14
Taiwan	10-11	15-16	18-19
Hong Kong	5.0	8-11	8-12
Total	47-55	66-85	77-100

1/ Based on mid-1983 studies by JIEE, WCEC and DSC.

SOURCE: Diamond Shamrock Briefing Document, 1984.

TABLE 5-5

ACREAGES USED IN THE DIAMOND CHUITNA PROJECT

Facility	Area
Mine Area	20,000 acres
Transportation Corridor	3,400 acres 2,400 acres
Coal Terminal	700 acres
Port Facility	3,900 acres
Housing and Other Infrastructure	

SOURCE: DSC June 1984.

Footnotes (Continued)

3/ Township construction is assumed to start in late 1990s. Before that, all mining is assumed to occur in an enclave similar to the Prudhoe Bay model. Building and road construction is assumed to require a work force equal to one-half the mine construction labor force.

4/ Total direct employment is the sum of mining and construction employment.

5/ Indirect employment is assumed to equal ten percent of direct employment so long as enclave development pertains and then increases to 20 percent of direct employment after 2000. This is a low estimate. A 40 percent estimate would be a conservative higher estimate.

6/ Secondary employment is created when payrolls are spent for household services - food, education, utilities, entertainment, personal needs, etc. This is assumed to be zero so long as enclave development pertains. In 2000, secondary employment is assumed to be 20 percent of the sum of direct and indirect employment. this increases to 40 percent in 2010 and to 80 percent in 2020 and thereafter. A mining operation of the size necessary to supply coal quantities shown for 2020 would entail a real mining town complete with services that would be expected in any town. An 80 percent estimator to provide these is low and assumes a lot of spending "leakage" to Anchorage.

7/ Total employment is the sum of above.

8/ Total population is based on the enclave model in the 1990s with no nonworking dependents. By 2000, population assumes half of employed force has one dependent. Thereafter, population assumes an average of one dependent per employed worker, or a 2.0 multiple. This is a low multiple; 2.5 is commonly applied.

TABLE 5-7

DAILY SHIPPING REQUIREMENTS AS A FUNCTION OF COAL EXPORTS

Parameter	Year 2000	2010	2020	2030	2040	2050
Production (MMTY)	17	62	147	220	278	321
Ships/Day	0.7	2.5	5.9	8.8	11.1	12.8

Assumptions

1. Fastest current shiploading rate is 10,000 tons/hour (e.g., N&W Pier 6 at Norfolk).

2. A conservative operating availability for Cook Inlet conditions, assuming no more than 70 percent utilization to avoid queuing (for a single shiploader) and 75 days/year of unfavorable weather,1/ is 4,872 hours/year. Assuming an effective loading rate of 8,000 tons/hour, including adjustment for docking and moving among holds, yearly capacity would be 38,970,000 tons. N&W Pier 6 has exceeded this performance at peak conditions.

3. Each pier would consist of a causeway or trestle extending from 3,000 to 7,000 feet offshore (depending on location) to reach a MLL water depth of 60 feet. Each pier could support two shiploaders with separate mooring points, in a "Y" arrangement, with the ships hull in line with the tidal flow.

4. Average ship size: 50 percent in 120,000 DWT
   50 percent in 50,000 DWT
   Average = 85,000 DWT

   For each 10,000,000 tons: 117 shiploads, or 0.4 per shipping day (290 days/year).

1/ Probably only 15 to 20 days/year when loading impossible based on Union Oil Company experience at Niskiska (conversation with Harold Pilond, Union Oil Company, 11/29/84).

TABLE 5-9

RESERVE COMMITMENTS[1] BY YEAR AND SOURCE[2]
(Million MTCE)

	2000	2010	2020	2030	2040
Australia	1.89	3.41	4.09	4.77	6.47
Canada	2.01	3.45	3.45	3.45	3.45
Colorado	0.00	1.04	2.73	8.65	13.85
Wyoming	0.00	0.00	2.73	8.65	13.85
TOTAL	3.90	7.90	13.00	19.60	26.50

1/ From detailed supply tables, see Dames & Moore, 1985.
2/ Supply not including Alaska coal, but including Chinese coal.

TABLE 5-10

ESTIMATED PACIFIC MARKET PRICES BY YEAR WITHOUT ALASKA EXPORTS1/
(1985 $ Price CIF Japan)

	2000	2010	2020	2030	2040
No Wyoming Constraint2/					
$/MTCE	76	93	102	109	115
$/MMBtu	2.73	3.35	3.67	3.92	4.13
With Wyoming Constraint3/					
$/MTCE	76	93	102	119	125
$/MMBtu	2.73	3.35	3.67	4.28	4.50

1/ Derived from Dames & Moore supply/demand analysis. See text.

2/ Prices as derived from comparison of demand with solution curves.

3/ Price including added cost for Wyoming coal in 2030 and 2040 of additional ocean freight from Portland, Oregon or other shallow port, as discussed in Section 3.5.2.

TABLE 5-11

PROJECTED EXPORTS OF MAJOR PACIFIC RIM STEAM COAL EXPORTERS 2000-2040 WITHOUT ALASKA COAL 1/
(Million MTCE)

	1990 2/	2000	2010	2020	2030	2040	Reserve Commitment in 2040 3/
Australia 4/	70	85	93	112	113	120	6.48
Canada	18	55	55	55	60	60	3.45
Colorado			19	56	66	66	2.73
Wyoming			75	126	237	317	13.84
Subtotal							26.32
China 5/	16	25	43	61	84	99	
TOTAL	104	165	288	410	560	662	

1/ Dames & Moore estimates based on composited coal supply curve.

2/ Actual 1990 supply will probably not resemble this mix because it reflects: 1) longer term supply economics and 2) eliminates minor suppliers (i.e., USSR).

3/ Calculated by arithmetic average of each ten-year interval of exports plus production from 2040 to 2060.

4/ Includes domestic production in New South Wales and Queensland, Australia.

5/ Chinese exports estimated at 15 percent of total imports.

TABLE 5-12

PACIFIC RIM MARKET PRICES FOB ALASKA, QUALITY ADJUSTED
(Million MTCE)

	2000	2010	2020	2030	2040
Pacific Delivered Price ($/MTCE)1/	73	88	99	121	143
Ocean Freight, Alaska-Japan ($/MTCE)2/	13	14	15	16	17
Port and Inland Transport in Alaska ($/MTCE)3/	10	10	11	11	12
Net FOB Mine ($/MTCE)	50	64	73	94	114
Net FOB Mine ($/ton)4/	27	34	39	50	61
Net Adjusted for Quality ($/MMBtu)5/	1.67	2.16	2.47	3.19	3.87

1/ Table 5-11.

2/ Source: Dames & Moore August 1985 Report.

3/ Appendix E of Dames & Moore November, 1984 report.

4/ Net FOB price per short ton for 7,500 Btu/lb Beluga coal.

5/ Net FOB mine price/MTCE divided by 27.8 million Btu/MTCE times 0.95; discounting for moisture.

TABLE 5-14

REVISED RESERVE COMMITMENTS OF COMPETING SUPPLIERS
ACCOUNTING FOR ALASKA COAL EXPORTS

	2000	2010	2020	2030	2040
Original Reserve Commitment (billion MTCE) 1/	3.9	7.9	12.9	18.1	24.0
Revised Reserve Commitments 2/	3.4	6.8	11.8	14.5	18.8
Revised Pacific Market Price ($/MTCE) 3/	76	90	103	119	125
Revised Alaska Netback Price ($/MMBtu quality adjusted)	1.78	2.19	2.57	3.08	3.22

1/ Table 5-10.

2/ Reduced by reserve commitment of Alaska coal, calculated from Alaska exports in Table 5-15.

3/ Derived from supply/demand analysis.

TABLE 5-15

EXPORTS[1/] AND RESERVE COMMITMENTS[2/] OF ALASKA COAL
2000-2040
(Million MTCE Except Where Noted)

	2000	2010	2020	2030	2040
Alaska Exports Million MTCE	16	40	67	92	114
Alaska Exports Million Tons[3/]	31	78	131	179	222
Cumulative Exports Million MTCE	64	344	879	1,674	2,704
Reserve Commitments Billion MTCE	0.4	1.1	2.1	3.6	5.2
Reserve Commitments Billion Tons	0.75	2.2	4.3	7.2	10.0

1/ See Table 5-14.

2/ Reserve commitments are the sum of cumulative production plus 20 times the production in that year.

3/ Converted from MTCE based on 7,500 Btu/lb for Beluga coal, less five percent of Btu content to account for the higher moisture compared to competing coals.

TABLE 5-16

MAJOR EQUIPMENT FOR LARGE-SCALE COAL MINES IN THE BELUGA FIELD

Equipment Item	Production Level 8×10^6 ton/yr Equipment Size	 12×10^6 ton/yr Equipment Size
Overburden Draglines	70 cubic yards	One 70-cubic yard and one 110-cubic yard
Overburden Shovels	20 cubic yards	20 cubic yards
Coal Loaders (Hydraulic)	18.5 cubic yards	18.5 cubic yards
Overburden Haulers (Rear Dump)	120 tons	120 tons
Coal Haulers (Rear Dump)	120 tons	120 tons
Graders	16-foot blade	16-foot blade
Dozers	300 and 400 hp	300 and 400 hp
Scrapers	31 cubic yards, twin engine	31 cubic yards, twin engine

SOURCE: Wierco 1984.

TABLE 5-17

SUMMARY OF RESULTS
HYPOTHETICAL MINE STUDIES FOR LARGE BELUGA MINES

Parameter	Production Rate 8 Million Ton/Yr	Production Rate 12 Million Ton/Yr
Mine life (years)	30	30
Average stripping ratio	6.75	6.93
Personnel Requirements		
Operating	297	473
Maintenance	306	505
Salaried	88	113
Total	691	1,091
Tons per manshift	46.3	44.0
Capital Investment		
Initial investment (thousands)	$277,176	$424,369
Initial investment per annual ton	$34.65	$35.36
Life of mine investment (thousands)	$573,660	$866,420
Average Annual Operating and Maintenance Costs (Per Ton)	$11.38	$11.71
Average depreciation of total capital	$ 2.48	$ 2.46
Average Total Production Costs	$13.86	$14.17

TABLE 5-17 (Continued)

SUMMARY OF RESULTS
HYPOTHETICAL MINE STUDIES FOR LARGE BELUGA MINES

Parameter	Production Rate 8 Million Ton/Yr	12 Million Ton/Yr
Levelized Coal Price Per Ton		
At 8.2 percent real discount1/ (1985$)	$17.50	$18.34
Levelized Coal Price Per Million Btu2/		
At 8.2 percent real discount rate1/ (1985$)	$1.17	$1.22

1/ Reflects nominal rate of return of 14.5 percent and underlying rate of inflation of 5.5 percent.

2/ Assumes 7,500 Btu/lb.

TABLE 5-18

COMPARISON OF WEIRCO ESTIMATES FOR A LARGE MINE TO BECHTEL ESTIMATES FOR A 7.7 MILLION TON/YR BELUGA FIELD MINE

Parameter	Bechtel Estimate Dec. 1979 Dollars	Bechtel Estimate Jan. 1985 Dollars 1/
Capital costs (total)	$277-492 million	$389-690 million
Operating and maintenance costs ($/yr)	$54-78 million	$76-109 million
Coal price at 75 percent debt, 25 percent equity financing ($/million Btu)	$1-1.30	$1.40-1.80
Wierco estimate ($/million Btu)		$1.17-1.22

1/ Escalation is 1.403.

TABLE 5-19

BELUGA COAL PRICES COMPARED TO PRODUCTION COSTS
($1985/Million Btu)

Year	Pacific Market Price FOB Mine	Production Cost
1985		1.17
1990	--	1.26
1995	--	1.36
2000	1.78	1.46
2010	2.30	1.69
2020	2.57	1.96
2030	3.08	2.27
2040	3.22	2.63
2050	3.37	3.04

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APPENDIX A

ESTIMATED COST OF CAPITAL FOR AN AVERAGE COAL COMPANY

In order to analyze the production cost of coal, the Harza-Ebasco Joint Venture calculated the cost of capital for coal mining companies. The first calculation was for the cost of equity capital using the conventional Capital Asset Pricing Model:

$$k_e = k_{rf} + \beta_j (k_m - k_{rf}) \tag{1}$$

Where k_e is the after tax cost of equity capital, k_{rf} is the risk-free cost of capital, β_j is the measure of systematic risk for the company as a whole, and k_m is the cost of capital in the equity market as a whole. The β_j term is set at 1.00 for firms with average systematic risk. The term k_m is defined as the cost of capital for companies with an average β_j (β_j=1.00).

Following calculation of β_j, we calculated the unleveraged risk measure, β_u, for the coal industry. Such a measure provides a cost of capital consistent with the Paul Weir Company model, where neither debt interest nor principal repayment are considered as cost items. That model assumes a 100 percent equity funded project. The formula for calculating β_u is as follows:

$$\beta_u = \frac{\beta_j}{1 + \frac{\theta(1 - TR)}{1 - \theta}} \tag{2}$$

Where θ is defined as debt/total capital. The term $1 - \theta$ is the proportion of a corporation's capital structure that is equity. β_u is then substituted for β_j in equation (1).

Table A-1 is a compilation of β_j, θ, and calculated β_u terms for a sample of coal companies as of spring, 1985. These data are the basis cost of capital analysis.

The rate of inflation for 1984 was about 4 percent. The 5-10 year expectation was apparently between 5 and 6 percent. The expected rate of inflation is treated as 5.5%, consistent with APA analyses. Typical risk-free cost of capital rates were 8.02 percent. The historical risk premium for $\beta_j = 1.00$ is .089.[1] On that basis, equation (1) is solved as follows:

$$k_e = .0802 + 0.65\ (.187 - .098) = 0.142 \tag{3}$$

This nominal unleveraged equity value is then deflated as follows:

$$\frac{1.142}{1.055} - 1 = 0.082 \tag{4}$$

This provides real cost of capital of 8.2%. The discount rate terms, then, are 2.4% premium for early availability of funds 5.5% inflation, and 5.7% for risk.

1. Mullins, D.W., 1982. Does the Capital Asset Pricing Model Work? Harvard Bus. Rev. 60(1):105-114.

TABLE A-1

COST OF CAPITAL PARAMETERS FOR SELECTED
COAL MINING AND RELATED COMPANIES
SPRING, 1985

Company	Value Line β_j	Parameter θ	Calculated β_u
Denison Mines	0.90	0.64	0.47
Eastern Gas and Coal	0.95	0.43	0.62
Kaneb Services	1.15	0.49	0.69
Mapco, Inc.	1.00	0.35	0.76
North American Coal	0.85	0.84	0.17
Pittston Company	1.15	0.17	1.00
Pyro Energy Corporation	1.15	0.49	0.63
Westmortand Coal	0.80	0.23	0.65
Diamond Shamrock	1.05	0.34	0.83
Average	1.00	0.44	0.65

APPENDIX B

A COMPARISON OF COAL PRICE PROJECTIONS FOR ALASKA

It is useful to compare the coal price estimates of this document to Alaska coal price projections made previously. Previous estimates were as follows:

Estimator	Year
Battelle Northwest Laboratories; Railbelt Study	1982
Acres American; Susitna License Application	February 1983
Harza-Ebasco Susitna Joint Venture; Susitna License Application (and Economic and Financial Update)	July 1983 (February 1984)
Paul Wier Company, Dames and Moore, and Sherman H. Clark Assoc.; Comments to Draft Environmental Impacts Statement (DEIS)	August 1984
Dames and Moore and Harza-Ebasco (current)	April 1985

The base values for all of these estimates are shown in Table B-1. These prices have been levelized for the 67 year period, 1983-2050. The levelizing factors include the base price and real escalation rates shown in Table B-1, and a 3.5 percent real discount rate.

TABLE B-2

67 YEAR LEVELIZED[a/] ALASKA COAL PRICE ESTIMATES
(1985 $/BTU X 10^6)

	Coal Field			
	Nenana		Beluga	
	Estimate	%Difference from Mean	Estimate	%Difference from Mean
Mean	$2.83	N/A	$2.48	N/A
Battelle, Railbelt	$3.23	+14.1%	$2.85[b/]	+14.9%
Acres, License Appl.	$2.90	+2.5%	$2.26	-8.9%
Harza-Ebasco, License Appl. & E & FU	$2.47	-12.7%	$2.62	+5.6%
DEIS Comments	$2.63	-7.1%	$2.46	-0.8%
APA/current	$2.90	+2.5%	$2.20[c/]	-11.3%

a/ Real discount rate = 3.5%
b/ Average of production and netback prices per Battelle methodology
c/ Market value in Alaska

The levelized cost results are shown in Table B-2. It is significant that all coal cost estimates are within +15 percent despite the wide variety of estimators and the different time periods of analysis. The variations about the mean values ($2.56 for Nenana and $2.24 for Beluga) are less than +10 percent. If the highest values, the Battelle Railbelt estimates, are removed from the basis of analysis. Given the long time horizon of these projections, 67 years, these estimates appear to be quite consistent with each other.

TABLE B-1

COMPARISON OF COAL PRICES
(Base = 1985; 1985 dollars)

Study	Coal: Nenana: Nenana (delivered in Base	Esc.)	Beluga: Production Base ($/MMBTU)	Esc. (%)	Market Value in Alaska Base $/MMBTU)	Esc. (%)
Battelle, 1982a/	$1.99	2.0%	$1.49	2.1%	$1.91 b/	2.1%
Acres, Feb. 1983	$2.02 a/	1.5% b/			$1.65	1.6% c/
APA, July 1983	$1.87	2.3% d/			$2.02	1.6% d/
E & FU, Feb. 1984	$1.87	1.2%			$2.02	1.1%
DEIS Comments, August 1984	$2.03	1.1%			($1.56) e/	1.8%
APA Current, Nov 1985	$2.02	1.5%	$1.30	1.1%	($1.47) e/	2.1%

a/ Escalated to 1983 dollars from 1982 dollars at 6 percent inflation escalated to 1985 at real rate of 1.0 percent/year;

b/ Battelle averaged the two values

c/ Derived from Acres 2.3 percent, 1983 - 2000 and 1.1 percent, 2000 - 2040

d/ Derived from Acres 2.6 percent, 1986 - 2000 and 1.2 percent, 2000 - 2040

e/ Deflated from year 2000 values