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ASSESSMENT OF COAL RESOURCES OF NORTHWEST ALASKA PHASE II

Volume III

**Assessment of the Feasibility of
Utilization of Coal Resources of Northwestern
Alaska for Space Heating and Electricity**

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The State of Alaska
Alaska Power Authority
334 W. 5th Ave.
Anchorage, Alaska 99501

By

Dames & Moore

ALASKA POWER AUTHORITY

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SUMMARY AND RECOMMENDATIONS

CONCLUSIONS

The study reported herein was conducted to determine preliminary feasibility of substituting local coal for imported diesel fuel as an energy source for electric power generation and space heat in the northwest Alaska study area.

The study examined the following basic parameters:

- Coal occurrences
- Mining concepts
- Transportation modes
- End-use technologies

Dames & Moore concludes that it appears feasible to supply the space heat needs for the majority of the study area with coal. This would eliminate the need for 5.6 million gallons of diesel fuel annually by the year 2000. Electrical power can also be economically supplied by coal in the larger communities of Kotzebue, Nome, Unalakleet, and possibly Selawik.

We find that any coal resource that meets the following criteria is worthy of further evaluation:

- Heat value of 10,000 Btu/lb.
- Reserves sufficient to supply 60,000 to 100,000 tons per year for 20 years.
- Surface minable.
- Barge accessible--either coastal or riverine, or within about 20 miles of such access.

According to our analysis, coal from such a resource could be centrally mined and shipped by tug and barge to the majority of villages in the study area for approximately \$80 to \$365 per ton, depending on transportation distance. This translates into the equivalent of delivering diesel fuel to a village for \$0.52 to \$1.36 per gallon. The average diesel price today is about \$1.50 per gallon.

The principal factors underlying the above are:

1. The cost of transporting coal has significant impact on energy cost to the user. The best approach is to deliver coal by a 500-ton barge, which can be beached and off-loaded by a front-end loader.
2. The quality of coal has a significant impact on consumer cost. Hence, Chicago Creek's 6500-Btu/lb resource is more expensive as a whole than the resources of the Cape Lisburne to Point Lay region, which have indicated values of 10,000 Btu/lb or higher.
3. The cost of mining has relatively little impact on consumer cost if a single mine furnishes coal for the whole study area.
4. Power plant capital and operating costs have significant impact, and currently only Nome, Kotzebue, Unalakleet, and perhaps Selawik could justify coal-fired village plants.
5. The cost of transmission lines has significant impact on the price of electricity to consumers.

TASK BY TASK SUMMARY

The study undertook the following principal tasks:

- Task 1: To determine which coal use technologies are available and appropriate to northwest Alaska and to forecast energy demand.
- Task 2: To review known coal occurrences and determine which occurrences are most suitable for meeting energy demand; and to propose mine concepts and estimate mining costs.
- Task 3: To explore feasible coal transportation modes and determine their costs.
- Task 4: To combine the information of the first three tasks to establish the overall feasibility of coal utilization.

The following is a task-by-task summary of the main finding of this study:

Task 1 - Fuel Requirements and Coal Use Technology Selection

An energy demand forecast for each community in the study area is shown in Table 1-1. This table separates the heating and electric generating demands, all expressed in diesel equivalents. Heating demand per capita varies widely due to the differences in the size of public and commercial sectors relative to the residential sector. Projections were based on the slow population growth forecast by Alaska Department of Transportation and Public Facilities (1980). The same energy requirements (for the year 2000) expressed in coal equivalents are shown in Table 1-2. Assuming that the study area space heating needs are served 10 percent by electricity and 90 percent by coal, a total of 57,000 tons of coal would be needed annually to provide heat and 35 million kilowatt-hours of electricity.

Coal-fired steam turbines are the most easily adapted method of coal/electric conversion. Coal liquification is too large scale to be appropriate to the study area. Coal gasification may be feasible, but since it is beyond the current state-of-the-art, it was not addressed in this study.

Small coal coal-fired turbine generators are available, at least above the one-megawatt scale. However, the small plants appropriate to the study area show marked diseconomies of scale. Estimated turn-key power plant costs are shown on Table 1-3. Three-wire AC overhead lines are judged to be the best method of power transmission. Such lines would cost roughly \$150,000 per mile, installed, with an annual operation and maintenance cost of \$10,000 per mile. This high cost makes transmitting power more than 30 miles economically unattractive.

Coal could also be burned directly in homes to provide space heat, using efficient modern stoves. At least twice as much heat can be produced from each pound of coal by direct burning (compared to electric space heat).

Task 2 - Coal Occurrences and Mining Concepts

As determined in Phase I of this study (Dames & Moore, 1980) a large number of coal occurrences are present within the study area. However, since few of these occurrences have been mined or even explored in sufficient detail to permit estimation of reserves, the extent of the resource base is speculative.

The existing data on occurrences, and their relative suitability for supplying the area's energy needs are displayed in Table 2-1. Surface mining is clearly preferable to underground mining in the area. The estimated costs of surface mined coal vary as a function of scale of operation (see Table 2-5). In general, larger mines offer some economies of scale, with cost ranging from \$52 per ton for 500-ton-per-year mines to \$42 per ton for 60,000-ton-per-year mines. (These are mine-mouth costs and do not include transportation). Mining plans for developing both surface and underground coal mines of alternative sizes are given in Appendix II.

Task 3 - Coal Transportation Modes

Feasible transportation modes include 2 and 20-ton trucks moving over summer haul roads, and river and coastal barges. All haul roads would have

to be constructed for this purpose at an initial cost of \$175,000 per mile, for a single lane road. Annual capital charge and maintenance for such a road would cost about \$14,500 per mile. This per mile cost is assumed fixed, even if tonnage moved over the road is low, resulting in marked diseconomies of scale for delivering small tonnages.

Selection of trucks for hauling coal depends on the distance over which coal from the given mine would be moved, and the amount of coal. For analytical simplicity, only 20-ton and 2-ton trucks were considered. The selection of appropriate vehicles, and the extent to which they would be fully utilized, is shown in Table 3-5. The corresponding levelized cost per ton-mile is shown in Table 3-6. The use of off-road vehicles and winter roads may be feasible for small quantities, but the practicality of moving coal in winter is dubious. Furthermore, equipment is needed to develop and maintain winter roads. Such equipment would be too costly for the small inland communities in which it would be needed. Therefore, this winter road alternative is considered infeasible.

Barges are the most feasible means of moving coal over long distances. Further, a 500-ton shallow draft barge can be beached and off-loaded by a front-end loader. A tug and 500-ton barge combination could average 100 statute miles a day and reach most every community in the study area, at a daily operational cost of about \$7,000. Table 3-2 presents a breakdown of barge costs per ton of coal delivered.

Task 4 - End-Use Scenarios and Sensitivity Analysis

On the basis of the study area analysis of demand, electrical technology, coal resources, and transportation modes, completed in the first three tasks, the feasibilities of specific end-use scenarios were analyzed. The Kotzebue to Kobuk portion of the study area is the focus of this analysis. Three degrees of electrical generation centralization were considered: regional, subregional, and local. Each of these options was represented by several possible subscenarios. The results of these analyses are summarized in Tables 4-5 and 4-6, with the details presented in Appendix V.

Kotzebue is the community in the region that exhibits the greatest economies of scale and lowest cost for energy. The regional scenarios reflect these economies by their weighted average costs (Appendix V) per KWH, which are strongly influenced by Kotzebue.

The regional scenarios use coal from four separate sources within the Kotzebue-Kobuk vicinity, including Chicago Creek. Two separate scenarios mine coal at Chicago Creek and Cape Beaufort, and deliver the coal by barge.

In the Kotzebue-alone scenario that uses Chicago Creek coal, the weighted average electricity cost comes out at \$0.20 per KWH. Under the Cape Beaufort scenario, the cost drops to \$0.14 per KWH, reflecting higher quality coal and cheaper transportation. Cost of electricity under the various scenarios ranges from \$0.14 per KWH for Kotzebue to \$3.18 per KWH (for Kobuk generating its own).

Cost of delivered coal for space heating under various scenarios, and using various sources, ranges from \$80 to \$365 per ton, depending on transport distance and mode.

4.6 ACTION RECOMMENDATIONS

It will be feasible to replace 90 percent of existing diesel needs with coal, assuming that the local coal reserves prove out. If the \$7.3 million dollars now spent on imported diesel can be retained in the local economy, a significant step toward regional economic independence will have been taken. To bring coal use into reality, the following actions in order of importance are recommended:

1. Coal Occurrences: Those coal occurrences which are at or within 30 miles of the coast, are mineable by surface methods, and which have a heat value of at least 10,000 Btu should be explored. These areas are presented below. Subsequent to delineation of reserves, data acquisition and analysis of site-specific development schemes are warranted to verify the conclusions of our broad-based study, including mine, road, and port concepts.

2. Mine Ownership: The ownership status and regulatory complexity of surface mining at the promising occurrences should be determined. These factors may significantly influence the site selection.
3. Electric Utilities: The electric utilities at Kotzebuk, Nome, Noorvik, Selawik, Point Hope and Unalakleet should be advised of the potential feasibility of coal-fired generation.
4. Social Acceptance: The social acceptability of home coal use should be evaluated. Potential users should be made aware of the availability of efficient coal and wood stoves.
5. Electrical Generation: Small coal-fired power plants for the majority of villages do not appear feasible. Cost per single units would be high since, although the technology exists, it is no longer commercially available. The cost of small coal-fired steam turbine plants should be determined based on bid solicitation for a 100 to 200-KW plant on a turn-key basis (designed, fabricated, delivered, and installed). The cost may be considerably lower than that reported in this study if a bulk order (more than 10 units) is tendered. Units would require minimal maintenance, automatic shut-down (for unattended operation), a semi-automatic feed, and freeze protection in case of shut-down. The possibility of district heating (using waste heat from the power plant) should be evaluated as well.

RECOMMENDED AREAS FOR FURTHER EXPLORATION

<u>Exploration Priority</u>	<u>Area⁽¹⁾</u>	<u>Comments</u>
1.	Point Lay (Areas 2A, B, C) Upper Kukpowruk River	High thickness of total coal (especially Area 2C with 20-foot bed) and relatively low dips (6 - 20 degrees) make stripping ratios favorable.

⁽¹⁾Refer to Plate 1 of Phase I report, Volume II.

<u>Exploration Priority</u>	<u>Area</u> ⁽¹⁾	<u>Comments</u>
2.	Deadfall Syncline (Area 6) About 30 miles south of Point Lay, along Cape Beaufort	Coal up to 15 feet thick drilled in low-dip area within 20 feet of surface. Drilling data available.
3.	Point Lay (Area 1B) Lower Kukpowruk River	Total coal is 18 feet, but with dips of 30 - 40 degrees; unfavorable stripping ratios.
4.	Corwin-Thetis (Area 8) Lower Cape Beaufort cliffs about 80 miles southwest of Point Lay.	Corwin least desirable because of very high dips; with max dip of 24 degrees at Thetis area, stripping ratio unfavor- able because of low total coal thickness recorded (10 feet).

⁽¹⁾Refer to Plate 1 of Phase I report, Volume II.

INTRODUCTION

BACKGROUND

Over the past decade (1970-1980), the prices of virtually all petroleum products have increased substantially. Although highly developed economies have been able to adjust to these escalated prices, many lesser-developed economies have not. Northwest Alaska (Figure 1) exemplifies a region that has been adversely impacted by increased petroleum prices. Because much of the population of northwest Alaska relies on seasonal employment to obtain income, it has become difficult for the local inhabitants to meet their fuel and electricity expenses. For this reason, the Alaska Power Authority (APA) has undertaken a series of studies to assess the existing and future energy requirements of northwest Alaska communities, and to determine the economic-sociostrategic feasibility of developing alternative energy resources of the region. Through conduct of these investigations, the APA hopes to determine ways in which the communities of northwest Alaska can achieve a greater degree of energy independence.

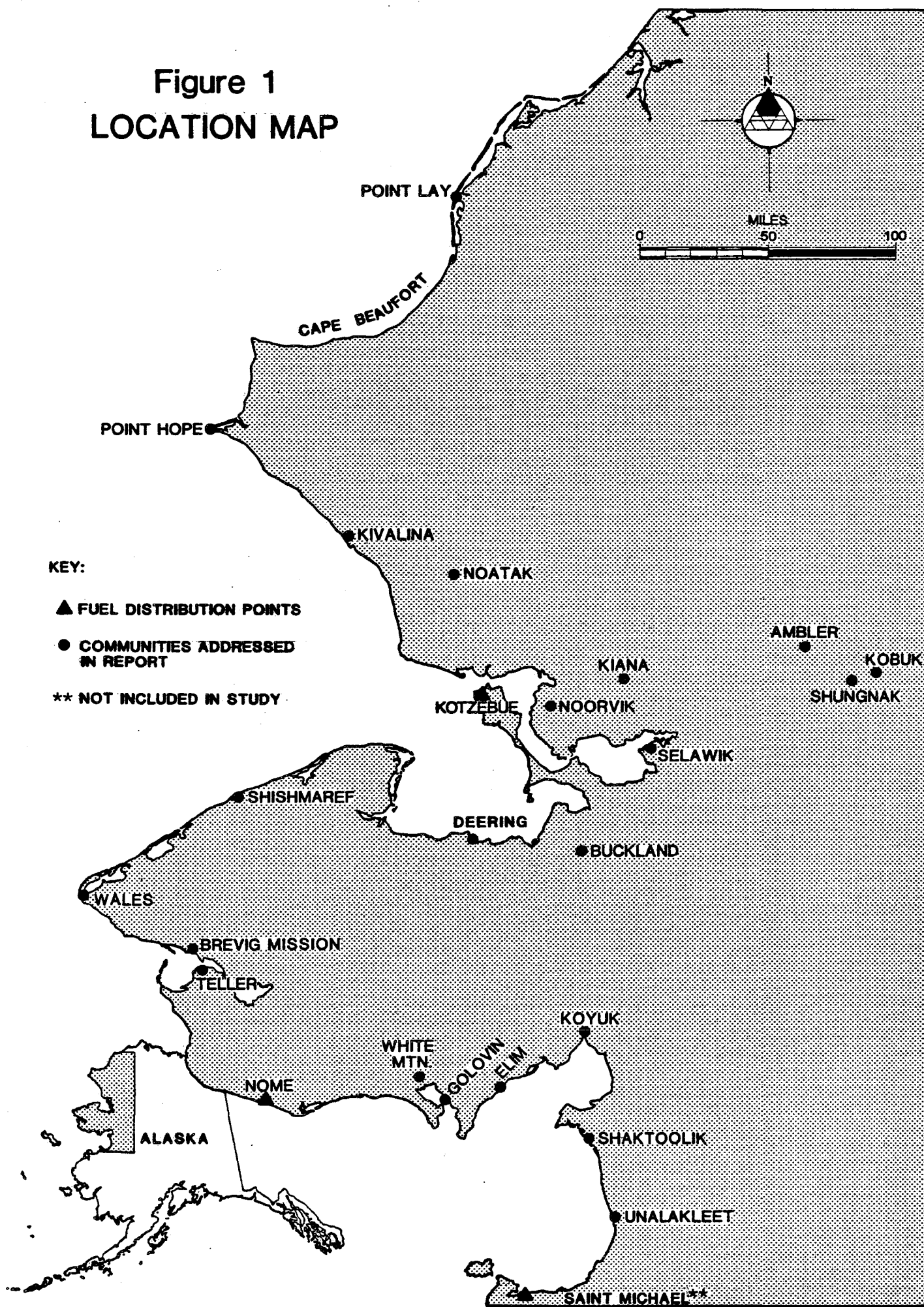
The local energy resources of northwest Alaska that have been or are currently being investigated include coal, wind, geothermal, and hydro occurrences.

This study focuses on the utilization of local coal deposits for space heating, electricity generation, or both.

PURPOSE AND SCOPE OF INVESTIGATION

Given APA's interest in promoting the energy self-sufficiency of northwest Alaska, the agency issued in early August 1980 a request for proposals to assess the extent and quality of, as well as the socioeconomic practicability of developing the coal resources of northwest Alaska. Toward this end Dames & Moore, in conjunction with its subcontractor Resource Associates of Alaska, proposed to the APA a scope of work to accomplish this research.

Figure 1
LOCATION MAP



Dames & Moore divided the work into two principal phases. Phase 1, completed in December 1980, consisted of two major tasks:

- Determine existing fuel utilization rates and patterns by villages within the study area, and
- Identify coal resources in northwest Alaska that may be suitable substitutes for petroleum-based fuels in village electrical and heating applications.

The data developed in Phase 1 were used as a basis for Phase 2, which consisted of the following four tasks:

- Develop criteria regarding power plant or space heating fuel requirements from a quality (Btu) and quantity (annual tons of coal) standpoint.
- Select coal prospects which, based on available data, meet these criteria.
- Develop alternative transportation modes from supply to demand points.
- Develop the alternative supply/demand scenarios relevant to villages or regions, and assess their feasibility and practicability in light of sociostrategic and technical considerations.

This report is the result of the Phase 2 analysis. Phase 1 results are contained in a separate volume.

ECONOMIC ASSUMPTIONS

In this analysis, annual capital charges and operating costs have been estimated in 1981 dollars to allow comparison of three scenarios and their subscenarios. Component costs that have been built into this analysis are

based on readily available reference material and provide order of magnitude estimates. These component costs include those to own and operate a mine, to transport coal, and to install, own and operate generating plants. While profit is also built into the analysis, potential royalties and taxes are not included. Hard engineering costing would be required to develop cost estimates with sufficient back-up to demonstrate true real world feasibility.

The analysis relies on Alaska Power Authority (APA) assumptions for the critical discount rate and inflation parameters:

Discount rate = 3 percent

Inflation rate = 0 percent

Petroleum fuel escalation = 3.5 percent

DESCRIPTION OF PROJECT AREA

The study area encompasses a region of more than 100,000 square miles. Topography varies and ranges from sea level along the coastline to over 4,700 feet in the DeLong Mountains. As presented in Figure 1 the area includes the communities of the Seward Peninsula and Norton Sound coast south to Unalakleet, the Kobuk River Valley, Point Hope, and Point Lay. The 23 three communities of principal interest in this study are listed in Table 1.

As is evident from Table 1, one-half of the total population of the study area resides in Kotzebue and Nome. The remaining population is fairly evenly distributed throughout the 21 other communities under consideration. Few of the communities listed in the table are interconnected by roads; none are directly linked by roads to Anchorage or Fairbanks. Air travel links virtually all of the subject communities to points outside of the study area.

TABLE 1
STUDY AREA COMMUNITIES

<u>Village</u>	<u>Population 1980</u>	<u>Percent of Study Area Population</u>
Ambler	217	2
Brevig Mission	144	1
Buckland	174	2
Deering	132	1
Elim	215	2
Golovin	118	1
Kiana	314	3
Kivalina	209	2
Kobuk	61	<1
Kotzebue	2526	24
Koyuk	160	2
Noatak	291	3
Nome	2585	24
Noorvik	532	5
Point Hope	408	4
Point Lay	51	<1
Selawik	525	5
Shaktoolik	160	2
Shishmaref	309	3
Shungnak	181	2
Teller	219	2
Unalakleet	600	6
Wales	134	1
White Mountain	98	<1
	<u>10,572</u>	<u>100</u>

1.0 IDENTIFICATION OF FUEL REQUIREMENTS AND PLANT SPECIFICATIONS

1.1 INTRODUCTION

The purpose of Task 1 was to determine the energy requirements of the villages in the study area to the year 2000 and to identify the technologies available for meeting these demands. This included:

- Review of forecasted projections of energy demand;
- Assessment of relevant coal-fired power plant and space heat technology;
- Assessment of feasible transmission line technology; and
- Review of possible non-conventional coal energy technology.

1.2 ENERGY AND THE ECONOMIC DEVELOPMENT OF NORTHWEST ALASKA

Throughout northwest Alaska there are conflicting patterns of development and cultural integrity. Recognition of the need for progressive development is constrained by the desire to maintain traditional economic and social values. The result has been a dual or mixed economy consisting of a complex capital-intensive infrastructure adapted to traditional subsistence activities.

The high cost of imported diesel fuel, the predominant energy source in the area, has undoubtedly limited growth. However, even with cheaper coal-based energy there would be little enthusiasm for the expanded industrial base usually seen by economists as the goal of development. Furthermore, transportation costs, technology costs, location, geography, climatic conditions and consumers' attitude are all inhibiting factors to potential growth.

Nome and Kotzebue do not fit this pattern. These two towns are the main fuel distribution points. An increase in the economic and wage base is likely to occur if a cost-stable source of power is introduced in these areas. Both of these communities support large populations and more commercial and governmental activities than the others.

The isolated and remote character of the area posed a number of problems in analyzing the applicability of coal energy systems. Physically, the lack of roads, long distances, and harsh climate restrict transportation options. Technologically, the small population dictates very small scale technologies, at a time of ever increasing reliance on large-scale centralized technologies. Compounding these problems were the lack of consistent and accurate village records, the difficulty in obtaining data from three school districts (REAA, Northwest Arctic, North Slope Borough) and the Bureau of Indian Affairs, and the complexity of the fuel distribution and storage system in the study area.

1.3 ENERGY DEMAND FORECAST

Energy demand requirements for each of the villages in the study area were calculated through the year 2000, based on a combination of actual data and reasonable assumptions. Baseline data on existing energy used were determined in Phase 1, Task 1. These data were obtained through contacts with State, Federal and local power supply agencies, village electric utility boards, petroleum fuel producers and distributors, and individuals in each village. In addition, literature relating to the historical operations, fuel requirements, and costs of power generation in northwest Alaska were collected and analyzed.

Projection of fuel usage over the next 20 years involved a number of simplifying assumptions, the most important of which was that energy consumption patterns would remain unchanged over the entire study period. Because of the low level of economic development in the area and the limited nature of this study, the local economy in each village was divided into three principal sectors:

- Private residences.
- Schools.
- Government and commercial users.

Population growth, as forecasted by the Alaska Department of Transportation and Public Facilities (1980), was used as the basis for projecting energy demand in the residential and educational sectors. Energy demand in the combined government and commercial sector was held essentially constant because of the limited amount of growth anticipated, except in the larger villages of Nome, Kotzebue, and Unalakleet. The diesel demand forecast shown in Table 1-1 was then created by summing projected consumption in each of the three identified sectors.

No reliable records exist for electric generation. Therefore, it was necessary to use existing and projected diesel consumption to estimate the quantity of local coal necessary to replace the imported diesel oil currently used for generating electricity and/or providing space heat. The conversion from diesel-electric generation to coal-electric generation was accomplished by first calculating the effective number of Btu's generated by diesel oil in small local generators, and then "working backwards" to calculate the amount of coal necessary to provide an equivalent amount of electricity. This process is illustrated in equations 1 and 2:

$$(Eq. 1) \quad \text{Gallons} \times \text{Btu/Gal.} \times \text{Conversion Efficiency} = \text{Btu}_e$$

$$\begin{aligned} \text{Where: Btu/Gal.} &= 130,952 \\ \text{Conversion Efficiency} &= 18.6\%(1) \end{aligned}$$

$$(Eq. 2) \quad \text{Btu}_e / \left(\frac{\text{Btu}}{\text{lb}} \times \frac{\text{lbs}}{\text{ton}} \times \text{Conversion Efficiency} \right) = \text{Tons Coal}$$

$$\begin{aligned} \text{Where: Btu/lb} &= 10,000(2) \\ \text{lbs/ton} &= 2,000 \\ \text{Conversion Efficiency} &= 25\% \end{aligned}$$

(1) Fryer-Pressley-Elliott, 1980

(2) This is an average value for bituminous coal. Where lower heat value coal is mined, the bottomline cost per ton will be adjusted to reflect the greater amount of coal needed.

TABLE 1-1

DEMAND FORECAST OF ENERGY REQUIREMENTS BY COMMUNITY
IN GALLONS 1980-2000

Village	Population	Space Heating Demand ⁽³⁾ (Gallons of Diesel) in Year					Electricity Demand ⁽⁴⁾ (Gallons of Diesel) in Year				
		1980	1985	1990	1995	2000	1980	1985	1990	1995	2000
Ambler	217	66,408	69,608	72,008	74,408	77,008	28,360	29,300	30,006	30,712	31,476
Brevig Missior ⁽²⁾	144	43,134	44,234	46,434	46,434	47,534	23,360	23,713	24,183	24,419	24,654
Buckland	174	45,585	46,585	46,385	50,385	52,385	36,634	36,928	37,457	38,045	38,633
Deering	140	27,000	--	--	--	29,455	45,000	--	--	--	49,091
Elim ⁽²⁾	215	54,149	57,349	59,549	60,749	62,149	24,151	25,091	25,738	26,091	26,503
Golovin	118	37,859	39,859	41,059	41,659	42,459	21,556	22,144	22,497	22,674	22,909
Kiana	314	102,029	106,629	110,029	113,629	117,429	34,063	35,415	36,415	37,474	38,590
Kivalina	209	70,600	82,400	85,200	88,000	91,000	27,889	31,358	32,182	33,005	33,887
Kobuk	61	24,350	25,150	25,950	26,550	27,350	8,431	8,666	8,901	9,078	9,313
Kotzebue ⁽¹⁾	2,526	1,800,000	1,894,800	1,933,200	1,974,200	2,017,600	1,200,000	1,227,871	1,239,161	1,251,215	1,263,975
Koyuk ⁽²⁾	160	57,500	59,100	60,500	61,900	63,300	23,668	24,138	24,550	24,962	25,373
Noatak	291	88,200	90,000	93,200	96,400	99,800	32,711	33,240	34,181	35,122	36,121
Nome ⁽¹⁾	2,585	1,240,000	1,351,800	1,397,000	1,414,200	1,438,600	1,000,000	1,032,869	1,044,218	1,051,215	1,058,388
Noorvik	532	175,390	182,990	188,790	194,990	201,390	46,881	49,116	50,821	52,644	54,525
Point Hope	408	141,600	147,400	152,400	157,600	163,000	53,990	55,696	57,165	58,694	60,282
Point Lay	51	40,200	42,400	43,000	43,800	44,600	18,599	19,246	19,422	19,657	19,892
Selawik	525	182,712	191,112	196,912	202,912	209,312	46,470	48,940	50,645	52,409	54,290
Shaktoolik ⁽²⁾	160	51,200	57,800	59,800	60,800	61,800	30,458	32,986	32,986	33,280	33,574
Shishmaref	309	103,800	117,600	121,600	123,600	125,600	38,769	42,826	44,002	44,590	45,178
Shungnak ⁽²⁾	181	66,620	76,620	78,820	81,420	84,020	26,243	29,183	29,830	30,594	31,358
Teller ⁽²⁾	219	78,420	81,820	84,220	85,420	86,820	44,303	45,303	46,008	46,361	46,773
Unalakleet ⁽¹⁾	600	295,000	312,400	320,800	324,600	328,400	180,518	185,634	188,103	189,220	190,338
Wales	134	56,800	57,800	59,200	60,000	60,800	20,479	20,773	21,185	21,420	21,665
White Mountain ⁽²⁾	98	38,600	43,600	45,000	45,600	46,200	15,762	17,232	17,644	17,820	17,997

(1) Includes Commercial Sector

(2) Major user of wood for home heating

(3) Projects space heating needs now served by diesel only (not wood or electricity)

(4) Projects existing uses of electricity as increased by population growth and expansion of use in commercial and governmental sectors.

Source: Dames & Moore, 1980.

Personal Communication with Roy Barkwell (Fryer-Pressley-Elliott), 1981.

Department of Transportation and Public Facilities, 1980.

Personal Communication with Mark A. Newell (Wind Systems Engineering, Inc.), 1981.

Personal Communication with Ron Wesley (Northwest Arctic School District), 1981.

Similarly, the conversion from diesel furnace space heating requirements to coal furnace space heating requirements involved calculating the effective amount of heat produced by local diesel consumption, and then calculating the quantity of coal necessary to generate it. This method is more accurate than using data on the theoretical energy consumption of a home of a given size, since actual local use conditions are reflected in the diesel consumption. The equations used for this conversion differ from the electrical generation conversion equations only in the efficiency factor: in this case, the efficiency of producing warm air through direct combustion was assumed to be approximately the same for either fuel, or 50 percent.

Forecasts of coal demand by village for the year 2000 are given in Table 1-2.

1.4 COAL-FIRED ELECTRIC POWER PLANT AND SPACE HEATING TECHNICAL REQUIREMENTS

Villages in northwest Alaska currently derive most of their energy from two sources: diesel oil in electric generators and home heating, and wood for direct combustion heating. Electrical power in each village is typically supplied by two 55-KW diesel generators. They are relatively inefficient (Fryer-Pressley-Elliott, 1980) and expensive to operate, due to the excessive cost of importing diesel oil into the area (an average of \$1.50 per gallon). Residential heating is similarly costly. Most homes use a combination of oil-fired furnaces and wood stoves to generate heat, with the wood stove operating at night and the oil-fired furnace set to come on in the morning.

The following elements were suggested by Mechanical Technology Incorporated as necessary for successful construction and operation of a small coal-fired power plant under arctic conditions:

- The complete system should have high reliability of operation;
- Electric power output should be at a stable frequency and voltage;

TABLE 1-2
COAL DEMAND FORECAST BY VILLAGE, YEAR 2000
(IN TONS)

Village	(1) Direct Heating Demand	(2) Electrical Demand		(3) Electrical + 10% Elec. Heat		(4) 90% of Direct Heating Demand
		Tons	Million KWH	Tons	Million KWH	Tons
Ambler	504	153	.22	265	.39	453
Brevig Mission	311	120	.18	189	.28	279
Buckland	343	188	.28	267	.39	309
Deering	192	239	.35	282	.41	173
Elim	407	129	.19	219	.32	366
Golovin	278	112	.16	174	.25	250
Kiana	769	188	.28	296	.43	692
Kivalina	596	165	.24	298	.44	536
Kobuk	179	45	.07	86	.13	161
Kotzebue	13,210	6,157	9.02	9,091	13.32	11,889
Koyuk	414	124	.18	216	.32	372
Naotak	653	176	.26	321	.47	646
Nome	9,419	5,156	7.53	7,249	10.62	8,477
Noorvik	1,319	266	.39	559	.82	1,187
Point Hope	1,067	294	.43	532	.78	960
Pont Lay	292	97	.14	162	.24	263
Selawik	1,370	264	.39	569	.83	1,233
Shaktoolik	405	164	.24	254	.37	365
Shishmaref	822	220	.32	403	.59	740
Shungnak	550	153	.22	275	.40	495
Teller	568	228	.33	354	.52	511
Unalakleet	2,150	927	1.36	1,405	2.06	1,935
Wales	398	105	.15	194	.28	358
White Mountain	302	88	.13	155	.23	272
	36,518	15,758	23.09	23,874	34.97	32,869

Source: Dames & Moore

- (1) Coal equivalent of diesel fuel for space heating.
- (2) Coal required to deliver projected demand (derived from existing demand).
- (3) Coal required to deliver projected demand (derived from existing demand) plus 10 percent of the space heating demand, electrically.
- (4) Coal required to deliver direct space heat for 90 percent of the total space heat demand.

- Design should call for low maintenance, stressing simplicity of operation and preferably capable of being serviced by local semi-skilled labor;
- Redundancy of support and subsystems should be provided to assure maximum electric generation reliability; and
- Noise levels should be compatible with those considered acceptable by people living in the arctic villages.

These criteria focus on developing a simple power plant using a minimum of components, and automated equipment that would not require highly skilled service personnel or delicate control equipment. Every effort should be made to avoid seals, heavy assemblies, and auxiliary devices that are subject to frequent inspection and repair. The basic system configuration would include three main modules (boiler package, expander generator, and condenser package) packaged for minimum field assembly. They would be integrated to form a complete power unit in a total volume that would provide adequate room for servicing and only require a simple, easily fabricated and heated weather-tight building. This prefabricated building would house the major equipment with adequate room for servicing and equipment laydown during disassembly.

One common problem in attempting to utilize these plants involves the basic technological sophistication and maintenance cost of even simple coal-fired electric steam generators. Given the climatic and geographic characteristics of northwest Alaska, these costs are very high.

A second common problem is related to transmission line distance and the consequent distribution cost for all units other than small, local "suitcase" plants. Although economies of scale exist for the larger regional plants, the problems of transmission distance, personnel requirements, and equipment costs tend to offset these cost savings. These factors are examined in some detail under Chapter 4.0.

When considering siting and technical problems for a small coal-fired electric steam generator, efficiency is an important consideration. Stoker-sized coal (1 1/2 inches or less) containing a 12 percent moisture and 12 percent ash content and rated between 10,000 to 12,000 Btu/lb is recommended. Lower quality coal may be substituted if necessary at a cost in efficiency (Cliff Goodby, Cole, Inc., personal communication, 1980). It is generally acknowledged that the final efficiency ratings for a small coal-fired boiler/generator/turbine combination is in the 30 to 40 percent range under ideal conditions. For this study, efficiency was assumed to average 25 percent based on the small size of units and unfavorable environmental conditions.

The environmental and ecological aspects of the area (including impacts on air and water quality, terrain disturbance, land ownership, and impacts to fish and wildlife) are other considerations in siting. Although these were considered in our analysis, no breakdown of site-specific constraints or the cost of mitigative measures was undertaken. In addition to considerations of the environment during siting, it is necessary to determine the availability of water, and of coal storage facilities. Water demands were assumed attainable through river bank plant siting. Coal storage facilities may be necessary because under extremely cold conditions coal freezes and becomes difficult to work with. Given the uncertainty and variability of the possible sites for storage; however, this factor was excluded from the analysis contained in Chapter 4.0. Because this document represents primarily a regional economic analysis, we have assumed a public acceptance of conversion from fuel oil to coal.

Table 1-3 illustrates representative power plant costs needed to bring various plants into operation. Included are the costs of storage, handling equipment, boilers, turbines, yards, and pollution equipment. Not included are the costs of power transmission and maintenance costs, and costs associated with environmental impact assessments and mitigative measures.

Economies of scale are pronounced in power generation. Doubling the size of the plant does not nearly double investment or operating costs. These inherent economies of scale have lead to increasing centralization of

TABLE 1-3
ESTIMATED POWER PLANT COSTS

Size (MW)	Cost per Installed Kilowatt (\$)	Total In-Place Initial Capital Investment (\$1,000,000)	Annual Ownership Costs ⁽⁴⁾ (\$1,000)	Annual Operating Cost (\$1,000)	Total Annual Cost (\$1,000)
0.1-0.5	(1)	3.5	179	200	379
1.0	4,000	4.0	204	200	404
5.0	3,500	17.5	893	400	1,293
10.0	2,800 ⁽²⁾	28	1,428	500	1,928
25.0	2,800 ⁽³⁾	70	3,571	800	4,371

(1) Since even these very small size power plants would require the same handling and combustion equipment as 1 MW units, the total cost is not proportion to size but is only slightly lower than the 1 MW units.

(2) This cost per KWH is based on a 10 MW unit designed for Kotzebue (APA, Brent Petrie, 11/3/81).

(3) No further reduction in cost per KW is assumed between 10 and 25 MW because added costs for pollution control equipment are assumed to cancel out economies of scale.

(4) Assumes an annual capital recovery factor of 0.05102 (see Section 4.3.2).

generating capacities in most of the Lower 48. Rather, it is the cost of transmitting power that drives up the price of electricity in northwest Alaska.

1.5 TRANSMISSION LINE ALTERNATIVES AND COSTS

Electric power can be transmitted in a variety of forms: DC or AC; single-wire ground return or three-wire one phase or three phase; overhead, submarine, or buried lines. Based on consideration of the advantages and disadvantages of each system, conventional three-wire, three-phase overhead AC lines appear preferable. (Details on the characteristics of each transmission system are given in Appendix I.)

Cost estimates for transmission lines were obtained by contacting electrical utilities in Alaska and in mountainous areas of the Lower 48. On the basis of these contacts, installation of 69 KV overhead AC lines would cost roughly \$150,000 per mile in rolling hills and river valleys (such as the Kobuk River Valley) for an annual ownership cost of \$7,320 over 20 years. Annual maintenance would cost roughly \$10,000 per mile. A levelized total annual cost would thus be approximately \$17,320 per mile. As will be shown in Chapter 4.0, the high cost of transmitting power swamps the economies of scale in power generation.

1.6 NON-CONVENTIONAL COAL ENERGY TECHNICAL REQUIREMENTS

Coal liquefaction is a high technology application. Gasification may be either a high technology or a low (but sophisticated) one. High technology applications are probably impractical for remote areas such as northwest Alaska in the absence of highly skilled operators and ready access to replacement parts.

Low technology gasification is a distinct possibility on the individual community level. This possibility is currently being explored by Donald Fiscus, plant manager of Kotzebue Electric Association. At this time, however, gasification is still in the experimental stage in application to northwest Alaska. No firm costs or turn-key plants are presently available.

Thus, for the purpose of this study, coal gasification will not be considered further, despite the possibility that in the future it may prove a viable option.

1.7 SPACE HEATING TECHNOLOGY

Most homes in the study area are probably heated by a combination of oil (diesel) furnaces and wood stoves. If coal were available at a competitive price, diesel use would likely decline. Space heating in homes might be accomplished by a combination of direct burning of coal and electricity. Coal can be burned in some stoves that now burn wood, such as potbelly stoves. In general, the national demand for wood stoves over the past few years has resulted in the development of a greater selection of high-efficiency stoves. Many burn wood or coal, and are commonly available in Alaska for about \$1,000. These stoves would be very appropriate for the study area. For this study, a heating efficiency of 50 percent is assumed for coal stoves, although even higher efficiencies are often claimed.

Electric space heat can be accomplished by radiant heaters, resistance heaters, and heat pumps. Heat pumps perform very poorly at low ambient temperatures and are thus totally inappropriate for the area. Resistance heaters have very high heating efficiencies (in excess of 90 percent), but this is only after 75 percent of the heat value of the coal has been lost during conversion to electricity. Recently, quartz radiant heaters have become available. These heaters (which cost \$50 to \$75) have the same nominal efficiency as resistance heaters. However, since they are primarily a radiant source their energy heats people and objects rather than air. These radiant units would be very effective in the drafty, poorly insulated houses common in the study area.

2.0 IDENTIFICATION OF SUITABLE COAL OCCURRENCES FOR EXPLOITATION

2.1 INTRODUCTION

The principal objectives of Task 2 were to:

- Establish the coal occurrences identified in Phase I that appear qualitatively and quantitatively suitable for coal-fired generating plants or in space heating applications;
- Determine which of the candidate coal occurrences are sufficiently close to end-use demand centers to enable their exploitation; and
- Develop hypothetical mining plans and establish associated development and exploitation costs for the candidate coal deposits.

Phase I of this study surveyed the available information about coal occurrences in the study area. In this chapter we combine information from Phase I with the projections of coal demand to assess the most likely prospects for coal development and to estimate the cost of mining coal at the indicated scale.

2.2 CRITERIA FOR SELECTION OF COAL OCCURRENCES

The first two objectives can be distilled into the following criteria for judging the suitability of a given coal occurrence:

1. Quality: The heat value of coal (coal "rank") should be adequate for power generation.
2. Quantity: Sufficient reserves for meeting the projected demand must be present.
3. Proximity: Coal must be within a feasible transportation distance from its point of use.

Quality: Ideally, the heat value of a pound of coal should be at least 10,000 Btu for power generation. Lower rank coals such as lignites burn slightly less efficiently, produce more ash and are more costly to transport (since more coal must be moved for a given amount of heat).

Quantity: Since few of the coal occurrences in northwest Alaska have been geologically mapped and sampled in any detail, most estimates of particular occurrences are largely unsubstantiated and should be considered as an approximate indication of the quantity and quality of the deposit. Therefore, to establish the quantitative suitability of a given coal occurrence, assumptions were made about the extent of the coal occurrence, on a case-by-case basis, using both the limited data available as well as professional judgment. Coal occurrences with insufficient information were eliminated from further consideration as a potential source of supply.

Proximity: In addition to the two basic qualitative and quantitative requirements, the best coal occurrences were also considered from a geographic standpoint, according to:

- Distance from a potential demand center,
- The existence of a potentially suitable transportation route or mode of transport.

Table 2-1 summarizes the information on coal occurrences near each community and ranks their suitability on the basis of the above criteria. The coal source areas are identified by a number that corresponds to a location on Figure 2-1. Distance, transport mode, and favorable and unfavorable factors are discussed for each selected source area.

For example, it has been determined that Nome could be supplied with coal from three local sources (see Table 2-1): Kuzitrin Basin, McCarthy's Marsh, and Unalakleet. Although each of these occurrences is reported to be lignite, the Kuzitrin Basin deposit is somewhat more desirable than its competitors. This is due to:

TABLE 2-1
SELECTION OF AREAS TO SUPPLY COAL TO COMMUNITIES

<u>Community</u>	<u>Community Suitability Ranking</u>	<u>Possible Coal Source Areas</u>	<u>Coal Rank</u>	<u>Direct Distance Miles</u>	<u>If Community On Coast Distance of Source To Coast (Miles)</u>	<u>Possible Modes Of Transportation</u>	<u>Favorable Factors</u>	<u>Unfavorable Factors</u>
Ambler	1	14	?	5-23		Land	Near village	Unconfirmed occurrence Small potential
Brevig Mission	1	24	Lignite	65	40	Land, Land-Sea	Known occurrence Nearest potential coal field Medium potential	Long transportation distance
Buckland	1	18	Lignite	36		Land	Well known occurrence Thick seam Medium potential	90 miles travel Steep dips and faults
Deering	1	18	Lignite	15		Land	Well known occurrence Thick seam Medium potential	
Elim	1	22	Lignite- Subbituminous	18-40	18-40	Land	Nearest coal field Medium/large potential	
	2	19	Lignite	18-30		Land	Medium potential Near village	Overland travel
Golovin	1	23	Lignite	45	62	Land	Large potential Nearest coal field	Limited information

TABLE 2-1 (continued)

<u>Community</u>	<u>Community Suitability Ranking</u>	<u>Possible Coal Source Areas</u>	<u>Coal Rank</u>	<u>Direct Distance Miles</u>	<u>If Community On Coast Distance of Source To Coast (Miles)</u>	<u>Possible Modes Of Transportation</u>	<u>Favorable Factors</u>	<u>Unfavorable Factors</u>
Kiana	1	12	Bituminous	16		Land	Nearest known coal field Near village Known coal-bearing beds Readily accessible	Small potential
Kivalina	1	10	Semianthracite	56	8	Land-Sea	Good quality Thick seam Shallow depth Medium potential Nearest resource	
Kobuk	1	14	?	5		Land	Near village	Unconfirmed occurrence Small potential
Kotzebue	1	18	Lignite	70	9	Land-Sea	Well known occurrence Thick seam Medium potential	Steep dip and faults Long transportation distance
	2	12	Bituminous	73	50	Land-Sea		Long transportation distance
	3	10	Semianthracite	140	8	Land-Sea	Good quality Main sea transport Medium potential	Long transportation distance

TABLE 2-1 (continued)

Community	Community Suitability Ranking	Possible Coal Source Areas	Coal Rank	Direct Distance Miles	If Community On Coast Distance of Source To Coast (Miles)	Possible Modes Of Transportation	Favorable Factors	Unfavorable Factors
Koyuk	1	26	Lignite	2		Sea	Near village	Small potential
Noatak	1	10	Semianthracite	96		Land, Sea-Land	Good quality Thick seam Shallow depth Medium potential	Long transportation distance
	2	12	Bituminous	91		Land	Nearest known coal field	Long transportation distance Small potential
Nome	1	24	Lignite	76	40	Land	Medium potential	Long transportation distance
	2	23	Lignite	90	62	Land, Land-Sea	Large potential	Limited information Long transportation distance
	3	27	Lignite	150	2	Land-Sea	Near coast Medium potential	Long transportation distance
Noorvik	1	12	Bituminous	34		Land	Nearest known coal field Known coal-bearing beds Readily accessible	Small potential

TABLE 2-1 (continued)

<u>Community</u>	<u>Community Suitability Ranking</u>	<u>Possible Coal Source Areas</u>	<u>Coal Rank</u>	<u>Direct Distance Miles</u>	<u>If Community On Coast Distance of Source To Coast (Miles)</u>	<u>Possible Modes Of Transportation</u>	<u>Favorable Factors</u>	<u>Unfavorable Factors</u>
Point Hope	1	10	Semianthracite	22	8	Land, Land-Sea	Good quality Near village Thick seam Shallow depth Medium potential	
	2	9	Bituminous	30	0	Sea	On coast in cliffs Limited information Small potential	Possibly U/G mining
	3	9	Bituminous	25	0	Sea	Medium potential On coast in cliffs	Tectonically complex Probable U/G mining
	4	1	Bituminous	15	15	Land	Near village	Location not confirmed

TABLE 2-1 (continued)

<u>Community</u>	<u>Community Suitability Ranking</u>	<u>Possible Coal Source Areas</u>	<u>Coal Rank</u>	<u>Direct Distance Miles</u>	<u>If Community On Coast Distance of Source To Coast (Miles)</u>	<u>Possible Modes Of Transportation</u>	<u>Favorable Factors</u>	<u>Unfavorable Factors</u>
Point Lay	1	2	Bituminous	12-32	6-12	Land, Land-Sea	Very large potential Near coast Near village	
	2	1	Bituminous	10	3	Land, Land-Sea	Medium potential Near coast Near village	
	3	6	Bituminous	40	4	Land-Sea	Very large potential Shallow dip Near coast	
	4	7	Bituminous	55	0-6	Land-Sea	Very large potential Near coast	Relatively high ash
	5	8	Bituminous	80	0	Sea	On coast Large potential	Long transportation distance Probable U/G mining in cliffs
Selawik	1	12	Bituminous	32	50	Land, Land-Sea	Near village Known coal-bearing beds Readily accessible	Small potential

TABLE 2-1 (continued)

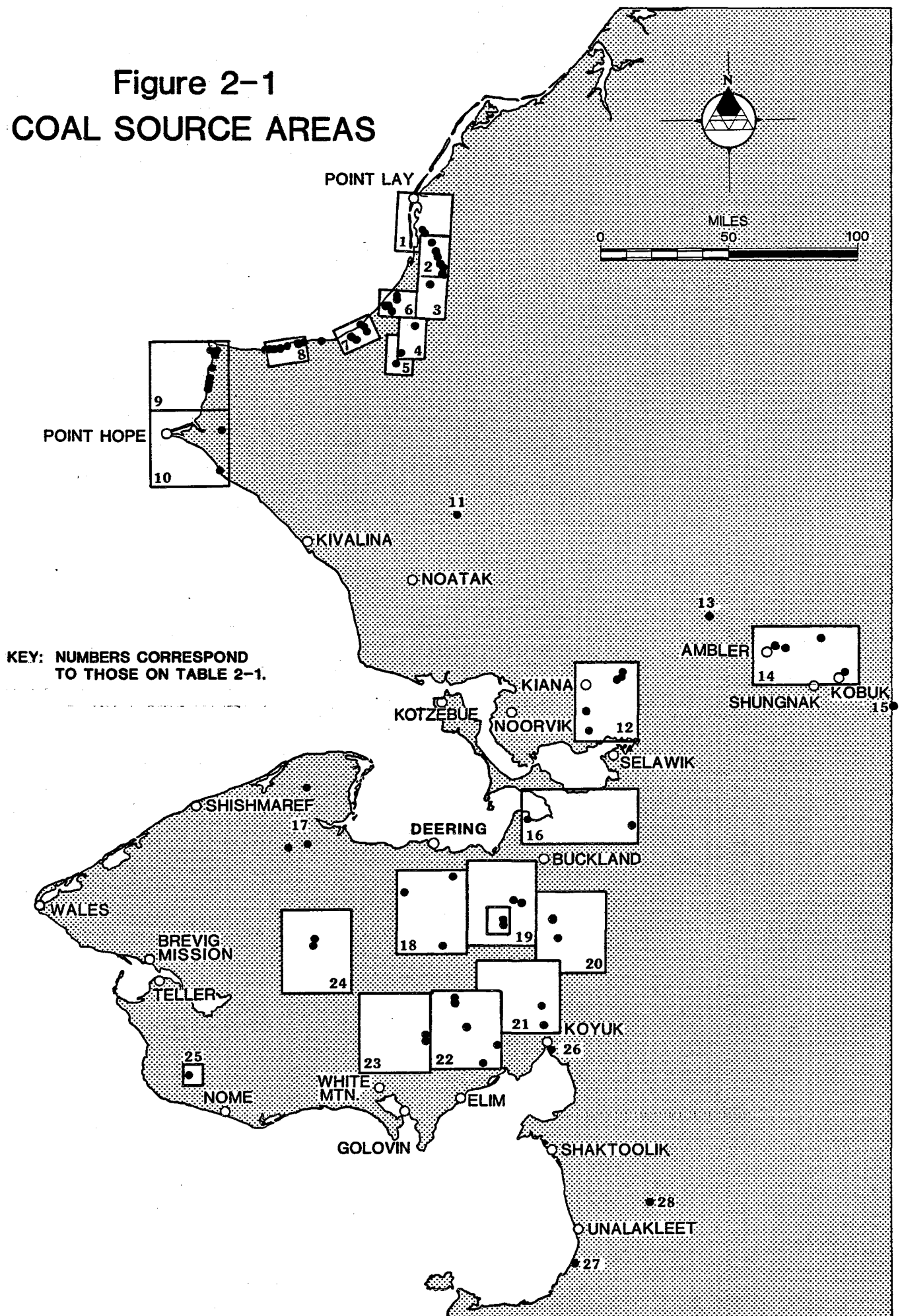
Community	Community Suitability Ranking	Possible Coal Source Areas	Coal Rank	Direct Distance Miles	If Community On Coast Distance of Source To Coast (Miles)	Possible Modes Of Transportation	Favorable Factors	Unfavorable Factors
Shaktoolik	1	27	Lignite	46	2	Land-Sea	Nearest coal field Medium potential	
Shismaref	1	10	Semianthracite	150	8	Land-Sea	Good quality Thick seam Medium potential Shallow depth Mainly sea transport	Transportation 170 miles
	2	18	Lignite	106	9	Land-Sea	Well known occurrence Thick seam Medium potential	Transportation distance 140 miles Steep dips and faults
	3	17	Lignite	0-65	?	?	Nearest potential coal field Large potential	Coal known in float and one oil well only
Shungnak	1	14	?	14		Land	Near village	Unconfirmed occurrence Small potential

TABLE 2-1 (continued)

<u>Community</u>	<u>Community Suitability Ranking</u>	<u>Possible Coal Source Areas</u>	<u>Coal Rank</u>	<u>Direct Distance Miles</u>	<u>If Community On Coast Distance of Source To Coast (Miles)</u>	<u>Possible Modes Of Transportation</u>	<u>Favorable Factors</u>	<u>Unfavorable Factors</u>
Teller	1	24	Lignite	62	40	Land, Land-Sea	Known occurrence Nearest potential coal field Medium potential	Long transportation distance
Unalakleet	1	27	Lignite	13	2	Land-Sea	Near village Medium potential	
Wales	1	24	Lignite	110	40	Land, Land-Sea	Known occurrence Medium potential	Long transportation distance
	2	10	Semianthracite	200	8	Land-Sea	Good quality Thick seam Medium potential Shallow depth	Transportation distance
White Mountain	1	23	Lignite	40		Land	Large potential Nearest coal field	Limited information
	2	21	Lignite	9-16	9-16	Land	Large potential Near village	Limited information

Source: Dames & Moore, 1980

Figure 2-1
COAL SOURCE AREAS



- The shorter distance between the Kuzitrin Basin deposit and Nome;
- The requirement for only one transportation mode to bring the coal from the Kuzitrin Basin to Nome; and
- The greater availability of data concerning the qualitative and quantitative aspects of this deposit.

2.3 DEVELOPMENT OF MINING CONCEPTS

Inasmuch as very little data are available concerning the geologic setting of most of the coal deposits in northwest Alaska, the development of a definite mining plan on a site-specific basis and an estimate of associated production costs is difficult. Therefore, several general mine models were developed to estimate the mining costs for the various types of coal occurrences known or likely to occur in northwest Alaska. For each of the rates of production, the operating and capital costs per ton of coal mined were developed for both open pit and underground operations.

The mining concepts are described as six separate models for both underground and surface operations. The models have been selected in light of the possible production rates required and geologic conditions likely to be encountered in the study area. For each model, the benefits and liabilities attached to the mining method are discussed in Appendix II, along with a discussion of operation.

The following is a summary of the mining concepts modeled:

Model 1: Assumes a production capacity of 100 tons annually over a 25-year period. The minimum extractable coal reserve required to sustain such an operation would be 2,500 tons.

Model 2: Assumes a production capacity of 500 tons annually over a 25-year period. The minimum extractable coal reserve required to sustain such an operation would be 12,500 tons.

Model 3: Assumes a production capacity of 1000 tons annually over a 25-year period. The minimum extractable coal reserve required to sustain such an operation would be 25,000 tons.

Model 4: Assumes a production capacity of 5000 tons annually over a 25-year period. The minimum extractable coal reserve required to sustain such an operation would be 125,000 tons.

Model 5: Assumes a production capacity of 10,000 tons of coal annually over a 25-year period. The minimum extractable coal reserve required to sustain such an operation would be 250,000 tons.

Model 6: Assumes a production capacity of 60,000 tons of coal annually over a 25-year period. The minimum extractable coal reserve required to sustain such an operation would be 1.5 million tons.

2.3.1 Conditions Influencing Mining Concept Formulation

In formulating mining concepts for the conditions found in the study area, consideration must be given to geology, organization and management, local and regional socioeconomic conditions, climate, ground conditions, beneficiation, and regulations.

Geology: Owing to the vast area covered and lack of detailed geological data, exploitable coal reserves for the purpose of this study are anticipated to be established in areas where the coal outcrops at the surface or where definite coal deposits have been identified. Throughout this study, the assumed thermal content of coal is 10,000 Btu per pound. This is despite the fact that coal in the study area is known to range from anthracite (13,500 Btu/lb) to lignite (6,500 Btu/lb). When anthracite is being mined, less tonnage will be required; conversely, when lignite is being mined, more tonnage will be required to obtain the equivalent Btu value. However, given the paucity of geologic data (both quantitative and qualitative) of the coal occurrences in the study area, this factor was not taken into account in determining tonnage requirements.

- There would be expense and time for preparing environmental impact statements and obtaining permits prior to mining.
- Measures to be taken during mining to preserve the environment could add considerably to the cost of mining.

These matters should be investigated before any large capital expenditures are committed to determine if these added costs would render any such mining project uneconomic.

Organization and Management: Apart from the technical and economic aspects of mining coal in northwest Alaska, some thought should be given at this stage to the subject of organization and management. This is especially true in the case of mines of the size required to supply several villages.

One of the problems inherent in such small-scale mining could be maintaining manpower at the required technical and craft levels to ensure a reasonably efficient operation. In the case of small-scale surface mining, once mining has commenced very little engineering expertise would be required to maintain an efficient operation. However, competent craftsmen would be required to service and maintain the equipment.

In the case of small-scale underground mining, the staff would need to include personnel of such caliber and experience as to ensure that all health and safety regulations are adhered to in maintaining a safe operation. As with surface mining, competent craftsmen would be required to service and maintain the equipment.

In the case of a mine supplying a regional power plant, the mine would be of such a size as to establish a small community, which should attract and maintain a reasonably stable staff and labor force.

Local and Regional Socioeconomic Conditions: Consideration should also be given to the compatibility of the mining concept with local and regional socioeconomic conditions. These conditions would include:

- Number of local residents to be employed.
- Size of imported labor force.
- Land use values.
- Effects on continuation of rural cooperatives.
- Extent of any required government subsidy.

Climate: Mining operations in northwest Alaska will be affected by the severe climate and the remoteness of the region from supply centers. In some areas, economically feasible access to a mining site may be possible only in the winter when the ground is frozen. In other areas, access will be limited to the summer months when roads are free of snow. Because transportation of the coal may likewise be restricted to one season -- particularly if barging is required -- seasonal stockpiling of coal may be required at the point of production and/or the demand center.

Weathering along the outcrops of the coal seams will probably be less than that observed in warmer climates. Therefore, for the purposes of this study it has been assumed that there is no appreciable weathered zone.

Ground Conditions: Permafrost occurs throughout the project area. Before discussing the relative merits of surface and underground mining, and the problems associated with each type of mining, several factors related to mining in permafrost areas should be considered. These factors include roof support ventilation, and constraints associated with frozen water. A study completed by the Mineral Industry Research Laboratory at the University of Alaska (Lynch et al., 1976) addresses these factors. Excerpts are included in Appendix III. This information was incorporated in the mining conceptualization.

Benefication of Coal: No consideration has been given to the possibility of coal benefication (cleaning or sizing) of mine run material. Any wet process would of course be impractical in an area experiencing freezing temperatures for most of the year. The mining system should produce as clean a coal product as possible and any unavoidable dilution should be well blended and accepted in the power plant feed. It has been assumed that only

crushing to roughly 4 to 6 inches would be carried out at the mine site, and that any other preparation would be carried out at the power station.

Regulations: No consideration has been given in this study to the possible effects of federal and state regulations on mining in the study area. These regulations create the following considerations:

In the case of mines for village-sized power plants, consideration should be given to establishing a centrally located control management team that would tour the mines on a regular basis. This management team would provide required technical expertise and would organize the transport of regular and emergency supplies, and of coal to the power station.

Some consideration should also be given to providing incentives to maximize productivity and efficiency while minimizing costs. Such incentives could be provided by having the mining carried out by a contractor, whereby the minimizing of costs maximizes profits. Such a system would be difficult to implement in the type of situation envisaged, however, because of the difficulty in forecasting productivities and costs. This system as well as other incentive systems should, however, be considered.

2.3.2 Advantages and Disadvantages of Surface and Underground Mining

The advantages and disadvantages in each case of mining by surface and underground methods are summarized below:

Surface Mining

Advantages:

- Higher mining recovery; therefore, a smaller area of coal would be required for a given seam thickness. Additionally, exploration expenditure would be reduced given this factor.
- Little operating and/or mining skill experience would be required beyond knowledge of operating construction type equipment.
- Mining would start at the outcrop; therefore, little development work would be required.

Disadvantages:

- The operation would be exposed to the weather and, therefore, low efficiency and high maintenance would be experienced in the winter months.
- Diesel fuel would be required to power the mobile equipment. Consequently, the importation of this fuel would incur the same problems as the present supply to villages. This would be a problem particularly if the mine is inland.
- There would be greater disruption of terrain and thus greater potential reclamation costs.

Underground Mining

Advantages:

- The mining area working faces would not be exposed to the weather. Thus, efficiencies in labor would likely be attained.
- Except in the first section of the ventilation intake airway, permafrost would assist in maintaining roof support.
- The mine could be essentially all electric (rather than diesel); the electricity being produced by a small coal-fired generator similar to those proposed for the villages. A small diesel generator could be kept as a backup system for emergency heat and light.

Disadvantages:

- Lower mining recovery; therefore, a greater area of coal would be required for a given seam thickness. Exploration expenditures would likely be greater than for an open-pit operation.
- Some technical skill and experience would be required in operating the mine.
- Dust suppression by water is not practical in permafrost ground.

2.4 SELECTION OF SUITABLE OCCURRENCES AND APPLICABILITY OF MINING CONCEPTS

In selecting coal occurrences from the larger set appearing in Table 2-1, the criteria for selection (Section 2.2) were applied in light of the

considerations related to mining concepts. Some areas were eliminated due to transportation difficulties while others were eliminated because they would require underground mining.

The preferred occurrences were selected for the following reasons:

- Point Lay and Cape Beaufort occurrences were chosen because they have significant probable reserves of coal of at least bituminous rank and are located close to the coast.
- Kallarichuk was chosen as the best site near Kiana that is surface mineable.
- Ambler River deposits were chosen for its bituminous rank, proximity to Ambler, and surface mineability.
- Chicago Creek was chosen despite its low rank (lignite) and because of its known reserves and proximity to Kotzebue.

Table 2-2 briefly describes those occurrences judged to be suitable for exploitation, and indicates which mining model would be applicable to them.

Determining the applicability of the mining concepts to the possible coal source areas is very much a judgment based on the limited available geologic information. The applicability of the concepts does not necessarily imply good potential in any area. On the contrary, some areas where one of the conceptual mine models may have been suggested as applicable may, in fact, turn out to have poor potential if more data were available. Other areas where no conceptual mine models have been suggested as applicable may have good potential if more data were known. Where no conceptual mine models have been suggested as applicable, surface mining is assumed to be the most likely mining method. This holds true especially where the required coal reserve is small, by virtue of the fact that mining along the outcrop to a shallow depth is all that may be required to achieve the required coal output and reserve. Table 2-2 summarizes the applicability of the conceptual mine models to the possible coal source areas.

TABLE 2-2
APPLICABILITY OF MINE CONCEPTS

<u>Possible Coal Source Area</u>	<u>Description</u>
<u>Point Lay (Area 1A)</u>	Two coal beds have been noted. One 5-foot bed was sampled near the synclinal axis. No strike length or dip, or even the exact location are reported, and no mine concepts can be suggested, given the paucity of information.
<u>Point Lay (Area 1B)</u>	With reported seam thicknesses of 2.5, 7, and 7 to 8 feet and dips of 30° to 40°, this deposit is similar to the conceptual surface mine Model 5 configuration. Though no strike lengths are reported, indicated reserves of 1 million tons and inferred reserves of 2 million are suggested.
<u>Point Lay (Area 2A)</u>	Nine coal beds more than one foot thick have been observed. Dips ranging from 6° to 10° in one location, to 40° in another have been observed. In a seven mile interval, one 7-foot bed, one 5-foot bed, two 4-foot beds, and two 3-foot beds occur.
<u>Point Lay (Area 2A)</u>	The relationship of these beds to each other is not reported, but the deposit is most similar to the conceptual surface mine Model 6 configuration. Coal resources are estimated to be 63 million tons indicated and 219 million tons inferred.
<u>Point Lay (Area 2B)</u>	Eight coal beds more than one foot thick have been observed. Dips of 17° to 20° are recorded off the flank of an anticline compared to 5° to 10° off a syncline. Beds of 2.6, 2.9, 3 (2 of), 5 and 7(2 of) feet thickness have been found at different locations. Conceptual surface mine Model 5 appears to best fit this deposit.

TABLE 2-2 (continued)

Possible Coal Source Area	Description
<u>Point Lay (Area 2C)</u>	Five coal beds greater than 1 foot thick have been identified. Drilling by the U.S. Bureau of Mines proved a 20-foot bed with a 14° dip. A 13-foot coal seam exposure was found to be a 19 to 20 foot thick bed. A bulk sample was obtained from a 70-foot adit. A 4 to 5-foot coal bed, two shale beds 2 to 3-feet thick, and a 5 to 6-foot coal bed were found in the section overlying the 20-foot bed. This deposit could be mined by methods described in conceptual surface mine Model 6 or conceptual underground mine Model 6. Coal resource estimates vary from 17 to 518 million tons for this area.
<u>Deadfall Syncline (Area 6)</u>	Twelve auger drill holes have been drilled in a combined USGS-USBM investigation and the thickness coal intersection found was 14.7 feet. A synclinal structure is reported but no dips are given. Mining potential appears good but insufficient information is available to relate this area to any of the conceptual mine models.
<u>Cape Beaufort (Area 7A)</u>	Twenty-six coal beds have been identified in an 18-hole USGS-USBM drilling program. The thickest coal beds intersected were 15 to 17-feet, 12 to 13-feet and 9.2-feet thick. Dips were 14° to 20°. Coal resources are estimated to be 35 million tons measured, 312 million tons indicated, and 186 million inferred. This deposit could be mined in a similar manner to conceptual surface mine Model 5.

TABLE 2-2 (continued)

<u>Possible Coal Source Area</u>	<u>Description</u>
<u>Cape Beaufort (Area 7B)</u>	Nine coal beds were sampled in a combined USGS-USBM investigation. The thickest seam sampled in outcrop was 8.8 feet. Dips are generally 30° to 40° and as high as 50°. The steep dips suggest a shallow surface mine as in conceptual surface mine Model 7 or conceptual underground mine Model 7.
<u>Corwin-Thetis (Area 8)</u>	Coal beds near Corwin Bluff dip 45° to 52°, and those at the Thetis mine at 16° to 24°. Seventeen coal beds between 2.5 and 9 feet thick have been measured. In the area of shallower dip conceptual surface mine Models 5 or 6 would be applicable. The Corwin Bluff area has been previously mined by underground methods from the sea cliff. Resources are estimated to be 49 million tons in the indicated category and 484 million tons in the inferred category.
<u>Kallarichuk (Area 12 ABC)</u>	Coal beds up to 3 feet thick and dipping at 25° to 50° are reported in this area. For the shallower dipping beds, shallow surface mines are suggested as in conceptual surface mine Model 5.
<u>Ambler River (Area 14 AB)</u>	The only references to coal occurrences are in the form of coal float in the rivers. Insufficient information is available therefore to relate the conceptual model mines to this area.
<u>Chicago Creek Upper Kugruk (Area 18A-H)</u>	Conceptual surface mine Model 7 and conceptual underground mine Model 7 were specifically designed for the coal deposit at the Chicago Creek Mine.

2.5 COST OF MINING

Costs were estimated for owning and operating mines corresponding to each of the six surface and underground mine models. The results of these estimates are summarized in Tables 2-3 and 2-4 for underground and surface mines respectively. Table 2-5 compares the costs of surface and underground mines. These costs were developed by starting with the actual costs being experienced in the Lower 48, then factoring up for scale of operations and the higher costs of working in a harsh climate and remote areas. Although accurate cost estimates can be developed only for detailed, site-specific mine plans, these costs give a fair approximation of the costs to be expected at the alternative mining scales.

From Table 2-5 it is obvious that surface mines would be three to four times less costly per ton than underground mines. Given the logistical problems posed by underground mines, and the anticipated difficulty in obtaining the highly skilled operators that an underground mine would require, it is clear that surface mines are preferable, even if coal had to be transported much farther from a surface mineable deposit. A cost difference of \$100 or more per ton could pay for transport over a considerable distance. For this reason only, surface mining concepts were considered in the economic analysis in Chapter 4.0.

TABLE 2-3
ESTIMATION OF TOTAL MINING (AND OTHER SITE FACILITIES) COSTS
FOR SIX UNDERGROUND MINE MODELS IN NORTHWESTERN ALASKA

Category	Mine Model	Initial Capital Cost Per Ton (\$)	Capital Replacement Recovery Per Ton (\$)		
Capital Costs	1	7.50	4.50	12.00	
	2	7.50	4.50	12.00	
	3	7.50	4.50	12.00	
	4	7.50	4.50	12.00	
	5	7.50	4.50	12.00	
	6	6.00	5.00	11.00	
		Labor @\$130 Per Man-Shift (\$)	Per Ton (x Factor of 3 for NW Alaska) (\$)	Other Costs (\$)	Total Costs (\$/ton)
Operating Costs	1	65.00	87.00	30.00	182.00
	2	65.00	87.00	30.00	182.00
	3	65.00	87.00	30.00	182.00
	4	43.00	87.00	30.00	160.00
	5	43.00	87.00	30.00	160.00
	6	26.00	63.00	21.00	110.00
Total: Capital and Operating Costs	1				194.00
	2				194.00
	3				194.00
	4				172.00
	5				172.00
	6				121.00

Source: Dames & Moore

TABLE 2-4

ESTIMATION OF TOTAL MINING (AND OTHER SITE FACILITIES) COSTS FOR SIX SURFACE MINE MODELS IN NORTHWESTERN ALASKA

Category	Mine Model	Conterminous Lower 48 Surface Coal Mining Cost Per Cubic Yard (\$)(1)	Scale of Operations Multiplier(2)	Northwest Alaska Multiplier(3)	Seasonal Working Multiplier(4)	Inclusion of Camp and Other Facilities Multiplier	Net Northwest Alaska Cost Per Cubic Yard (\$)(5)	Total Cubic Yards Per Year (1000)	Total Cost Per Year (\$1000)	Coal Tons Per Year (1000)	Total Mine & Facilities Cost Per Ton (\$)
Capital Costs											
	1	0.70	2.0	1.5	2.0	1.90	7.98	190	1,500	0.1	15.00
	2	0.70	1.9	1.5	2.0	1.80	7.16	1,900	8,600	0.8	17.20
	3	0.70	1.8	1.5	2.0	1.70	6.43	2,910	18,700	1	18.70
	4	0.70	1.7	1.5	2.0	1.60	5.71	18,850	106,000	5	21.20
	5	0.70	1.5	1.5	2.0	1.60	5.04	37	186	10	18.60
	6	0.70	1.4	1.5	1.0	1.50	2.20	245	539	60	8.98
	7	0.70	1.3	1.5	1.0	1.50	2.05	781	1,601	190	8.42
Operating Costs											
	1	1.40	2.6	3.0	0.9	1.70	16.71	190	3,200	0.1	32.00
	2	1.40	2.4	3.0	0.9	1.60	14.52	1,200	17,400	0.8	34.80
	3	1.40	2.2	3.0	0.9	1.50	12.47	2,910	36,300	1	36.30
	4	1.40	2.0	3.0	0.9	1.40	10.58	18,550	196,300	5	39.26
	5	1.40	1.8	3.0	0.9	1.30	8.85	37	327	10	32.70
	6	1.40	1.5	3.0	1.0	1.25	7.88	245	1,931	60	32.18
Total: Capital and Operating Costs:											
	1										47.00
	2										52.00
	3										55.00
	4										60.47
	5										51.30
	6										41.16

Source: Dames & Moore

1. Cost in Lower 48 for a large-scale surface mine. Cost is per cubic yard stripped, including overburden.
2. Correction factor to reflect the smaller scale of operations.
3. Correction factor for working in a remote area and harsh climate.
4. Correction factor to reflect low equipment utilization assuming that Models 1-5 shut down for winter.
5. Correction factor for camp facilities which must be provided when mining in a remote area.

TABLE 2-5

ESTIMATED CAPITAL AND OPERATING COSTS FOR COAL MINING OPERATIONS IN NORTHWESTERN ALASKA
(PER TON OF PRODUCTION BASIS)

Mine Model	Annual Production Capacity (Tons)	OPEN PIT OPERATION			UNDERGROUND OPERATION		
		Capital Costs	Operating Costs	Total Costs	Capital Costs	Operating Costs	Total Costs
1	100	15.00	32.00	47.00	12.00	182.00	194.00
2	500	17.20	34.80	52.00	12.00	182.00	194.00
3	1,000	18.70	36.30	55.00	12.00	182.00	194.00
4	5,000	21.20	39.26	60.47	12.00	160.00	172.00
5	10,000	18.60	32.70	51.30	12.00	160.00	172.00
6	60,000 or more ⁽¹⁾	8.98	32.18	41.16	11.00	110.00	121.00

Source: Dames & Moore

(1) Economies of scale are assumed to be constant for tonnages above 60,000.

3.0 ECONOMIC ANALYSIS OF COAL TRANSPORTATION MODES

3.1 INTRODUCTION

The principal objectives of Task 3 are to:

- Review the existing transportation infrastructure of northwest Alaska;
- Identify the modes most suitable to transport coal from points of production to centers of demand and define advantages and disadvantages attendant with their use; and
- Assess the costs of each transportation mode.

3.2 EXISTING TRANSPORTATION INFRASTRUCTURE IN NORTHWEST ALASKA

Northwest Alaska's transportation needs are unique compared to those of the Lower 48 states. This uniqueness is a result of the wide distribution of small population centers (generally less than 300 people) across a large, geographically diverse and relatively inaccessible area. With few exceptions, these centers are not interconnected by roads; none are linked by highway connections to major population centers such as Anchorage or Fairbanks.

Within the study area, three modes of commodity transport exist:

- Aviation
- Marine route
- Road infrastructure

Aviation: In general, air transport is economically feasible only for passenger, small freight, and mail deliveries. However, bulk fuel products

and other large-sized commodities have been air-lifted to points within the study area on an emergency basis. Only Nome, Kotzebue, and Unalakleet have facilities sized to accommodate the larger aircraft required for bulk deliveries. Wien Air Alaska and Alaska Airlines are the only two carriers that provide scheduled service to these three communities from points outside of the study area. An unscheduled carrier, Alaska International Air, frequently services the region with Hercules, as well as other large prop-jet aircraft.

Roads: The road system in the study area is relatively limited and consists of a small network of local connecting and service-oriented haul roads. The total length of all service roads in the region is less than 300 miles. A state highway system exists in the Nome area but the system is not connected to the rest of the state. The longest legs in the subsystem are:

- Nome-Teller, 72 miles;
- Nome-Council, 73 miles;
- Nome-Taylor, 105 miles;
- Nome-Solomon, 32 miles.

Local service roads serve all the communities within the region. Some are designated state routes, some are included under the Local Service Roads and Trails Program, and some are of varied origins and include trails. The total length of these roads is about 200 to 300 miles; however, there is no inventory of these roads.

During the winter, some soils and frozen waterways are sufficiently stable so that they can be used by heavy-duty highway vehicles. In many localities in northwest Alaska, it is possible to construct temporary, limited use roads out of ice and snow. Such temporary roadways are relatively inexpensive to construct and maintain and are usable for up to six months. However, the presence of snow or ice is not assured; some winters may result in little appreciable snowfall or earliest snowfall late into the winter. Under such conditions, winter access is not always assured or is limited.

Off-road vehicles in use in the study area range from small, one- or two-passenger snowmobiles to large crawler tractors capable of pulling loads of 60 or more tons on sleds or tracked trailers. The characteristics and operating costs of off-road haul vehicles in common use, and the cost of construction and maintaining winter trails and roads, are given in Appendix IV.

Marine Modes: In the study area, virtually all commodities having low value-to-weight ratios are of a very large size and are shipped by water. This is accomplished through the use of tug-barge combinations sized for ocean, coastal and/or river transport. Black Navigation and Arctic Lighterage are the two privately-owned barge companies maintaining fleets within the study area. Interstate ocean shipping is conducted by the Bureau of Indian Affairs' ship North Star III.

At present, the study area is served by two types of vessels -- tug-barge combinations and general cargo ships from the ports of Nome and Kotzebue. By and large, general cargo ships are restricted in their service to coastal communities. The barge combinations, however, can serve a much wider area. Because of the shallow depth of many of the bodies of water in northwest Alaska, much of the cargo consigned to arctic destinations must be lightered. This requirement directly increases the cost of transporting any item or commodity.

Inland water transportation is largely limited to small boats or shallow-draft, tug-barge combinations. Because there are no docking or cargo loading/unloading facilities on most of the rivers, and insofar as few villages have cargo handling equipment, the barge carrier often must carry out this task and include the cost of this operation in the tariff.

Interstate transportation of cargo is provided by both the Seattle-based Bureau of Indian Affairs' ship North Star III, and by ocean-going tug-barge combinations. The North Star III is a Victory-class ship with a displacement of 10,000 dead weight tons (DWT) and a loaded draft of 28.5 feet. Tugs range from 2,000 to 9,000 horsepower and draw 12 to 14 feet of water. Barges

include both dry cargo and tanker types of 4,000 to 16,300 DWT capacity with a full-load draft of 16 to 20 feet.

Coastal lighterage and river services are provided by tugs and barges of a smaller size. For this purpose, tugs range from 220 to 1,000 horsepower with drafts of 2.5 to 4 feet. Barges, with drafts ranging 3 to 7 feet, vary from 100 to more than 1,000-ton capacity, contingent upon density of loading. Some of the barges in this fleet are designed for liquid cargo and have a flat deck for top loading of dry cargo.

The shipping season for the study area is determined primarily by the duration of ice-free water. This period varies widely in length throughout the study area, averaging three months or more at St. Michael on Norton Sound, to two months or less at Point Lay on the Chukchi Sea. The ice-free season of the rivers of northwest Alaska is generally more uniform and extends from May to late October. However, at the end of the season, freeze-up of the rivers occurs sooner than in coastal waters, thus limiting river transport of cargo to a period of approximately four months.

3.3 FEASIBLE COAL TRANSPORTATION MODES

Through an analysis of the existing transportation infrastructure of northwest Alaska (in light of economic and operational considerations), Dames & Moore has determined that transportation of coal can be best accomplished through the use of barges and/or through the construction of limited distance haul roads. Transporting coal by aircraft on a regular basis is impractical given limited load capacity, the unavailability of suitable landing facilities at many of the candidate demand centers, and high operating costs. There is, however, the possibility that emergency service coal delivery could be provided on a village-specific basis should the need arise.

Barge transport of coal to various points within the study area appears to be both economically and operationally viable -- particularly if existing

tugs and barges can be used. There are, however, several weaknesses in this mode. Because coal contains less energy per weight unit than diesel fuel and is more cumbersome to handle, its transportation is more labor intensive and requires special handling equipment. To transport coal, some of the existing barges presently available would have to be retrofitted.

Marine transportation costs for the study area depend primarily on the distance traveled and the accessibility of the points served. Cargo delivery via rivers to inland villages or to more northerly centers farther up the northwest coast of Alaska is generally more expensive than cargo delivered closer to the hub ports of Nome and Kotzebue. Because of the shallow draft requirements for tug-barge combinations serving villages located on the Kobuk River, barges cannot generally run at full capacity. However, according to Dave Schuyler (Crowley Maritime, Seattle) 500-ton barges can serve Buckland, Noatak and the Kobuk River communities "... at the right time of year," i.e., during spring high water. Since these communities need only one to three barge loads per year, 500-ton barges are feasible. Coastal communities are already being served by 500-ton barges, which are beached during favorable winds and tides. Tugs and barges are thus able to serve all communities within the study area.

Under short haul conditions, motor vehicle transport may be feasible. Most mine areas will require the transport of coal from the mine site to the on-loading barge facilities by truck. Certain costs are inherent each time coal is reloaded or unloaded. Under short haul conditions, the continued transport by truck may result in a savings in time and cost in handling by trucking coal directly from the mine to the plant or village. This savings may be offset somewhat by the capital costs of road construction. The maximum feasible distance for haul roads will vary depending upon the rate of use, type of construction, and climatic, geographic, and labor considerations. The existing road system connecting Nome with Council, Solomon and Taylor could be used to transport coal barged to Nome to these inland communities.

The construction of permanent, limited distance haul roads (less than 25 miles) in the study area would cost about \$175,000 per mile (see Section 3.5). In addition, maintenance costs of such roads are high due to climatic, geographical, and labor considerations. Therefore, to justify the construction and maintenance of permanent roads, the utilization rates and potential savings achievable compared to other modes of transportation must be analyzed. In general, roads greater than 30 miles are less feasible than barge links for water-connected destination.

Off-road transportation during the winter season is accomplished through the preparation of temporary roadways of compacted snow and ice capable of supporting conventional high equipment. While the cost of snow roads varies between \$1000-\$3000 per mile as shown in Appendix IV, average costs for the types of roads needed for coal haul are estimated to average under \$6,500 per mile. Maintenance costs for snow-roads for the project are estimated to average under \$2,500 per mile per season (see Appendix IV).

While these costs appear to be more favorable than the high cost of conventional roads, there are several limitations to winter transport of coal in the study area. Primarily, transport is limited by the hauling capacity of the vehicles in relationship to the demand and initial costs and continual maintenance costs of the vehicles. Other potential difficulties include the problems associated with having to stockpile coal from summer-only mining production.

Winter conditions are generally not favorable for coal hauling. Major criticisms of winter operations include:

- The presence of snow is not always assured. This could result in a delay in the start of winter hauling due to inaccessible mine site stockpiles.
- Some form of summer access road would be needed to get mining equipment to the sites for summer mining. Construction costs for these access roads would negate the cost savings associated with snow road versus summer road construction.

- The decrease in average vehicle speeds (generally 10 to 20 mph in winter versus 20 to 40 mph in summer) may result in the need for a greater number of vehicles and a resulting increase in capital and maintenance costs.

For the above reasons, winter roads were eliminated from further consideration and do not appear in the economic analysis in Chapter 4.0.

3.4 BARGE TRANSPORT MODES AND COSTS

As noted above, barges offer a feasible means for moving coal over long distances. Tugs would be limited to moving a single barge. Although with the exception of Nome and Kotzebue none of the coastal community ports has barge docking and unloading facilities, a shallow draft 500-ton barge could, at favorable wind and tide, be beached, then unloaded by a front-end loader. Coal from a coastal or near-coastal resource could be barged to all communities in the study area.

According to Crowley Maritime (Bill Troy, Seattle, 1981) a tug and 500-ton barge could travel at about five to six knots. Allowing for waiting for favorable tides, daily distances could average 100 (statute) miles. Crowley already maintains tugs and 500-ton barges suitable for coal service in Kotzebue and Nome. They hazarded a rough guess that such a service would cost \$5,000 to \$7,000 per day.

In addition to their existing equipment, Arctic Lighterage (the Alaska subsidiary of Crowley Maritime) indicated their willingness to purchase new equipment if long-term contracts could be secured and the routes found to be profitable. The current replacement cost of a 1200 HP tug is about \$750,000 and a 500-ton barge is about \$500,000. At a capital recovery factor of 0.05102 (see Section 4.3), the annual ownership cost of a tug and barge is \$64,000. Assuming the equipment could be used half the year, the daily ownership cost is \$350.

Daily operating costs for shallow draft and coastal tugs and barges are shown in Table 3-1. These costs have been used to estimate the levelized cost of moving coal within the study area. The levelized cost reflects the inflationary increase in costs due to rising fuel and oil prices levelized over a period of 30 years. Table 3-2 integrates the information on daily ownership and operating costs and shows transportation costs as a function of distance. The costs assume two days per trip for loading and unloading, operating costs at "at port" rates, and an average headway of 100 miles per day. The per-ton costs shown are interpolated for actual distances in the economic analysis in Chapter 4.0.

3.5 COAL HAUL ROAD MODES AND COSTS

Construction costs for haul roads in the study area depend on the design and construction standards to which they are built, location, geological considerations, and the availability of labor. Representative costs for construction of existing roads are given in Tables 3-3 based on data provided by the Alaska Department of Transportation (1980). Most roads required for coal haul to the various plants or villages are anticipated to be one-lane roads costing \$175,000 per mile to construct. Although this cost is significantly below road construction contract costs for 1972 to 1980 shown in Table 3-3, contracted roads for this period reflect a higher grade of construction than would be needed or anticipated for haul roads; many of these contracts reflect two-lane roads. Annual ownership costs are \$11,760 per mile at a capital recovery factor of .0672 (see Section 4.3).

Road maintenance costs are categorized as road surface maintenance, roadside facilities, traffic services, and snow and ice control costs. Because of the lack of road maintenance stations, the majority of roads in the study area are open only when weather conditions allow.

Table 3-4 summarizes the direct highway maintenance costs for the three major roads that radiate from Nome: the Nome-Teller, Nome-Taylor, and Nome-Council highways. Direct costs, consisting of expenditures on highway

TABLE 3-1
COASTAL TUG AND BARGE DAILY OPERATING COSTS⁽¹⁾
(1981 \$)

	<u>Under Way</u>	<u>At Port</u>
Fuel, 6 Gal/100 HP/Hr @ \$1.50/gal ⁽²⁾	\$2160	\$ 215
Oil and Lubricants	86	8
Crew	3384	3384
Subsistence	271	271
Maintenance and Repair	1395	1395
Stores, Supplies & Equipment	<u>418</u>	<u>418</u>
Total Daily Operating Cost ⁽³⁾	\$7714	\$5690

Source: Alaska Department of Transportation & Public Facilities, 1980.

Notes: (1) Alaska Department of Transportation & Public Facilities (1980) data are presented in 1978 dollars. These costs were inflated at 15 percent annually to 1981 dollars.

(2) 1200 HP tug, 135 feet x 35 feet barge (500 tons).

(3) Additional barges increase only the cost of fuel at a rate of 10 percent per barge.

TABLE 3-2

COSTS FOR BARGE TRANSPORTATION OF COAL
(\$1000)

<u>Miles</u>	<u>Distance Round Trip(Days)</u>	<u>Operating Cost/Trip⁽¹⁾ (\$1000)</u>	<u>Ownership Cost/Trip⁽¹⁾ (1000)</u>	<u>Total Cost/Trip (\$1000)</u>	<u>Total Cost/Ton (\$)</u>
10	2	12.9	0.7	13.6	27.2
50	3	19.1	1.1	20.2	40
100	4	26.8	1.4	28.2	56
150	5	34.5	1.8	36.3	73
200	6	42.2	2.1	44.3	89
250	7	50.0	2.5	52.5	105
300	8	57.6	2.8	60.4	121
350	9	65.4	3.2	68.6	137
400	10	73.1	3.5	76.6	153
450	11	80.1	3.9	83.9	168
500	12	88.9	4.2	93.1	186
550	13	96.6	4.6	101.2	202

(1) Assumes one day load and one day unloading at "at port" costs. Travel times assume an average headway of 100 statute miles per day. Daily costs are obtained from Table 3-1.

TABLE 3-3
ROAD CONSTRUCTION CONTRACT COSTS

<u>Year Constructed</u>	<u>Location</u>	<u>Length</u>	<u>Cost (\$1000)</u>	<u>Cost Per Mile (\$1000)</u>	<u>Remarks</u>
1972	Galena	0.48	83	173	Interior
1975	Nome	4.40	936	213	Nome-Council
1975	Galena	1.26	234	186	Interior
1976	Nome	11.98	2942	246	Nome-Council
1976	Kotzebue	1.60	336	210	Center Creek
1977	Wales	0.66	231	350	Village Road
1980	Pt. Hope	1.41	456	325	Village Road

Source: Alaska Department of Transportation & Public Facilities, personal communication, 1981.

TABLE 3-4
ANNUAL HIGHWAY MAINTENANCE COSTS
(dollars per mile)

	<u>Direct</u>	<u>Indirect</u>	<u>Buildings</u>	<u>Administration</u>	<u>Total</u>
Nome-Taylor	\$2682	\$ 963	\$373	\$298	\$4316
Nome-Teller	4311	1548	599	479	6973
Nome-Council	2892	1038	402	321	<u>4653</u>
Average (rounded)	3300	1200	460	370	5300

Source: Alaska Department of Transportation & Public Facilities, personal communication, 1981.

maintenance and operation for those sections of the road that are maintained, average \$3,298 per mile. Indirect costs, consisting of expenditures for employee benefits, equipment servicing, and administration costs average \$2,000 per mile. The total average cost of maintenance for the three major roads is \$5,300 per mile. However, since coal haul roads need not be maintained at the same standard as public roads, half this cost, or \$2,750 per mile is assumed.

Combining the \$11,760 ownership cost with the maintenance cost yields an annual total cost of \$14,500 per mile. This cost was used in the analyses in Chapter 4.0. It is clear that the high cost of roads limits their feasibility to short hauls or high use situations.

On-road summer transportation of coal is anticipated to be done by 2-ton and 20-ton capacity trucks, the choice depending on the scale of mining operations. The estimated capital costs of these vehicles are \$25,000 and \$120,000 respectively. For an expected life of 10 years, the annualized ownership costs are \$3,000 and \$14,000 respectively.

The levelized cost of operating each vehicle is estimated at \$1.15 per mile assuming 50 percent of operating costs are for fuel. To facilitate the analysis, levelized operating costs are converted to cost per ton-mile. For 2-ton trucks, the levelized operating cost per ton-mile is \$1.15. A 20-ton truck would experience a ten-fold economy-of-scale. Its operating cost per ton-mile is \$0.12.

Various transportation modes and their associated costs were evaluated to determine suitable modes. Requirements evaluated included:

- Distance from nearest potential mine source to the generating plant or village stockpile area;
- Annual tonnage required for each scenario;
- Transportation mode most likely to be used (land or water transport);
- Average speed of vehicles;
- Average time of travel, loading, and unloading;

- Number and size of equipment needed for transport and stockpiling operations.

Tables 3-5 and 3-6 are used in determining transportation modes and costs for specific example scenarios discussed in Chapter 4.0.

As discussed previously, assumptions are made in estimating project specific transportation costs. These included:

- Average speed of trucks on summer roads is estimated at 35 mph.
- The maximum number of haul days has been assumed at 90 days to allow for maintenance, periodic unfavorable weather conditions, and other contingencies. Road maintenance or construction operations are assumed to occur outside of the 90 work-day hauling period either before the start-up of summer hauls or concurrently during winter haul periods.
- Workers are anticipated to work 8 hours per day and 5 days per week..

Table 3-5 presents a matrix table for determining the most feasible equipment for transportation of coal on summer roads. Included are the number of vehicles needed, the total number of loads hauled per day, the total tonnage hauled per day, and the percent of the 90 work-day season expended in hauling the respective annual tonnage and distances. For example, for a subscenario requiring 10,000 annual tons of coal to be hauled a one-way distance of 20 miles, two 20-ton trucks would be required with each hauling 5 loads per day. The combined tonnage hauled per day is 200 tons. This operation would take only 56 percent of the haul season, allowing for later use of these same vehicles at another site, if feasible.

Based on the results of Table 3-5, a summary of levelized capital and operating costs was obtained (see Table 3-6). From Table 3-6 for the

TABLE 3-5

NUMBER OF VEHICLES/LOADS PER DAY/TONS PER DAY/PERCENT OF SEASON USED
(BASED ON SUMMER ROAD TRANSPORTATION MODE)

Annual Tonnage	One-way Distance from Mine to Plant		
	10 Miles	20 Mile	30 Miles
100 Tons	(1) 2-ton truck 8 loads/day 16 tons/day 7% of season	(1) 2-ton truck 5 loads/day 10 tons/day 11% of season	(1) 2-ton truck 3 loads/day 6 tons/day 19% of season
500 Tons	(1) 2-ton truck 8 loads/day 16 tons/day 35% of season	(1) 2-ton truck 5 loads/day 10 tons/day 56% of season	(1) 2-ton truck 3 loads/day 6 tons/day 93% of season
1,000 Tons	(1) 2-ton truck 8 loads/day 16 tons/day 69% of season	(2) 2-ton truck 10 loads/day 20 tons/day 56% of season	(2) 2-ton truck 6 loads/day 12 tons/day 93% of season
2,000 tons	(2) 2-ton trucks 16 loads/day 32 tons/day 63% of season	(3) 2-ton trucks 15 loads/day 30 tons/day 67% of season	(1) 20-ton truck 3 loads/day 60 tons/day 37% of season
5,000 tons	(1) 20-ton truck 8 loads/day 160 tons/day 35% of season	(1) 20-ton trucks 5 loads/day 100 tons/day 56% of season	(1) 20-ton trucks 3 loads/day 60 tons/day 93% of season
10,000 tons	(1) 20-ton truck 8 loads/day 160 tons/day 69% of season	(2) 20-ton trucks 10 loads/day 200 tons/day 56% of season	(3) 20-ton trucks 9 loads/day 180 tons/day 56% of season
20,000 tons	(2) 20-ton trucks 16 loads/day 320 tons/day 63% of season	(3) 20-ton trucks 15 loads/day 300 tons/day 67% of season	(4) 2-ton trucks 12 loads/day 240 tons/day 83% of season

Source: Dames & Moore. Please refer to text for assumptions.

TABLE 3-6

LEVELIZED COST PER TON-MILE

Annual Tonnage	Cost Category	One-way Distance from Mine to Plant		
		10 Miles	20 Miles	30 Miles
100 Tons	Capital Cost	\$3.00	\$1.50	\$1.00
	Operating Costs	\$1.15	\$1.15	\$1.15
	TOTAL	\$4.14	\$2.65	\$2.15
500 Tons	Capital Cost	\$0.60	\$0.30	\$0.20
	Operating Costs	\$1.15	\$1.15	\$1.15
	TOTAL	\$2.75	\$1.45	\$1.35
1000 Tons	Capital Cost	\$0.30	\$0.30	\$0.20
	Operating Costs	\$1.15	\$1.15	\$1.15
	TOTAL	\$1.45	\$1.45	\$1.35
2000 Tons	Capital Cost	\$0.30	\$0.225	\$0.23
	Operating Costs	\$1.15	\$1.15	\$0.12
	TOTAL	\$1.45	\$1.38	\$0.35
5000 Tons	Capital Cost	\$0.28	\$0.14	\$0.09
	Operating Costs	\$0.12	\$0.12	\$0.12
	TOTAL	\$0.40	\$0.26	\$0.21
10,000 Tons	Capital Cost	\$0.14	\$0.14	\$0.14
	Operating Costs	\$0.12	\$0.12	\$0.12
	TOTAL	\$0.26	\$0.26	\$0.26
20,000 Tons or more	Capital Cost	\$0.14	\$0.105	\$0.09
	Operating Costs	\$0.12	\$0.12	\$0.12
	TOTAL	\$0.26	\$0.23	\$0.21

Source: Dames & Moore

above example, the capital cost of two 20-ton trucks hauling a total annual tonnage of 20,000 tons and a round-trip distance of 40 miles is \$0.14 per ton-mile. The operating costs for this subscenario is \$0.12 per ton-mile. These costs are used in the economic analysis in Chapter 4.0. Where distances or tonnage moved fall between the specified values on Table 3-6, they are not interpolated. Instead, the higher cost is used for conservatism.

4.0 DEVELOPMENT AND ECONOMIC ANALYSIS OF COAL ENERGY SCENARIOS

4.1 INTRODUCTION

The preceding chapters described the resource base and infrastructure of the study area relative to coal utilization. Using the technologies and cost estimates developed in those chapters, the feasibility of coal for heat and power in the study area can now be assessed.

The assessment of feasibility for the study area per se is predicated on the analysis of several scenarios, each of which exemplifies a typical situation within the study area. Scenario 1 considers electricity generation for the Kotzebue to Kobuk region only (see Figure 4-1). Two sites, Kotzebue and Kiana, were compared for a regional power plant location. Although economies of scale can be realized through centralizing power generation, long and expensive transmission lines are needed.

Scenario 2 explores subregional power plants serving clusters of villages. The power is transmitted 50 miles or less to communities within the cluster.

Scenario 3 explores the option of coal-fired electric plants serving single villages, obviating the need entirely for costly transmission lines.

Scenarios 4 and 5 also use local power plants in each community; however, coal is supplied from one central mine and distributed by barge throughout the study area. In Scenario 4 the mine is located along the Cape Beaufort coast between Point Hope and Point Lay. In Scenario 5 the mine is at Chicago Creek.

In each scenario, it is assumed that diesel space heat is replaced by electric space heat and direct burning of coal. Coal is obtained from the most likely local sources. Ten percent of diesel space heat is assumed replaced by electric space heat. The balance of diesel space heat demand is assumed replaced by direct burning of coal. All scenarios are based on the electrical and heating demands for the year 2000 shown on Table 1-2.

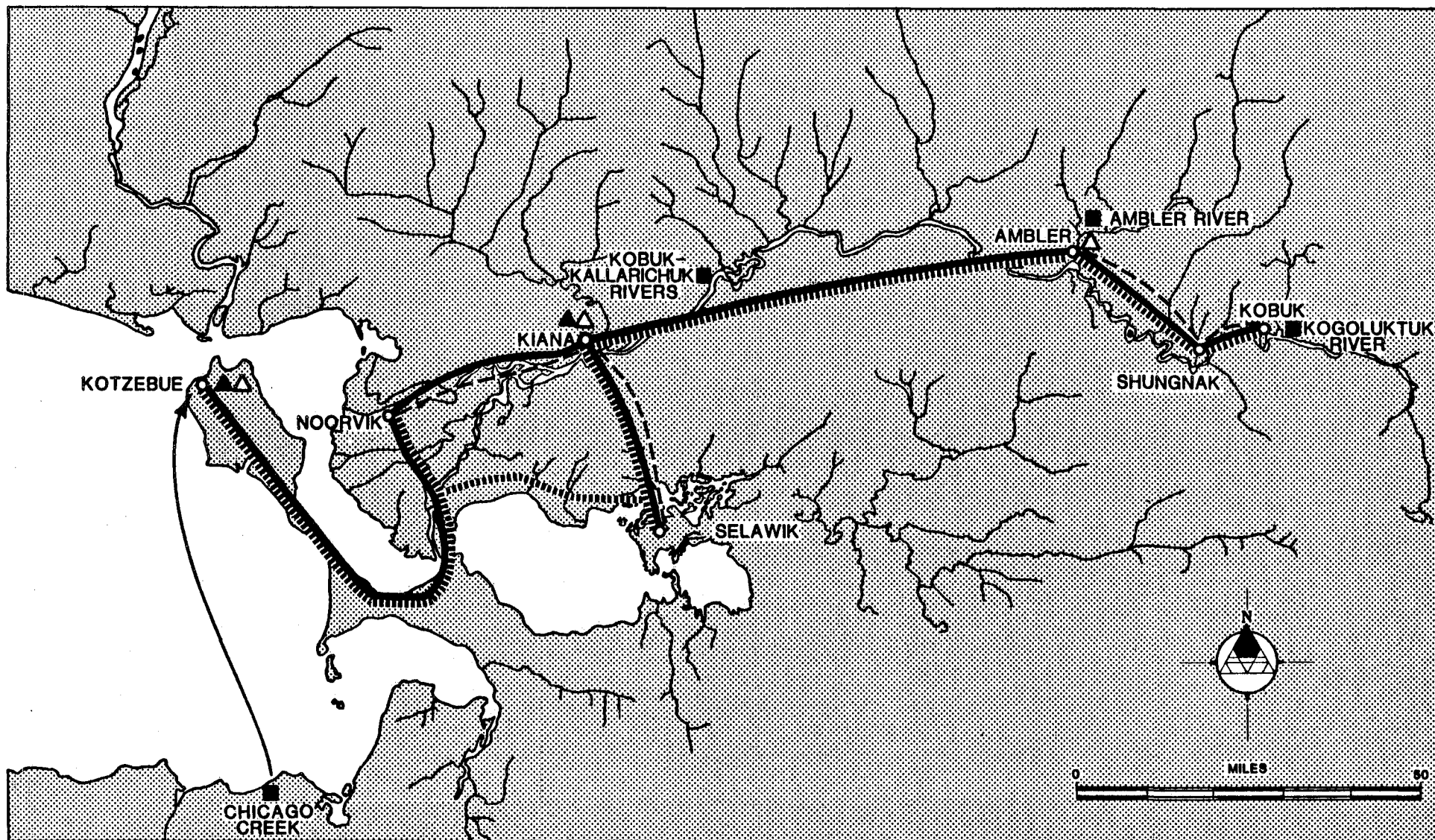


Figure 4-1

SCENARIOS 1 AND 2:
KOTZEBUE - KOBUK REGION

KEY:

- ▲ REGIONAL POWER PLANT LOCATION
- △ SUBREGIONAL POWER PLANT LOCATION
- POWER PLANT IN KIANA (SUBSCENARIO 1.1)
- ▤ REGIONAL SCENARIO - TRANSMISSION LINES
- POWER PLANT IN KOTZEBUE (SUBSCENARIO 1.2)
- SUBREGIONAL SCENARIOS - TRANSMISSION LINES
- COAL OCCURRENCES

By following the above described approach, a sensitivity analysis has been structured that compares the feasibility of technologies and sources for the study area. This will indicate which coal utilization approaches bear further study.

4.2 SCENARIO DESCRIPTIONS

SCENARIO 1: REGIONAL ELECTRIC GENERATION

One regional power plant supplies electricity to the communities in the Kotzebue-Kobuk region. Two possible plant sites are compared. In these scenarios, coal-fired generators provide electricity for present needs plus 10 percent of the space heating needs now served by diesel. The generating plants and mines are sized for anticipated needs in the year 2000. The remaining space heating needs are assumed to be served by coal from sources apparently suitable from a proximity and qualitative standpoint.

Subscenario 1.1, Kiana Power Plant: Subscenario 1.1 postulates a regional power plant at Kiana capable of generating all the electricity requirements and 10 percent of the space heat needs of Ambler, Kiana, Kobuk, Kotzebue, Noorvik, Selawik, and Shungnak. To satisfy these requirements, a 5 MW coal-fired steam plant and 351 miles of 69 KV overhead transmission line are necessary. The coal is obtained from the Kobuk-Kallarichuk Rivers deposits and trucked to Kiana. The remaining space heating needs of the communities are met by the direct burning of coal from the sources as shown in Table 4-1.

Subscenario 1.2, Kotzebue Power Plant: Subscenario 1.2 postulates a regional power plant at Kotzebue capable of generating all the electricity requirements and 10 percent of the space heating needs of Ambler, Kiana, Kobuk, Kotzebue, Noorvik, Selawik, and Shungnak. To satisfy these requirements a 5 MW coal-fired steam plant and a distribution system of 368 miles of 69 KV overhead transmission line is necessary. The coal for the Kotzebue plant is obtained from the Chicago Creek deposit south of Kotzebue on the northern

TABLE 4-1
COMMUNITY COAL SOURCES AND TONNAGE

<u>Community</u>	<u>Coal Required⁽¹⁾ (Tons/Year)</u>	<u>Coal Source</u>	<u>Transportation Mode and Distance (Miles)</u>
Ambler	453 ⁽²⁾	Ambler River Deposit	Truck (10)
Kotzebue	11,889 ⁽²⁾	Chicago Creek	Truck (10), Barge (80)
Kiana	11,833 ⁽³⁾	Kallarichuk and Kobuk Rivers Deposits	Truck (16)
Noorvik	1,187 ⁽²⁾	Kallarichuk and Kobuk Rivers Deposits	Truck (16), Barge (40),
Selawik	1,233 ⁽²⁾	Kallarichuk and Kobuk Rivers Deposits	Truck (16), Barge (94)
Kobuk	161 ⁽²⁾	Kogoluktuk River Deposits	Truck (6)
Shungnak	<u>495⁽²⁾</u>	Kogoluktuk River Deposit	Truck (12)
TOTAL	27,252		

(1) Coal is assumed to have a heat content of 10,000 Btu. For Chicago Creek, which is known to be lignite, correct for the lower heat content by multiplying tonnage by 1.54.

(2) Ninety percent of direct heating needs (cf Table 1-2)

(3) Kiana space heat (90 percent) included.

Seward Peninsula. Under this scenario Kiana needs only 692 tons of local coal (see Table 4-1) for 90 percent of space heating needs whereas Kotzebue requires 39,687 tons to accommodate power generation and local space heating.

SCENARIO 2: SUBREGIONAL ELECTRIC GENERATION

Subregional power plants located within and serving a cluster of villages generate electric power requirements as well as 10 percent of the space heating requirements now served by diesel. The power plants and mines are sized for anticipated needs in the year 2000.

The subregional scenarios include Kotzebue as a stand-alone subregion. This allows the comparison of costs for coal delivered and burned in Kotzebue with the costs for the entire region calculated in the regional scenario. The subregional scenarios also include a cluster of villages served by a single mine at the Kallarichuk-Kobuk Rivers deposits and a cluster of villages served by two small mines at the Ambler deposit and the Kogoluktuk deposit.

Subscenario 2.1: Subscenario 2.1 provides for a subregional power plant located at and serving Kotzebue alone. This facility, which provides 10 percent of the electric space heating needs of Kotzebue, consists of a 3 MW coal-fired steam plant. Annual coal requirements for generator and remaining direct fired coal space heating (32,309 tons) is mined at Chicago Creek, transported 16 miles via truck to the south shore of Kotzebue Sound, then barged 56 miles to Kotzebue.

Subscenario 2.2: A subregional power plant located at Kiana (0.5 MW) satisfies both the electricity requirements and 10 percent of the space heating needs of Kiana, Noorvik, and Selawik. To serve this generating facility and the remainder of Kiana's space heating needs, coal (2,116 tons) is mined at the Kallarichuk-Kobuk River deposits and trucked 16 to 22 miles to Kiana. Electricity is transmitted 28 and 45 miles, respectively, to Noorvik and Selawik by overhead 69 KV lines. The required coal for the remaining space

heating needs of Noorvik and Selawik is 1,187 and 1,233 tons, respectively, and comes from the same source of supply, transported first by truck and then by barge to the communities.

Subscenario 2.3: This subscenario provides for a subregional electric power plant located at Ambler (0.2 MW) capable of serving the electricity requirements as well as 10 percent of the space heating needs of Ambler, Kobuk, and Shungnak. Coal for the Ambler generating facility and the remainder of Ambler's space heating needs (1,080 tons) is obtained from the Ambler River deposit and is transported by truck to Ambler. Electricity is transmitted by overhead 69 KV lines 42 miles to Shungnak and an additional 9 miles to Kobuk. Coal for remaining space heating needs at Shungnak and Kobuk, 495 and 161 tons, respectively, comes from the Kogoluktuk deposit 12 miles northeast of Shungnak and is transported by truck to each of the villages.

SCENARIO 3: LOCAL ELECTRIC GENERATION

Electric power for representative small villages within the study area is generated within each village by coal-fired steam turbines. These generators provide for existing electric needs plus 10 percent of the space heating needs of each community. The remaining space heating needs are assumed to be met by direct burning of coal.

The major advantage of local generation is that costly transmission lines, with their related problems of reliability, are avoided. The major negative aspect is the relatively high cost of small-scale power generation.

Subscenario 3.1: A coal-fired steam generator at Ambler (0.1 MW) provides electricity as well as 10 percent of Ambler's space heating needs (265 tons coal). The remaining space heat needs are met by the direct burning of coal (453 tons). Coal (718 tons) is obtained from a mine 10 miles northwest of Ambler and is transported by truck to Ambler.

Subscenario 3.2: Subscenario 3.1 assumes a coal-fired steam generator at Kiana (0.1 MW) burning 296 tons of coal and capable of providing for the electricity requirements and 10 percent of Kiana's space heating needs. The remaining space heating needs are met by direct burning of coal (692 tons). Coal is mined 16 miles northeast of Kiana at the Kallarichuk and Kobuk Rivers deposits and trucked to Kiana.

Subscenario 3.3: A coal-fired steam generator at Noorvik (0.2 MW) provides electricity as well as 10 percent of Noorvik's space heating needs (559 tons). The remaining space heat needs are met by direct burning of coal (1,187 tons). Coal is obtained from the Kallarichuk-Kobuk River deposits and is barged 40 miles to Noorvik.

Subscenario 3.4: A coal-fired steam generator at Selawik (0.2 MW) provides electricity as well as 10 percent of Selawik's space heating needs (569 tons). The remaining space heat needs are met by the direct burning of coal (1,233 tons). Coal is obtained from the Kogoluktuk River deposits and barged 94 miles to Selawik.

Subscenario 3.5: A coal-fired generator at Shungnak (less than 0.1 MW) provides electricity as well as 10 percent of Shungnak's space heating needs (275 tons). This remaining space heating needs are met by direct burning of coal (495 tons). Coal is obtained from the Kallarichuk-Kobuk River deposits and trucked 12 miles to Shungnak.

Subscenario 3.6: A coal-fired generator at Kobuk (less than 0.1 MW) provides electricity as well as 10 percent of Kobuk's space heating needs (86 tons). The remaining space heating needs are met by direct burning of coal (161 tons). Coal is obtained from the Kogoluktuk River deposits and trucked 6 miles to Kobuk.

Subscenario 3.7: Same as Subscenario 2.1.

SCENARIO 4: CENTRAL MINE
AT CAPE BEAUFORT, LOCAL POWER GENERATION

In this scenario, coal for the space heat and electrical needs of the entire study area is mined at a Cape Beaufort occurrence (between Point Lay and Point Hope). This area has been mined in the past and is reported to have large reserves (see Section 2.5). The coal is bituminous and is therefore assumed to have a heat value of 11,500 Btu per pound. Further, the mine is assumed at or near the coast and no haul roads are needed. Coal is assumed to be loaded onto 500-ton barges direct from the mine stockpile. These barges then transport the coal to each community in the study area. The transport routes and straight line distances are shown in Figure 4-2. The costs associated with this transport is shown in Table 4-2.

SCENARIO 5: CENTRAL MINE
AT CHICAGO CREEK, LOCAL POWER GENERATION

This scenario is similar to Scenario 4 except that coal for the entire study area is mined at the Chicago Creek mine at the south end of the Kotzebue Sound. The coal is lignitic and is assumed to have a heat content of 6,500 Btu per pound. The barge transportation routes and straight line distances are shown in Figure 4-3. Table 4-3 shows the transportation costs for each community served.

4.3 BASIS AND ASSUMPTIONS FOR DEVELOPING THE SUBSCENARIOS

Coal: The basic demand figures used in the subscenarios are obtained from Table 1-2. Coal requirements for electricity generation for each subscenario are obtained by taking the existing requirements for electricity uses and adding to it 10 percent to account for electric space heat. Coal for the remaining space heat demand (direct coal burning) is obtained by taking 90 percent of the direct heating demand (Table 1-2, column 4). For convenience, the coal demand for each subscenario by mine source is shown in Table 4-4.

Figure 4-2

SCENARIO 4: A CENTRAL MINE
AT CAPE BEAUFORT WITH
BARGE TRANSPORTATION
OF COAL

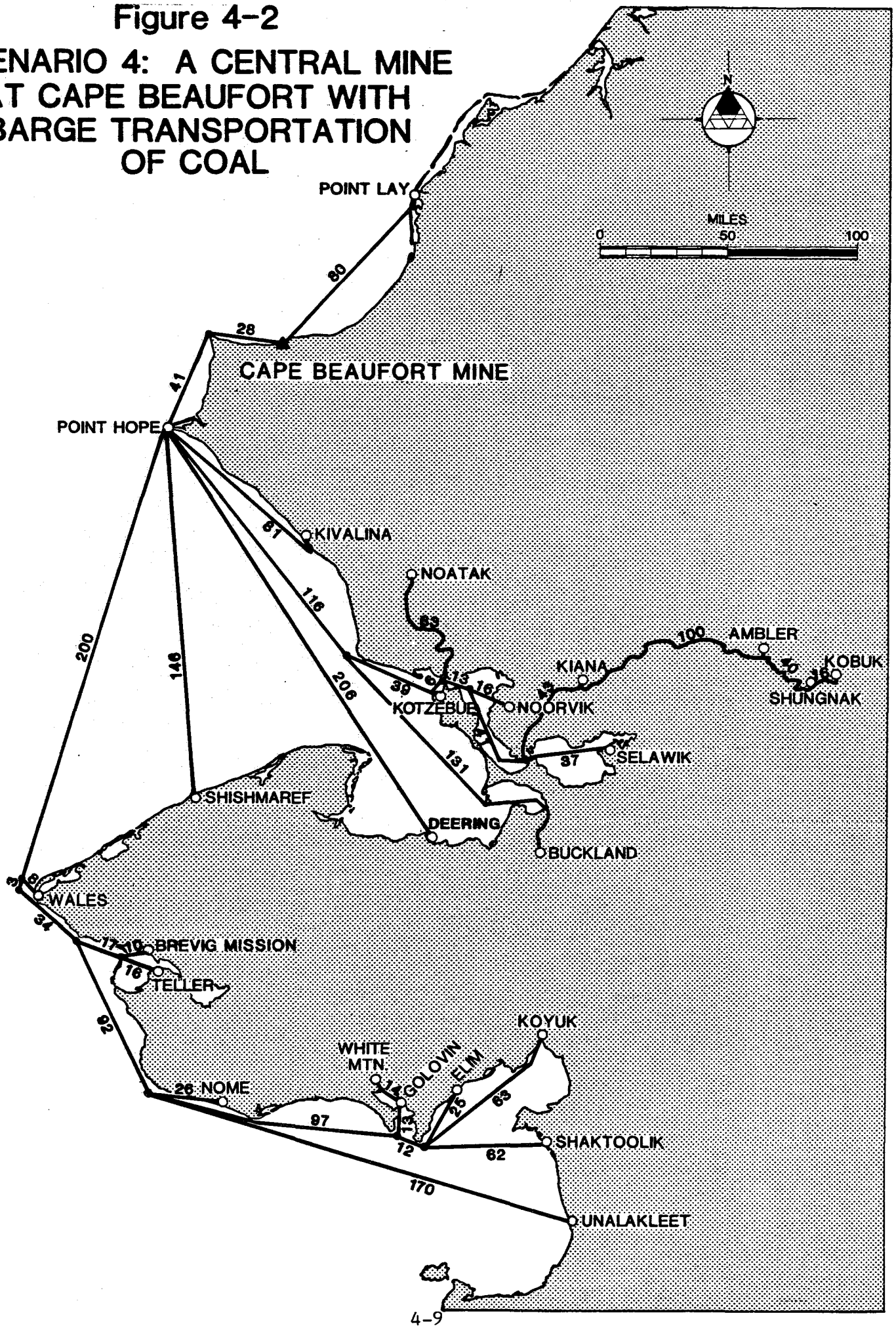


TABLE 4-2

SCENARIO 4:
BARGE TRANSPORTATION COSTS FOR
COAL DISTRIBUTED FROM CAPE BEAUFORT MINES

<u>Community</u>	<u>Distance (Statute Miles)</u>	<u>Cost/Trip (\$1000)</u>	<u>Cost/Ton (\$)</u>	<u>Cost/Million BTU (\$)</u>
Ambler	427	80.5	161	7.00
Brevig Mission	323	64.3	128	5.56
Buckland	316	63.1	126	5.56
Deering	275	56.7	113	4.91
Elim	495	92.2	184	8.00
Golovin	472	87.9	176	7.65
Kiana	327	64.9	130	5.65
Kivalina	150	36.3	73	3.17
Kobuk	483	89.9	180	7.82
Kotzebue	224	48.2	97	4.22
Koyuk	533	98.4	197	8.56
Noatak	293	59.2	118	5.13
Nome	387	74.5	149	6.48
Noorvik	259	53.9	108	4.69
Point Hope	69	23.2	47	2.04
Point Lay	80	25.0	50	2.17
Selawik	321	63.8	128	5.56
Shaktoolik	532	98.3	197	8.56
Shishmaref	216	46.9	94	4.09
Shungnak	467	87.0	174	7.56
Teller	327	64.9	130	5.65
Unalakleet	531	98.2	196	8.52
Wales	269	55.5	111	4.83
White Mtn.	486	90.5	181	7.87

Source: Interpolated from Table 3-2.

Figure 4-3

SCENARIO 5: A CENTRAL MINE AT CHICAGO CREEK WITH BARGE TRANSPORTATION OF COAL

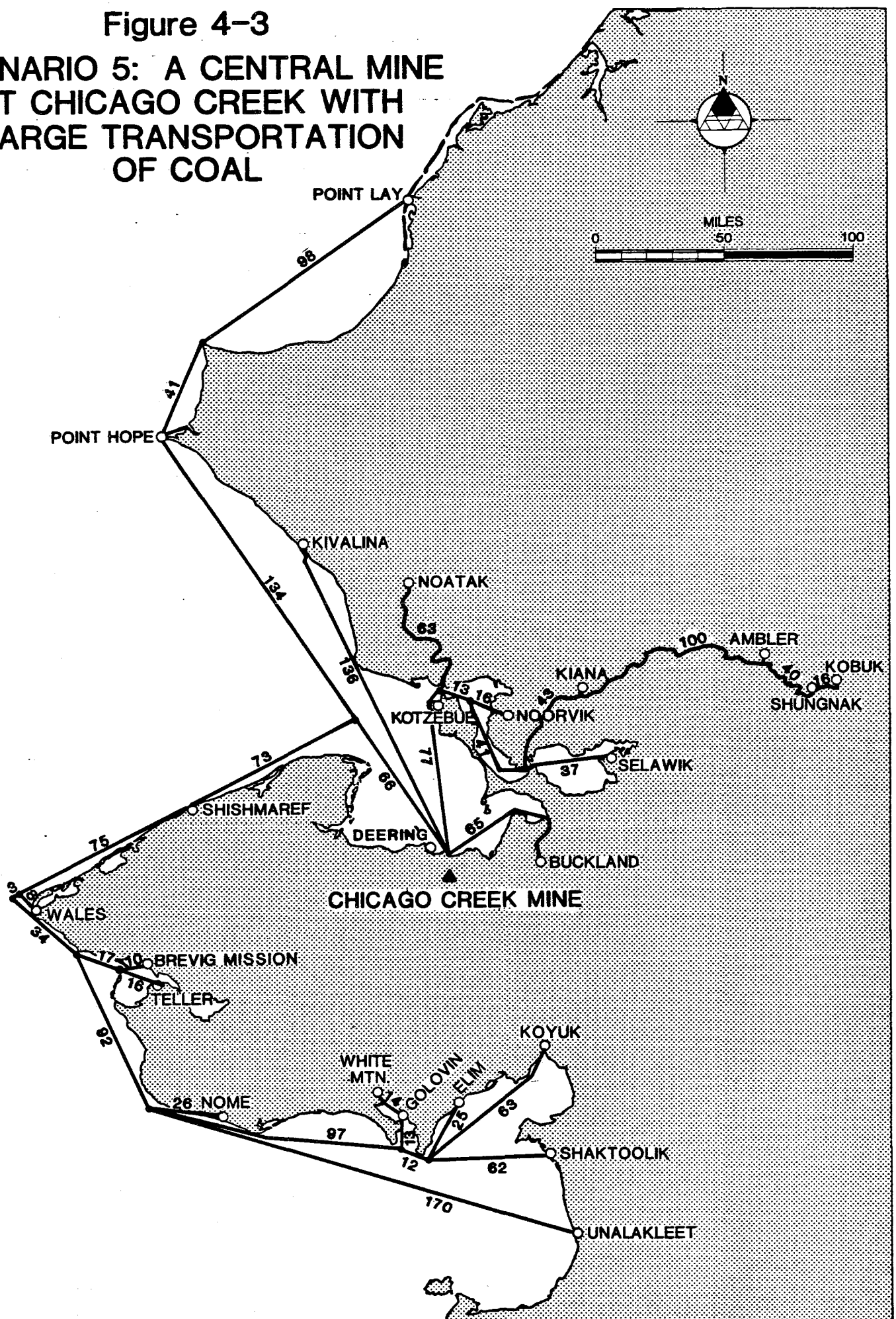


TABLE 4-3

SCENARIO 5: BARGE TRANSPORTATION COSTS FOR
DISTRIBUTION OF COAL MINED FROM CHICAGO CREEK

<u>Community</u>	<u>Distance (Statute Miles)</u>	<u>Total Cost/Trip (\$1000)</u>	<u>Total Cost/Ton (\$)</u>	<u>Cost/Million BTU (\$)</u>
Ambler	278	56.9	114	8.77
Brevig Mission	278	56.9	114	8.77
Buckland	65	22.6	45	3.46
Deering	10	13.6	27	2.07
Elim	477	89.2	178	13.69
Golovin	453	84.5	169	13.00
Kiana	180	41.1	82	6.31
Kivalina	136	30.7	61	4.69
Kobuk	334	66.0	131	10.08
Kotzebue	80	25.0	50	3.85
Koyuk	515	95.5	191	14.69
Noatak	146	35.6	71	5.46
Nome	369	71.6	143	11.00
Noorvik	115	30.6	61	4.69
Point Hope	200	44.3	89	6.85
Point Lay	339	66.8	134	10.31
Selawik	174	40.1	80	6.15
Shaktoolik	514	95.4	191	14.69
Shishmaref	139	34.5	69	5.31
Shungnak	318	63.3	127	9.77
Teller	284	57.9	116	8.92
Unalakleet	513	95.2	190	14.61
Wales	222	47.9	96	7.38
White Mtn.	467	87.0	174	13.38

Source: Interpolated from Table 3-2.

TABLE 4-4

COAL DEMAND BY SCENARIO AND SOURCE OF SUPPLY (TONS)

<u>Scenario/Description</u>	<u>Source Coal Deposits</u>				<u>Cape Beaufort</u>	<u>Total Coal Production</u>
	<u>Chicago Creek⁽¹⁾</u>	<u>Kallarichuk River- Kobuk River</u>	<u>Ambler River</u>	<u>Kogoluktuk River</u>		
1.0 Regional						
1.1 Kiana-based power plant	18,309	14,253	454	656		33,672
1.2 Kotzebue-based power plant	35,466	3,112	454	656		39,688
2.0 Sub-Regional						
2.1 Kotzebue alone	32,309					32,309
2.2 Kiana-based power plant serving Kiana, Noorvik, and Selawik		4,536				4,536
2.3 Ambler-based power plant serving Ambler, Shungnak, and Kobuk			1,736			1,736
3.0 Local						
3.1 Kiana alone		988				988
3.2 Ambler alone			719			719
3.3 Noorvik alone		1746				1746
3.4 Selawik alone		1802				1802
3.5 Shungnak alone				770		770
3.6 Kobuk alone				247		247
3.7 Kotzebue alone	32,309					32,309
4.0 Central Mine at Cape Beaufort					56,285	56,285
5.0 Central Mine at Chicago Creek	86,678					86,687

Source: Table 1-2

(1) Coal from Chicago Creek is of lower heat value (6500 Btu/lb); therefore tonnages from Table 1-2 have been increased here by a factor of 1.54.

Table 2-2 was used in selecting the coal occurrences assumed to supply each subscenario. The criteria used were likelihood of occurrence and proximity to community served. In the absence of firmer geological data, the existence of sufficient quantities available in surface mineable form was assumed.

Mining costs are based on the economies or diseconomies of scale for the amount of coal taken from a given occurrence in the context of the subscenario. Mining costs were allocated between electric generation and direct burned space heat in proportion to the respective tonnages used for each end-use, in each subscenario. Costs of mining are obtained by interpolation of Table 2-5.

Transportation Modes: Land transportation modes for coal were chosen where distances were less than 20 miles. Barges were used for longer distances.

The annualized total cost for haul road is assumed to be \$14,500. The total tonnage hauled over each road was calculated for each subscenario, then allocated between coal space heat and electricity based on the proportion of tonnage used. The figures used are obtained from Table 3-6.

Barge transport costs were based on days needed to deliver the required quantity of coal for the subscenario. It is assumed that the barges and tugs will be used in other service for up to 180 days a year. Annual costs were allocated on the basis of a 180-day year. Barge transport costs as a function of distance are shown on Table 3-2. Specific costs are obtained by interpolation.

Vehicle Use: The selection of road vehicles used to transport coal was based on the total quantity mined at a given occurrence in each subscenario and the road distance to the community in which it is used. The mode for this scale of operation was read from Table 3-5. Cost per ton-mile for owning and operating this vehicle mode were read off Table 3-6. Where distance and/or tonnages fell between the quantities specified on the table,

the mode with the higher cost was used. This assumption reflects the inevitable underutilization of vehicles that necessarily occurs when vehicles are used in remote areas. The same set of vehicles are then assumed to transport coal to all the communities served by a given mine for the specified subscenario. The ton-miles for coal space heat and electricity are calculated separately, then multiplied by the cost per ton mile.

Generating Plant and Transmission Lines: The costs associated with electric generating plants are interpolated from Table 1-3. As discussed in Section 1.6, transmission lines cost \$150,000 per mile to install, with an ownership cost of \$7,320 and a maintenance cost of \$10,000 per mile.

In all subscenarios, costs for 69 KV three-wire, three-phase overhead transmission lines were used. Although in some subscenarios lower voltages may be adequate, the cost differential would probably be insignificant. Line losses are reflected by increasing the cost per KWH by 5 percent for the subregional generating plants (Scenario 2) and 10 percent for the regional plants (Scenario 1).

Economic Assumptions: Annual capital charges and operating costs have been estimated in 1981 dollars to allow comparison of the three scenarios and their subscenarios. Component costs that have been built into this analysis are based on readily available reference material described in conjunction with the cost data developed in previous sections. Clearly, these "broad brush" cost data can only be relied upon to provide order of magnitude estimates. Hard engineering costing would be required to develop cost estimates with sufficient back-up to demonstrate true real world feasibility. Still, this analysis is instructive because: (1) it allows contrasts among the postulated scenario options; and (2) it reveals which scenarios may have sufficient merit to explore further.

The analysis relies on Alaska Power Authority (APA) assumptions for the critical discount rate and inflation parameters:

Discount rate = 3 percent
 Inflation rate = 0 percent
 Petroleum fuel escalation = 3.5 percent

The assumptions are more sensitive to the calculated values of the analysis than the underlying component costs. For instance a 10 percent discount rate to include a 7 percent risk premium compared to APA's risk-free 3 percent discount rate raises the annual capital charge for a 20-year project 75 percent. Including 7 percent general inflation as well as 10 percent discount rate raises the annual levelized cost of operating costs 55 to 75 percent over that based on 3 percent discount and 3.5 percent escalation of only petroleum products.⁽¹⁾ Hence, comparisons between the calculated coal-fired power costs and extant diesel-generated costs can only be made using identical assumptions.

Annual capital charges are estimated with a standard year-end capital recovery factor (CRF) assuming no taxes, zero inflation, and 3 percent discount rate. Time of investments is ignored, except for transmission lines which are assumed built over 4 years.

$$CRF = \frac{.03(1.03)^n}{1.03^n - 1}$$

where n = Life of Asset	CRF (see below)
20 = Coal Mines	.05102
30 = Power Plant	.0488
30 = Transmission Lines	.0672
30 = Roads	.05102
30 = Barge Transport	.1172
10 = Road Vehicles	

(1) The annual capital recovery charge for each \$1000 of investment at 10 percent is \$117.46; at 3 percent, it is \$67.22. The levelized cost per \$100.00 of inflating operating costs is \$163.65 at 3%/3.5%; \$206.50 at 10%/7%. These calculations are based on EPRI (1978).

The open pit mine annual capital charge is estimated from data on Table 2-5. Front-end investment cost is then capitalized with a 10 percent discount rate over 20 years. Ten percent reflects private ownership. Tax considerations and working capital are ignored.

Operating costs of vehicles and barge traffic are levelized for petroleum fuel escalation. All other component costs assume zero escalation.

4.4 A SIMPLIFIED SCENARIO ANALYSIS METHODOLOGY

Costs associated with the first two scenarios are obtained as shown in the tables in Appendix V. These scenarios are rather complex as they encompass coal from more than one mine and serve more than one community.

Costs for Scenarios 3, 4, and 5 are composed of single-mine sources and treat each community's costs separately. It was, therefore, possible to develop a simplified method for calculating the cost per ton and cost per kilowatt-hour for each community in these simple scenarios. A work-sheet for using this method is given in Figure 4-4. By filling in the specified information and working through the indicated calculations, the reader may evaluate the feasibility of any coal source for any community in the study area.

This method should prove useful if, on the basis of the forthcoming coal exploration program, occurrences other than those analyzed in this study appear to be promising.

Figure 4-5 shows an example of a completed work-sheet used to calculate the cost of coal and electricity for Ambler under Scenario 5.

4.5 ECONOMIC RESULTS

The economic analyses of the costs for providing coal for direct burned space heat and for providing coal-fired electric power are summarized in Tables 4-5 and 4-6. The detailed work sheets used to calculate these results are on file at the Alaska Power Authority offices in Anchorage.

FIGURE 4-4

SIMPLIFIED SCENARIO ANALYSIS WORKSHEET

SCENARIO _____
COMMUNITY SERVED: _____

Percent Electrical Space Heat ____ 10% ____ 50%

Specify:

A = ____ tons: Total tonnage mined at source =

B = ____ tons: Tonnage used in subscenario (Table 1-2)

C = ____ %: $B \div A$

D = ____ miles: Miles of mine haul road.

E = ____ miles: Barge distance from mine.

F = ____ BTU/lb: Heat value of coal mined.

G = ____ KWH: Electrical useage in subscenario (Table 1-2).

H = ____ miles: Transmission line.

I = ____ tons: Tonnage used for electricity (Table 1-2).

Cost per Ton

K = ____ mining cost per ton:

1. Enter Table 2-5 with A.
2. Interpolate cost per ton for actual tons mined. If A is greater than 60,000 use \$41.60 per ton.

L = ____ Road cost per ton:

$$1. L = \frac{C \times D \times 14,500}{A}$$

M = ____ Barge cost per ton

1. Interpolate from Table 3-2.

N = ____ Vehicles cost per ton:

1. Enter Table 3-6 with A and D.
2. Round A & D down to closest tonnage and distance on table.
3. Read off total cost per ton - mile.1
4. $N = \text{cost/ton-mi} \times D.$

FIGURE 4-4 (Continued)

O = _____ Cost per ton:

$$1. O = (K+L+M+N) \times \frac{10,000}{F}$$

Cost per KWH

P = _____ MW. Size of power plant.

$$1. \text{ For 50\% electric space heat } P = \frac{\text{KWH}}{4,380,000}$$

$$2. \text{ For 10\% electric space heat } P = \frac{\text{KWH}}{5,256,000}$$

R = _____ Cost of power plant.

1. Enter Table 1-3 with P.
2. Interpolate.

T = \$ _____ Cost of transmission lines.

$$1. T = 17,320 H$$

U = \$ _____ Cost of coal for electricity.

$$1. U = I \times O$$

W = _____ Cost per KWH

$$1. W = \frac{(R + T + U)}{G}$$

FIGURE 4-5

EXAMPLE WORK SHEET

SCENARIO 5

COMMUNITY SERVED: Ambler

Percent Electrical Space Heat X 10% 50%

Specify:

A = 56285 tons: Total tonnage mined at source =

B = 454 tons: Tonnage used in subscenario (Table 1-2)

C = .008 %: B ÷ A

D = 16 miles: Miles of mine haul road.

E = 278 miles: Barge distance from mine.

F = 6500 BTU/lb: Heat value of coal mined.

G = .39x10⁶ KWH: Electrical useage in subscenario (Table 1-2).

H = 0 miles: Transmission line.

I = 265 tons: Tonnage used for electricity (Table 1-2).

Cost per Ton

K = 42.33 mining cost per ton:

1. Enter Table 2-5 with A.
2. Interpolate cost per ton for actual tons mined. If A is greater than 60,000 use \$41.60 per ton.

L = .033 Road cost per ton:

1. $L = \frac{C \times D \times 14,500}{A}$

M = 114 Barge cost per ton

1. Interpolate from Table 3-2.

N = 4.16 Vehicles cost per ton:

1. Enter Table 3-6 with A and D.
2. Round A & D down to closest tonnage and distance on table.
3. Read off total cost per ton - mile.1
4. $N = \text{cost/ton-mi} \times D.$

FIGURE 4-5 (Continued)

O = 247 Cost per ton:

$$1. O = (K+L+M+N) \times \frac{10,000}{F}$$

Cost per KWH

P = 0.07 MW. Size of power plant.

$$1. \text{ For 10\% electric space heat } P = \frac{\text{KWH}}{5,256,000}$$

R = 379 Cost of power plant.

1. Enter Table 1-3 with P.
2. Interpolate.

T = \$ 0 Cost of transmission lines.

$$1. T = 17,320 H$$

U = \$65.455 Cost of coal for electricity.

$$1. U = I \times O$$

W = \$1.13 Cost per KWH

$$1. W = \frac{(R + T + U)}{G}$$

TABLE 4-5
SUMMARY OF COSTS OF COAL AND ELECTRICITY
FOR SCENARIOS 1, 2 & 3 (THE KOTZEBUE-KOBUK REGIONS)

<u>Scenario/Description</u>	<u>Electricity \$/KWH</u>	<u>Direct Heat \$/Ton</u>	<u>Total Annual Energy Cost⁽¹⁾ (\$1000)</u>
1.0 Regional			
1.1 Kiana-based power plant	0.56	190	12,200
1.2 Kotzebue-based power plant	0.66	209	14,139
2.0 Sub-Regional			
2.1 Kotzebue alone	0.20	191	4,935
2.2 Kiana-based power plant serving Kiana, Noorvik, and Selawik	0.96	152	2,470
2.3 Ambler-based power plant serving Ambler, Shungnak, and Kobuk	1.90	362	2,149
3.0 Local			
3.1 Kiana alone	1.11	334	708
3.2 Ambler alone	1.16	283	580
3.3 Noorvik alone	0.53	101	555
3.4 Selawik alone	0.48	115	540
3.5 Shungnak alone	1.14	285	597
3.6 Kobuk alone	3.18	411	480
3.7 Kotzebue alone	0.20	191	4,935

⁽¹⁾ Cost per KWH x KWH demand plus space heat coal cost per ton x space heat tonnage demand.

TABLE 4-6
SUMMARY OF COST OF COAL AND ELECTRICITY
FOR ALL COMMUNITIES IN THE STUDY AREA

	Scenario 4			Scenario 5		
	\$/KWH	\$/Ton ⁽¹⁾	Total Annual Energy Cost (\$1000) ⁽²⁾	\$/KWH	\$/Ton ⁽¹⁾	Total Annual Energy Cost (\$1000) ⁽²⁾
Ambler ⁽³⁾	1.09	177	505	1.13	247	552
Brevig Mission	1.45	148	447	1.52	247	494
Buckland	1.07	146	462	1.06	141	466
Deering	1.02	135	442	1.00	107	429
Elim	1.32	197	494	1.42	346	581
Golovin	1.65	190	459	1.75	332	520
Kiana ⁽³⁾	0.98	150	525	1.01	198	571
Kivalina	0.94	115	475	0.97	165	514
Kobuk ⁽³⁾	3.04	193	426	3.09	273	446
Kotzebue	0.14	121	3,303	0.16	150	3,913
Koyuk	1.33	208	502	1.43	365	593
Noatak	0.90	139	513	0.93	180	553
Nome	0.17	166	3,207	2.60	292	5,235
Noorvik ⁽³⁾	0.55	131	606	0.58	166	672
Point Hope	0.54	77	495	0.63	208	691
Point Lay	1.63	80	412	1.77	278	497
Selawik ⁽³⁾	0.56	148	647	0.59	195	729
Shaktolik	1.16	208	505	1.28	365	606
Shishmaref	0.72	118	468	0.76	178	580
Shungnak ⁽³⁾	1.07	188	521	1.10	267	572
Teller	0.83	150	507	0.89	250	590
Unalakleet	0.33	207	1079	0.43	364	1,589
Wales	1.44	133	451	1.50	219	498
White Mountain	1.77	194	460			
TOTAL			(17,911)			(21,891)
Subtotal, Kotzebue- Kobuk Region			(6,533)			(7,455)

⁽¹⁾ All costs per ton are expressed in 10,000 Btu per pound coal equivalents.
The costs are adjusted by this factor: $\frac{10,000\text{Btu/lb}}{\text{Actual Btu/lb}}$

⁽²⁾ Cost per KWH x KWH demand plus space heat coal cost per ton x space heat tonnage demand.

⁽³⁾ Communities in the Kotzebue-Kobuk Region.

Source: Dames & Moore

4.5.1 Delivered Cost of Coal

The delivered cost of coal (adjusted for heat content⁽¹⁾) ranges from \$80 to \$411/ton equivalent depending on coal source and scenario. To understand the wide cost discrepancy, it is instructive to examine the extreme cases.

The \$80 coal refers to Scenario 4 where Cape Beaufort coal is transported to Point Lay. Most of the cost (\$44/ton-equivalent) is due to the 80-mile barge link. No road transport is needed. The remaining \$36/ton equivalent represents mining costs. Since in Scenario 4, coal for the entire study area is mined centrally, the maximum economics of scale are realized. The high Btu content of Cape Beaufort coal (approximately 11,500 Btu/pound) is reflected in the above numbers by reducing both the amount of coal mined and the amount transported for producing a given amount of heat.

The \$411/ton-equivalent coal is for Kobuk under Scenario 3. Although coal for Kobuk is mined only six miles away, a road must be constructed and maintained to provide only 247 tons per year. This road alone drives up the cost by \$352 per ton-equivalent. The remaining cost is for mining at a small, therefore less economic, scale. The cheapest coal for Kobuk is provided in Scenario 4, where it is barged 483 miles from Cape Beaufort, at a cost of \$180/ton. This results in a \$193 cost per ton-equivalent.

The comparison of coal costs under the five scenarios illustrates several trends. Barging coal, even for relatively long distances, is feasible. Despite conservatively high assumptions for cost per day, and low assumptions for daily distance traveled, barge transportation costs never exceed \$197 per ton (533 miles from Cape Beaufort to Kobuk). The barge approach also enables all communities to share in the economies of scale in mining at a central location. It also permits all communities to make use of

(1) All reported costs per ton are in terms of 10,000 Btu/pound equivalents. Actual costs for lower Btu coals (such as lignites) are thus raised while higher grade coal costs are lowered, by the factor 10,000/Btu.

the better rank coals, thus lowering the cost for an equivalent number of Btu's. This combination of effects is the reason that coal cost is uniformly lowest under Scenario 4.

Looking at Table 4-6, coal costs in Scenario 4 are as high as \$208 for Koyuk and Shaktoolik, which are more than 500 miles from the coal source. Even at this distance, coal use is cheaper than diesel for even these communities. Assuming a 3 percent annual escalation factor, diesel now costing \$1.50 per gallon delivered in the study area will cost \$2.60 in year 2000. On the basis of heat content, this can be equated to coal at \$400 per ton. Thus, coal is cost effective by almost a factor of 2. Even if the cost of purchasing stoves to burn coal were factored into this analysis, it is feasible to use coal throughout the study area.

4.5.2 Cost of Coal-Fired Electricity

Cost of coal-fired electricity is a function of cost of coal as well as the amount of electricity used. This causes the cost per KWH to range between \$3.18 for Kobuk (Scenario 3) and \$0.14 for Kotzebue under Scenario 4. Kobuk suffers from both high cost coal and low electric utilization, primarily the latter. At the assumed minimum annual cost for a coal-fired generator of \$303,000, \$2.33 per KWH of Kobuk's electricity cost is accounted for by generation. This effect explains the high electricity costs for small communities in Scenario 3, 4 and 5.

In Scenario's 1 and 2, the diseconomies of small power plant generation are avoided. The cost per KWH for the Kotzebue-Kobuk region ranges from \$0.66 to \$0.56 in Scenario 1, depending on coal source. However, if this cost were charged uniformly throughout the region, the small communities like Kobuk would be subsidized by the large communities like Kotzebue. This is evident from the low cost for electricity for Kotzebue alone (Subscenario 3). Transmitting power over long distances raises the cost of electricity tremendously, outweighing the savings from central generation. This can be seen by comparing the total annual cost for providing heat and electricity for the region among Scenarios 1, 2, and 3. This cost ranges from \$12.2 million (for

Subscenario 1.1) to \$9.55 million (for total of Subscenarios 2.1, 2.2 and 2.3) to \$8.4 million (for Subscenarios 3.1-3.7). Despite generation cost savings, local power generation remains less costly than regional or sub-regional generation.

As seen from Table 4-6, Scenario 4 produces the lowest cost electricity, primarily because high grade coal (11,500 Btu/pound) is assumed available at Cape Beaufort. However, even in Scenario 4, electricity costs are high for most communities.

According to APA, diesel-based electricity now costs about \$0.35 per KWH in the small communities. On the basis of Tables 1-1 and 1-2, about 3.2 million gallons of diesel would be used for electricity (22.7 million KWH) alone (no space heat) in year 2000. At a current cost of \$1.50 per gallon (delivered) and escalation of 3 percent per year, diesel will cost \$2.60 per gallon by year 2000. The cost for diesel alone will then amount to \$0.37 per KWH. Allowing another \$0.13 per KWH for operation, maintenance, and ownership costs, electricity will cost \$0.50 per KWH. Only three communities--Kotzebue, Nome, and Unalakleet--can produce electricity for a cost less than \$0.50 per KWH. It appears that coal-fired power generation is feasible for these larger communities, but not feasible for the remaining smaller communities. However, the three communities for which coal generation is feasible account for 74 percent of electric usage in year 2000.

In conclusion, according to the cases analyzed, central mining of high BTU coal with barge distribution is feasible for replacing all diesel space heating needs, and 74 percent of the electrical needs of the study area.

4.6 ACTION RECOMMENDATIONS

It will be feasible to replace 90 percent of existing diesel needs with coal, assuming that the local coal reserves prove out. If the \$7.3 million dollars now spent on imported diesel can be retained in the local economy, a significant step toward regional economic independence will have been taken. To bring coal use into reality, the following actions in order of importance are recommended:

1. Coal Occurrences: Those coal occurrences which are at or within 30 miles of the coast, are mineable by surface methods, and which have a heat value of at least 10,000 Btu should be explored. These areas are presented in Table 4-7.
2. Mine Ownership: The ownership status and regulatory complexity of surface mining at the promising occurrences should be determined. These factors may significantly influence the site selection.
3. Electric Utilities: The electric utilities at Kotzebuk, Nome, Noorvik, Selawik, Point Hope and Unalakleet should be advised of the potential feasibility of coal-fired generation.
4. Social Acceptance: The social acceptability of home coal use should be evaluated. Potential users should be made aware of the availability of efficient coal and wood stoves.
5. Electrical Generation: Small coal-fired power plants for the majority of villages do not appear feasible. Cost per single units would be high since, although the technology exists, it is no longer commercially available. The cost of small coal-fired steam turbine plants should be determined based on bid solicitation for a 100 to 200-KW plant on a turn-key basis (designed, fabricated, delivered, and installed). The cost may be considerably lower than that reported in this study if a bulk order (more than 10 units) is tendered. Units would require minimal maintenance, automatic shut-down (for unattended operation), a semi-automatic feed, and freeze protection in case of shut-down. The possibility of district heating (using waste heat from the power plant) should be evaluated as well.

TABLE 4-7

RECOMMENDED AREAS FOR FURTHER EXPLORATION

<u>Exploration Priority</u>	<u>Area⁽¹⁾</u>	<u>Comments</u>
1.	Point Lay (Areas 2A, B, C) Upper Kukpowruk River	High thickness of total coal (especially Area 2C with 20-foot bed) and relatively low dips (6 - 20 degrees) make stripping ratios favorable.
2.	Deadfall Syncline (Area 6) About 30 miles south of Point Lay, along Cape Beaufort	Coal up to 15 feet thick drilled in low-dip area within 20 feet of surface. Drilling data available.
3.	Point Lay (Area 1B) Lower Kukpowruk River	Total coal is 18 feet, but with dips of 30 - 40 degrees; unfavorable stripping ratios.
4.	Corwin-Thetis (Area 8) Lower Cape Beaufort cliffs about 80 miles southwest of Point Lay.	Corwin least desirable because of very high dips; with max dip of 24 degrees at Thetis area, stripping ratio unfavorable because of low total coal thickness recorded (10 feet).

⁽¹⁾Refer to Plate 1 of Phase I report, Volume II.

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APPENDIX I

APPENDIX I

TRANSMISSION SYSTEMS

DC SYSTEM

Basic DC transmission systems are either monopolar and bipolar. The monopolar DC transmission system uses a single transmission line conductor with a ground return to complete the circuit. The bipolar DC transmission system uses two transmission line conductors. Current normally flows through the conductors but ground electrodes are also required for unbalanced current flow.

Transmission costs and adverse visual impacts are minimized with a monopolar system; however, reliability is less with only a single line. The monopolar system requires converters for a single pole. Reliability is increased with a bipolar system since the ground becomes a circuit path when one line is lost. Line costs and the visual impact for the bipolar system are more than for a monopolar system. The bipolar system requires converters for two poles at each termination.

Modern technology has reduced converter station costs associated with DC systems, but power must be transmitted long distances to justify the total system costs. That is, the savings in reduced cost of the transmission system must be great enough to offset the additional cost for the converters at the terminal stations.

AC SYSTEM

AC transmission systems investigated for this study included single-phase and three-phase systems. The single-wire ground return AC system (SWGR) offers many of the same advantages as the monopolar DC system. At this time, however, the National Electric Code does not approve this type

of a system. Single-wire construction also offers lower construction costs and less adverse environmental impacts than a conventional three-phase AC system.

Disadvantages of the conventional three-phase system include the limited distances power can be transmitted due to system losses, and charging current problems. A low frequency single-phase AC system could reduce losses and charging current; unfortunately, the technology has not been advanced in this area. Other problems are inherent with generating power in the conventional three-phase AC voltage and then transmitting power at single-phase AC. These problems could be avoided with a single-phase generator. It was found, however, that a single-phase generator may be very difficult to obtain.

Possible types of AC three-phase transmission construction include overhead transmission line, underground transmission line and submarine cable. Factors affecting the type of construction are transmission route, environmental impact, construction and operation costs, and reliability (from the standpoint of comparative down time during troubleshooting).

Overhead construction would probably consist of a single wood pole with cross-arms and ACSR conductor. Advantages for overhead construction are low initial installation cost and subsequently small maintenance costs. Potential adverse impacts of overhead construction in remote areas can be lessened with the aid of helicopters for construction. Disadvantages inherent in overhead construction are possible adverse visual impacts, other adverse environmental impacts that could occur such as right-of-way clearing, and lowered reliability due to exposure to the elements. The severe wind and ice of the study area could cause mechanical loading problems for overhead transmission lines. Most of the disadvantages of overhead transmission lines can be minimized, however, through good design procedures.

Underground construction would be anticipated to include a 35-kV, solid, di-electric shielded, direct burial cable. Excavation material could also serve as backfill material and minimize the need to establish quarries. Line reliability could be higher for buried cable than for overhead construction

since the line could not be exposed to as many adverse conditions. The adverse visual impacts of overhead lines would be eliminated. Disadvantages of underground cables include their high cost and difficult maintenance.

Submarine cables share the same advantages and disadvantages of underground cables. In addition, construction of submarine lines could create adverse impacts on salmon streams. Again, these problems and disadvantages can be reduced with careful construction, route planning and design.

CONCLUSIONS

Despite the cost advantages of single-wire and DC systems, Dames & Moore recommends the use of conventional three-wire, three-phase AC transmission lines. The remoteness of the area and the inaccessibility to technical support services in case of failure argues for the use of the most reliable and conventional system. These should be above ground for ease of access. The visual advantages of submarine or underground cables are more than offset by their adverse environmental impacts during construction, difficulty of access for repair and much higher capital cost. Costs for a three-wire transmission line in this area of Alaska in the last few years have ranged from \$80,000 - \$120,000 per mile. For this study, \$150,000 per mile is considered to be a reasonable estimate of three-wire transmission line costs given the area's remoteness. Annual operating and maintenance costs, based on the experience of other utility companies with comparable service areas, are estimated to be in the range of 5 to 15 percent. For the purposes of this study, an average value of \$10,000 per mile was assumed.

APPENDIX II

APPENDIX II

MINE MODELS

Small-Scale Surface and Underground Mines - Models 1-4 (100-5000 Tons Per Year)

In light of the demand data developed in Chapter 1.0, the coal demands of many individual communities are relatively small. Therefore, it is possible that the mines required to satisfy the limited demand of their communities also will be small. To account for this possibility, four small-scale mining operations were developed. The rates of production considered are 100, 500, 1000 and 5000 tons per year. Both open pit and underground mining methods were analyzed and the costs attendant with each assessed.

At these low mining production rates, it is likely that simple surface mining techniques would be employed due to economic considerations. Mining would be conducted along coal outcrops with a small hydraulic backhoe; the coal would be loaded onto a truck or wheeled tractor and trailer and hauled from the mine to the demand center.

In some instances underground mining at limited production rates could be carried out, and might be required in some locations, for example, in the Cape Lisburne and Cape Beaufort areas where the coal outcrops along the sea cliffs and where access might be from the sea. In such instances, small-scale underground mining might develop a mine at an annual rate of 5000 tons operating only during the summer months, six days per week.

Ideally, if limited underground mining is necessary, access to the coal would be by a short, horizontal drift along the strike of the coal bed. Where this would not be possible (for example, where the coal outcrops at the base of the cliff and dips into the cliff) an inclined access would be required. Rooms would be developed off the main strike drift. Coal would be

loaded into rail haulage cars by a small compressed air overhead loader. The rail track would be advanced toward the face after each cut to minimize travel distance for the loader. Alternatively, for the lower rates of production, a small wheeled tractor with a front bucket and trailer would be possibly used. In both these cases, some hand loading would be required for clean-up. If the coal dip was greater than the angle of repose, the coal could be stoped up-dip as in metal mining practice and gravitated down to a draw point where it would be loaded directly into haulage cars.

Larger Scale Surface Mines - Models 5-6 (10,000-60,000 Tons Per Year)

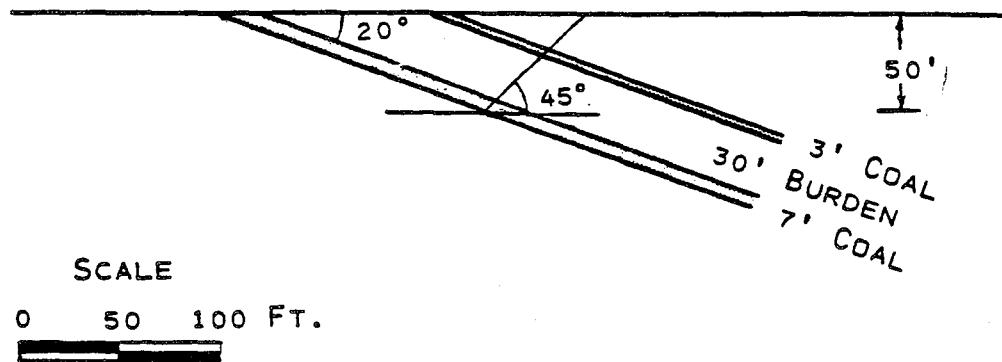
Due to the lack of detailed geological data in the study area and the great variety of geological situations likely to be encountered in such a vast territory, it would be outside the scope of this study to design specific mines for each area. Therefore, two geological models believed to be typical of the region were selected. Models 5 and 6 are hypothetical situations with moderately thin, moderately flat-dipping seams.

Surface Mine Model 5 (10,000 Tons Per Year)

Figure II-1 shows a cross section of mine Model 5 with two thin, moderately dipping seams. Dips are likely in most cases to be low, however, a 20 degree dip was factored here to be conservative and to show some stripping being required to expose the coal. With the budget likely to be available for exploration, it would be imprudent to expect that an ideal coal deposit (thick seams, very shallow dip, and, therefore, little stripping) would be found in the right location.

The same stripping ratio in this model could pertain in mining the same seam thicknesses at a shallower dip to the same depth, or mining thinner seams at a shallower dip to a smaller depth. This mine is designed for a production rate of 10,000 tons per year and is assumed to operate only for the three summer months on a six-day week basis. For such a small production rate it would not be economical to maintain access and all the backup facilities required for a year-round operation.

Figure II-1 Conceptual Surface Mine Model No. 5



COAL REQUIRED PER YEAR: 10,000 TONS

25 YEAR RESERVE: 250,000 TONS

RECOVERABLE SEAM THICKNESS: 3 & 7 FT.

SEAM DIP: 20°

STRIKE LENGTH: 1/2 MILE

PIT DEPTH: 50 FT.

PIT LENGTH: 1/2 MILE

COAL RESERVE: 125,000 TONS

STRIPPING RATIO: 2.8 YD³/TON

NUMBER OF PITS REQUIRED: 4

ASSUMPTIONS:

3 MONTH SUMMER OPERATION

NET DAYS PER YEAR: 78

8-HOUR SHIFTS PER DAY: 2

MAJOR MOBILE EQUIPMENT:

1-1 YD³ BACKHOE

4-5 TON TRUCKS

1-2 1 1/2" WAGON DRILL

1-350 CFM. COMPRESSOR

1-DOZER

The mining area would be long and narrow, following the outcrop of the coal seams. Rope or hydraulic diesel-powered shovels and rear dump trucks would be used for excavation. A dragline system could also be used and at lower operating costs, but it would be less flexible in terms of varying the production rate and stripping ratio. Trucks would still be required to haul the coal to the main transportation system. In mining in remote areas, the number of types of equipment should be kept to a minimum to reduce the spare parts inventory. It is assumed that drilling and blasting would be required in both waste stripping and coal removal. Airtrack drills and mobile diesel-powered compressors would be used for drilling. Explosives would be of the conventional ammonium nitrate/fuel oil and/or slurry type.

A deep cut would be made initially at one end of the mining area with benching at appropriate intervals. Waste would be dumped outside the mining area and close to the initial cut. Thereafter, following coal removal in the cut, the stripping program would advance away from the initial cut, the waste being progressively backfilled into the cut.

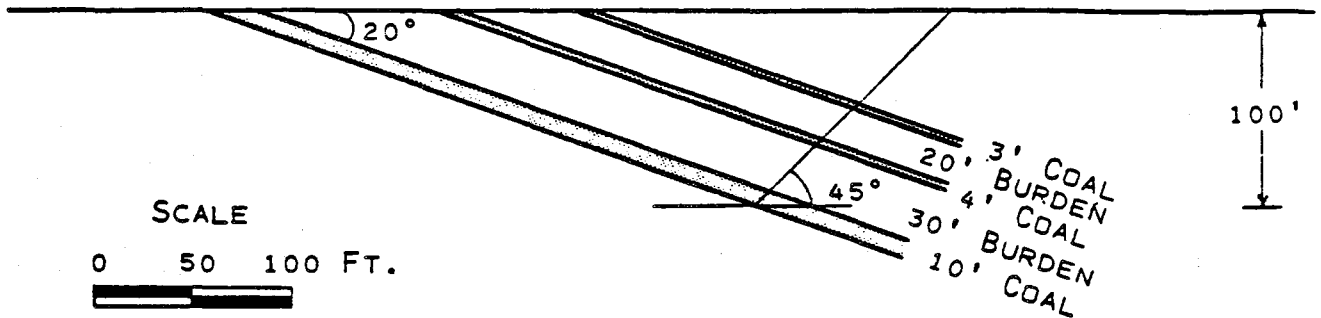
Note that the seam thicknesses shown on the figures are recoverable thicknesses. In fact, the recovery should be of the order of 85 to 90 percent.

Figure II-1 also shows the production rate and 25-year reserve, seam and pit dimensions, operating parameters, and major mobile equipment requirements. This equipment is based on mining at the average stripping ratio. Four such pits would be required to sustain a 25-year operation.

Surface Mine Model 6 (60,000 Tons Per Year)

Figure II-2 shows a cross section of mine Model 6. Model 6 would be similar to Model 5 but with more and thicker seams and a deeper pit. Model 6 is designed for a production rate of 60,000 tons per year in a year-round operation. The mining method would be the same as with Model 5 but would use larger equipment. As in Figure II-1, Figure II-2 shows seam and pit

Figure II-2 Conceptual Surface Mine Model No. 6



COAL REQUIRED PER YEAR: 60,000 TONS

25 YEAR COAL RESERVE: 1.5 MM TONS

RECOVERABLE SEAM THICKNESS: 3, 4 & 10 FT

SEAM DIP: 20°

STRIKE LENGTH: 1/2 MILE

PIT DEPTH: 100 FT.

PIT LENGTH: 1/2 MILE

COAL RESERVE: 0.4 MM TONS

STRIPPING RATIO: 3.5 YD³/ TON

NUMBER OF PITS REQUIRED: 4

ASSUMPTIONS:

ALL YEAR OPERATION

NET DAYS PER YEAR: 204

8-HOUR SHIFTS PER DAY: 2

MAJOR MOBILE EQUIPMENT:

1-2 1/2 YD³ SHOVEL

1-2 YD³ LOADER

6-12 TON TRUCKS

2-3" AIR-TRACK DRILLS

2-600 CFM. COMPRESSORS

1-DOZER

1-GRADER

dimensions, operating parameters and major mobile equipment. Four such pits would be required to sustain a 25-year operation.

Larger-Scale Underground Mines - Models 5-6 (10,000-60,000 Tons Per Year)

Two model underground mines have been designed at the same production rates as the surface mines described above. In both models, a year-round operation has been assumed inasmuch as it would not be prudent to abandon an underground mine for most of the year. In fact, there would be more reason to close the mine during the summer months than the winter months so that the warmer summer ventilation air would not melt the permafrost and reduce ground stability. The mine models are described as follows:

Underground Mine Model 5 (10,000 Tons Per Year)

A 5 to 7-foot-thick coal seam would be extracted. The seam dip would be zero to six degrees (10 percent). Rock below the seam is generally capable of supporting light traffic without rapid deterioration. Coal is anticipated to separate from the floor and roof readily. The roof ordinarily would need no support over a span of 15 feet for a period of several months. Beyond that time, localized deterioration of roof strength may require a moderate degree of support.

The coal reserve consists of a block averaging 6 feet in thickness, and is 1,760 feet on each side (a total of 71 acres containing 750,000 in-place tons). The initial mine plan is based on recovering one third of the in-place reserve (250,000 tons) over a period of 25 years at the rate of 10,000 tons per year. It is possible that a higher recovery rate is attainable, but conditions discussed make it prudent to set a conservative recovery goal at the outset.

Development of underground mine Model 5 is based on several principles:

- Extraction of the seam would start at the far corner of the coal block and progress toward the main portal, that is, in retreat. Once a room is complete, it should not be necessary to re-enter the room.
- A minimum number and length of mine development openings would be active at any given time.
- The mine would be divided into six areas, each of which would be capable of supplying about four years of coal. Each of these areas would be divided into three areas sufficient for about 1.4 years of production. The concept of focusing production on limited areas at any given time would be the goal of such divisions.
- Main entries would be driven along the centroidal axis of the coal block, very slightly updip from the strike to allow for drainage, if any, and to provide access to either side of the block.
- Mine development would consist of providing three entries to each production block and to the rooms within that block. One entry would be for intake air, another for exhaust air, and a third for passage of men and a conveyor.
- The mine would be operated for optimum worker safety and economy -- not for maximum recovery of coal.

Mine development would start by creating a portal work area and advancing the three entries along the centroidal axis of the block for about two-thirds the length of the block -- in this case, about 1,433 feet. The openings would be driven 10 feet wide with two intervening 50-foot pillars. At a later date, the entries could be widened to 15 feet, if necessary.

To produce 40 tons per day, each entry would need be advanced only 5.5 feet per day. The entries would be driven for two-thirds the strike length

of the coal block (1,173 feet), and would then turned updip for about one-third the width of the block (587 feet). Finally, the entries would be turned along strike again, and driven to the extremity of the block (587 feet). Mine development at this point of the sequence is shown on Figure II-3 (a); 427 work days (assuming one shift per day) would be necessary to reach this stage on development.

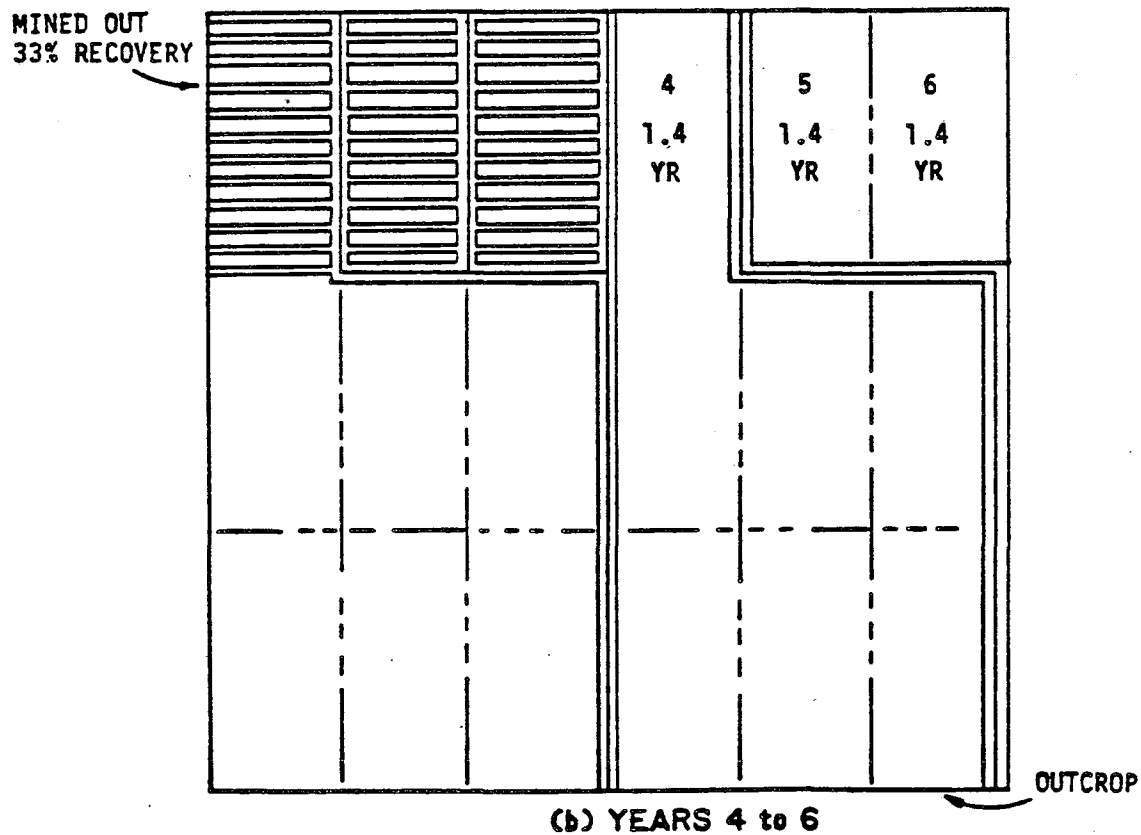
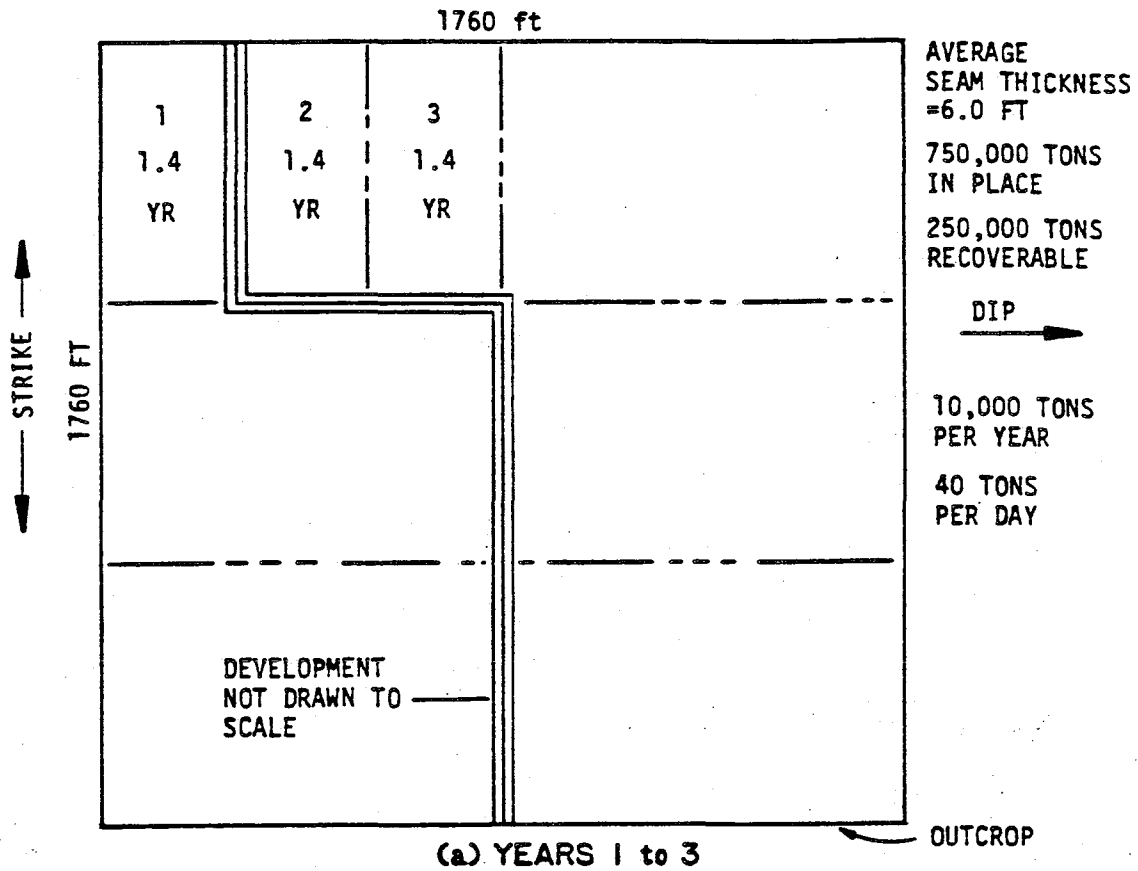
A portion of the coal in the extreme updip corner of the coal reserve block, sufficient to provide 40 tons per day for 1.4 years (17 months), would be exposed for routine production. The production sequence would consist of driving 15-foot-wide rooms on 45-foot centers at right angles to the entries and to the updip extremity of the reserve block. Each room, or set of two or three rooms, must be advanced a total of only 11 feet each day to produce 40 tons of coal.

Each 1.4-year portion of the reserve block would be extracted on retreat toward the portal and downdip. When the center of the reserve block is reached after about six years of mine operations, a second set of three entries would be driven along the downdip perimeter of the block, analogous to the first set. In this manner, there would always be a path for any drainage and coal could always move downgrade as shown in Figure II-3(b).

By following the principles and sequence outlined above, problems related to ground control would be minimized. It is absolutely essential that the mine operate in a manner to minimize the costly need for timbers, steel sets, roof bolts, and concrete linings. By minimizing open development, retreating away from worked-out areas, and leaving unfailing pillars in place, any adverse effects of permafrost or roof strata weaknesses should not hamper the safety or economy of mining operations.

Development openings, entries, and rooms would be created by the same procedure. A cut parallel to the dip of the coal seam would be made in the exposed face to a readily manageable depth (anticipated not to exceed 5.5 feet). The cut would be made by an electric-powered cutting machine capable of producing any orientation or practical depth of cut in a few minutes.

Figure II-3
Conceptual Underground Mine Layout Model No. 5



After the initial slot is created in the face, a simple pattern of holes would be drilled to the same depth using rotary auger drills. These holes would then be blasted. In a small mine, the coal could be hauled by a load-haul-dump (LHD) machine to the portal. When the mine is extended sufficiently underground that the use of a LHD unit is no longer economical, a light, small-capacity conveyor would be used to transport the coal from gathering points to the portal area.

Ventilation needs are simple. During initial development, air would be carried to the work face through vent pipes and flexible tubing and exhausted through the entry. When the first crosscut area is reached, however, ventilation circuits would be created to bring air in one entry, boost it to the face with movable fans and vent pipe, and then carry the contaminated air to the surface via a separate exhaust-air entry.

Underground Mine Model 6 (60,000 Tons Per Year)

All of the principles and conditions described for the 10,000-ton-per-year mine would also apply to this mine. The only significant differences are:

- Two areas in the far updip corner of the coal reserve block would be prepared for mining.
- The entries would be driven 10 feet wide and 6 feet high. To produce the required 240 tons per day during the mine development period, each entry would be advanced 33 feet per day on a two-shift-per-day basis. Each entry would require, therefore, three 5.5-foot cuts on each shift. Should this create a problem in maintaining production, a nearby updip area could be developed, and partially produced to take the strain off of the development headings.

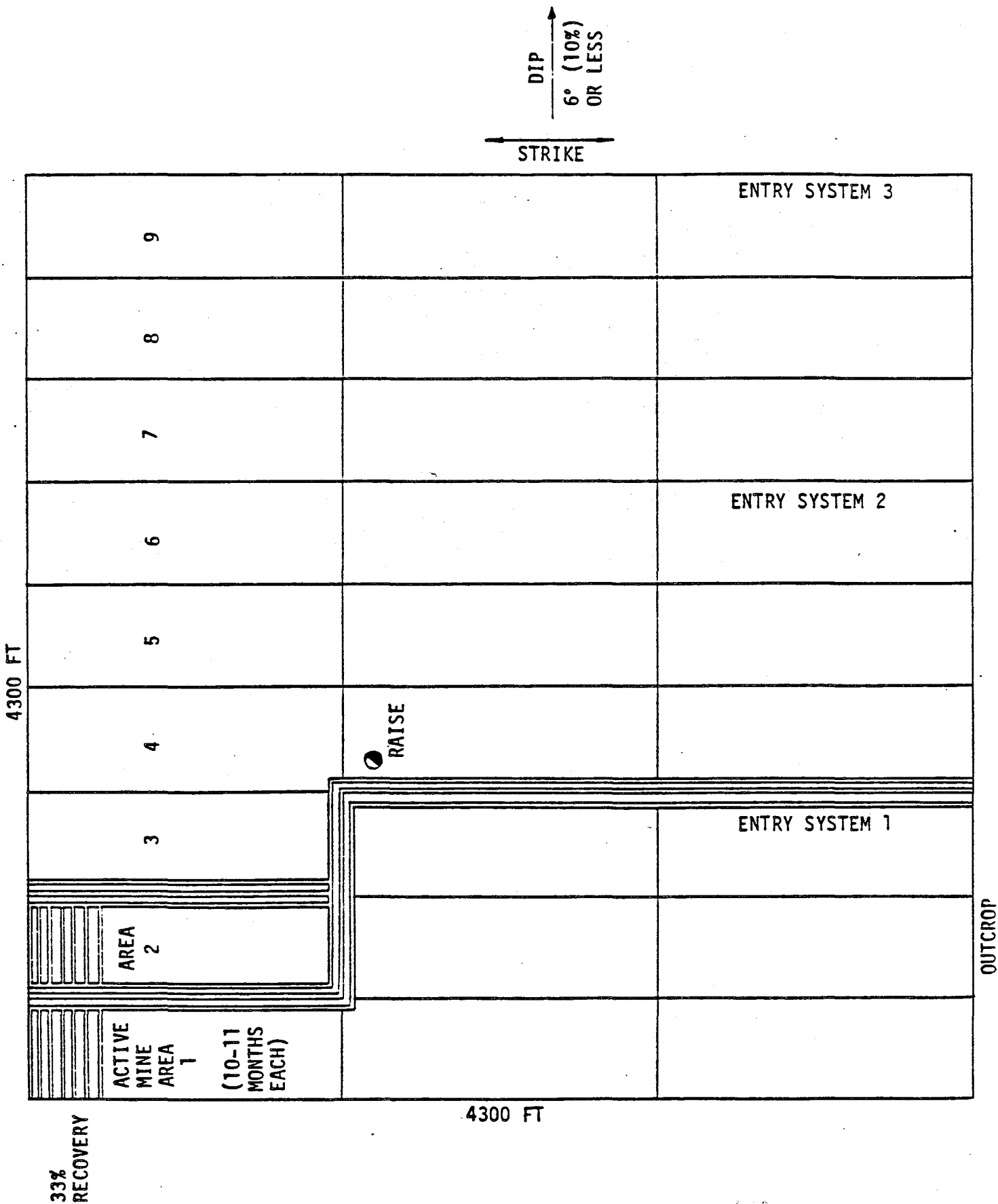
If the 33-foot-per-day schedule is maintained, however, 203 days would be required to outline the initial two production areas shown on Figure II-4. After that time, operations could be limited to one shift per day by advancing 15-foot rooms a total of 66 feet per day. For example, 12 rooms could be advanced 5.5 feet each day, or 6 rooms advanced 11 feet each.

- The area of the 25-year reserve is appreciable (425 acres), but it is not particularly large for a coal mine. Nevertheless, the operation and economics of the operation could benefit from careful placement of raises at various intervals if the conditions of driving the raise are not especially difficult. For example, the raise shown on Figure II-4 could be equipped to get men into the work area more quickly. If a second raise were positioned advantageously, a shorter ventilation circuit could be devised for the active mining areas, thus resulting in ventilation economy and possibly retarding deterioration of permafrost ground adjacent to the main entries.

This latter point may be more important in this 60,000-ton-per-year mine than in the 10,000-ton-per-year mine. It may not be as easy to avoid production during warmer summer months to prevent bringing warmer air into the mine and weakening permafrost structures.

Figure II-4

Conceptual Underground Mine Layout Model No. 6



APPENDIX III

Beyond the limits of temperature change, roof support problems appear to be minimal. Retaining the rock temperature, particularly in the -2 to -10°C range, obviates the need in many workings for roof support.

Ventilation

No evidence was found of efforts to chill external air before its entry into coal mines. Instead, roof support is provided in areas where warm air is introduced, hence, that are subject to thawing. In some Soviet coal mines, incoming mine air is heated when the external ambient air temperature is -20°C or lower in order to improve worker comfort underground. Some mines evidently also maintain above-freezing temperature in winter to facilitate the use of water for dust control. The short term effect of this practice does not appear to cause undue roof support problems, however, the long term effect may be serious. In some Soviet Arctic coal mines, this practice may contribute to increasing the chances of spontaneous ignition of underground coal, sudden roof collapse, and shaft deformation and cracking.

Coal mine ventilation requirements depend on government mine safety codes, which take into account worker safety and comfort, gas content, and dust content.

CONSTRAINTS ASSOCIATED WITH FROZEN WATER

By definition, rock temperatures in permafrost are below freezing. This fundamental fact indicates that water will freeze, and this in turn can cause extreme difficulties.

The use of large amounts of water for dust suppression will soak the coal which will then freeze. If it does not freeze underground, it will certainly freeze at the normal low winter

APPENDIX III

GEOTECHNICAL CONSTRAINTS

The following is quoted from the Mineral Industry Research Laboratory report (Lynch et al., 1976) entitled: Constraints on Development of Coal Mining in Arctic Alaska: Based on Review of Eurasian Arctic Practices:

CONSTRAINTS ASSOCIATED WITH PERMAFROST

The effect of permafrost on excavations is a function of temperature and ice content. Cold permafrost is considerably stronger than that with a temperature just below freezing. Ice-rich permafrost is more likely to cause difficulties than ice-free permafrost. Permafrost with temperature near thawing is very liable to contain water and thawed areas are inherently very weak. Some Russian sources have placed a rock temperature of -1.3°C as a critical lower boundary at which thawing problems develop in coal mines.

Roof Support

Air entering an opening, regardless of external ambient air temperature, attains the temperature of the surrounding rock after penetrating a distance of from 100 to 1,000 meters, depending on the ambient air temperature and volume of air. For this reason, the greatest difficulties in roof support are encountered near the opening. Various means of roof support near the entries have been adopted. These include roof bolts and nets immediately after the mine is opened; extensive wood or concrete support for permanent openings; and drill holes alongside permanent vertical shafts to remove excess heat.

temperatures encountered above ground. In addition, frozen water can create extremely unpleasant working conditions and even the hazard of frost bite.. Ice can also clog nozzles, conveyors, and other equipment.

Water is usually not available in large amounts in permafrost coal mines, and where it does occur, it is more likely to be a hazard rather than an asset. In some circumstances cracks or fissures may exist which can cause sudden inflows of water from the surface. Water is often available under the permafrost, so that mining below the permafrost level is similar to that in nonpermafrost areas. However, employment of water in large quantities for dust suppression in subpermafrost mines will lead to difficulties in coal transport and storage particularly above ground under winter conditions.

Mine safety regulations regarding water supply requirements for dust suppression in permafrost mining will have to recognize the serious difficulties involved in utilizing water.

APPENDIX IV

TABLE IV-2

CONSTRUCTION AND MAINTENANCE COSTS OF WINTER TRAILS AND ROADWAYS

<u>Type</u>	<u>Construction Costs</u> <u>(\$/Mi)</u>	<u>Maintenance Costs/</u> <u>Season</u> <u>(\$/Mi)</u>
Snowmachine Trail	1000 - 2000	100
Compacted Snow Road	1000 - 1500	2000 - 2500
Processed Snow Road	1500 - 2000	2000 - 2500
Ice-Capped Snow Road	4000 - 6500	2000 - 2500
Solid Ice Road	2000 - 20,000 ⁽¹⁾	
Ice Aggregate Road	20,000 - 30,000 ⁽¹⁾	

⁽¹⁾ Includes maintenance for season.

Source: Alaska Department of Transportation and Public Facilities, 1980.

TABLE IV-1

OPERATING COSTS OF REPRESENTATIVE OFF-ROAD HAUL VEHICLES

Type	Make & Model	Payload (lb)	Operating Speed (MPH)			Operating Costs (\$) per Ton-Mile		
			Flat(1) Terrain	Rolling(2) Terrain	Hilly(3) Terrain	Flat Terrain	Rolling Terrain	Hilly Terrain
Snow-machine	Various	500 (sled)	20(E) 25	10(E)	-	\$1.88	\$3.76	-
Utility	Tucker Sno-Cat 1700	2300	9-14	6-10	3-9	3.53	5.30	8.48
Heavy Duty	Foremost Nodwell 110	16,000	8-12	5-10	3-8(E)	0.77	1.29	1.94
Heavy Duty	Foremost Delta-3	30,000	20-30	10-20(E)	-	0.18	0.29	-
Heavy Duty	CATCO Rolligon RD-85	30,000	15	10(E)	-	0.58	0.87	-
Heavy Duty	Caterpillar D7G	80,000 (sled)	3-5	2-3	2(4)	0.49	0.99	1.98
Heavy Duty	Various	40,000	20-30	15-20	5-10	NA	0.05	-

Notes: (1) Flat Terrain, 0-3% grades; (2) Rolling terrain, grades 8-10%; (3) Hilly terrain, grades 15-20%; (4) with reduced payload; (E) Estimated.

Source: Alaska Department of Transportation and Public Facilities, 1980.

APPENDIX V

NOTES FOR TABLES V-1 THROUGH V-5

1. Mining costs are based on tons mined for each use with cost per ton based on total tonnage of mine operation.
2. Road costs are based on a percentage of costs. The percentage is the amount of the total coal moved over the road in the subscenario for each use (direct burning or electricity).
3. See Table 3-1 for cost per day of barge operation.
4. Vehicle mode and costs are based on scale of operations.
5. See Table 1-3 for power plant costs.
6. Costs are calculated at an average value of \$150,000 per mile, and an annual operating cost of \$10,000 per mile.
7. See Table 1-2 for KWH per year.

TABLE V-1

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost
<u>Mining Costs</u>							
Chicago Cr., Operating @	tons	tons	Note 1				
Kallarichuk Operating @	14253 tons	11141 tons	Note 1	1838	195	364	559
Ambler Mine Operating @	tons	tons	Note 1				
Kogoluktuk Operating @	tons	tons	Note 1				
Subtotal: Mining Costs				1838	195	364	559
<u>Transportation</u>							
<u>Roads: (miles)</u>							
Chicago Creek to Barge (16)		percent	Note 2				
Kallarichuk to Kiana (16)		78 percent	Note 2	2184	147	41	188
Kallarichuk to Barge (4)		percent	Note 2				
Ambler Mine to Ambler (10)		percent	Note 2				
Kogoluktuk Mine to Shungnak (12)		percent	Note 2				
Kogoluktuk Mine to Kobuk (6)							
<u>Barges:</u>							
		days/yr	Note 3				
River		days/yr	Note 3				
Coastal		days/yr	Note 3				
<u>Vehicles: (miles)</u>							
Chicago Cr. (16)		ton-miles for elect.	Note 4				
Kallarichuk Mine to:							
Kiana (16)	11141 x 16 = 178256	ton-miles for elect.	Note 4	214	25	21	46
Noorvik (4)		ton-miles for elect.	Note 4				
Selawik (4)		ton-miles for elect.	Note 4				
Ambler Mine to:							
Ambler (10)		ton-miles for elect.	Note 4				
Kogoluktuk to:							
Shungnak (12)		ton-miles for elect.	Note 4				
Kobuk (6)		ton-miles for elect.	Note 4				
Subtotal of Transportation Costs				2398	172	62	234
<u>Electric Generation</u>							
Generating Plant	5.0 MW		Note 5	7500	383	350	1293
Transmission Line	351 miles		Note 6	52650	2686	3510	6196
Subtotal of Electric Generation Costs:				60150	3069	3860	7489
TOTAL COSTS:				64386	3436	4286	8282
Number of Kilowatt Hours per year:	16.32 x 10 ⁶		Note 7				
Weighted Average Electricity Cost: \$0.56 per KWH (Increased by 10 percent for transmission line loss)							

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost
Mining Costs							
Chicago Cr., Operating @	18309 tons	18309 tons	Note 1	3378	323	595	918
Kallarichuk Operating @	14253 tons	3112 tons	Note 1	513	54	102	156
Ambler Mine Operating @	454 tons	454 tons	Note 1	73	8	16	24
Kogoluktuk Operating @	656 tons	656 tons	Note 1	106	11	23	34
Subtotal: Mining Costs				4070	396	736	1132
Transportation							
<u>Roads: (miles)</u>							
Chicago Creek to Barge (16)		100 percent	Note 2	2800	188	53	241
Kallarichuk to Kiana (16)		22 percent	Note 2	616	41	12	53
Kallarichuk to Barge (4)		100 percent	Note 2	700	47	13	60
Ambler Mine to Ambler (10)		100 percent	Note 2	1750	118	33	151
Kogoluktuk Mine to Shungnak (12)		100 percent	Note 2	2100	141	40	181
Kogoluktuk Mine to Kobuk (6)		100 percent		1050	71	20	91
<u>Barges:</u>							
		days/yr	Note 3				
River		days/yr	Note 3	1030	53	973	1026
Coastal		days/yr	Note 3				
<u>Vehicles: (miles)</u>							
Chicago Cr. (16)	18309 x 16 = 292944	ton-miles for heat	Note 4	230	41	35	76
Kallarichuk Mine to:							
Kiana (16)	692 x 16 = 11072	ton-miles for heat	Note 4	25	3	13	16
Noorvik (4)	1187 x 4 = 4748	ton-miles for heat	Note 4	25	3	6	9
Selawik (4)	1233 x 4 = 4932	ton-miles for heat	Note 4	25	3	6	9
Ambler Mine to:							
Ambler (10)	454 x 10 = 4540	ton-miles for heat	Note 4	25	3	5	8
Kogoluktuk to:							
Shungnak (12)	495 x 12 = 5940	ton-miles for heat	Note 4	25	3	1	4
Kobuk (6)	161 x 6 = 966	ton-miles for heat	Note 4	25	3	1	4
Subtotal of Transportation Costs				10426	718	1211	1929
TOTAL COSTS				14496	1114	1947	3061
TOTAL TONNAGE USED FOR DIRECT SPACE HEAT		16111					
Weighted Average Cost per ton delivered to communities served:				\$190.0			

TABLE V-2
SUBSCENARIO 1.2 - REGIONAL PLANT AT KOTZEBUE
COSTS ASSOCIATED WITH GENERATION OF ELECTRICITY INCLUDING 10 PERCENT ELECTRIC SPACE HEAT
(\$000)

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost
<u>Mining Costs</u>							
Chicago Cr., Operating @	35466 tons	17157 tons	Note 1	2368	252	558	810
Kallarichuk Operating @	tons	tons	Note 1				
Ambler Mine Operating @	tons	tons	Note 1				
Kogoluktuk Operating @	tons	tons	Note 1				
Subtotal: Mining Costs				2368	252	558	810
<u>Transportation</u>							
<u>Roads: (miles)</u>							
Chicago Creek to Barge (16)		48 percent	Note 2	1344	90	25	115
Kallarichuk to Kiana (16)		percent	Note 2				
Kallarichuk to Barge (4)		percent	Note 2				
Ambler Mine to Ambler (10)		percent	Note 2				
Kogoluktuk Mine to Shungnak (12)		percent	Note 2				
Kogoluktuk Mine to Kobuk (6)							
<u>Barges:</u>							
		days/yr	Note 3				
River		days/yr	Note 3				
Coastal		days/yr	Note 3	861	44	813	857
Barge Loading/Unloading	.48(6000)			2880	147	86	233
<u>Vehicles: (miles)</u>							
Chicago Cr. (16) x 17157 = 274512		ton-miles for elect.	Note 4	171	38	33	71
Kallarichuk Mine to:							
Kiana (16)		ton-miles for elect.	Note 4				
Noorvik (4)		ton-miles for elect.	Note 4				
Selawik (4)		ton-miles for elect.	Note 4				
Ambler Mine to:							
Ambler (10)		ton-miles for elect.	Note 4				
Kogoluktuk to:							
Shungnak (12)		ton-miles for elect.	Note 4				
Kobuk (6)		ton-miles for elect.	Note 4				
Subtotal of Transportation Costs				5256	319	957	1276
<u>Electric Generation</u>							
Generating Plant	5.0 MW		Note 5	7500	383	350	1293
Transmission Line	368 miles		Note 6	55200	2816	3680	6496
Subtotal of Electric Generation Costs:				6270	3199	4030	7789
TOTAL COSTS:				70324	3770	5545	9875
Number of Kilowatt Hours per year:	16.32 x 10 ⁶		Note 7				
Weighted Average Electricity Cost:	\$0.66 per KWH						

TABLE V-2
SUBSCENARIO 1.2 - REGIONAL POWER PLANT AT KOTZEBUE
COSTS ASSOCIATED WITH PROVIDING COAL FOR 90 PERCENT OF DIRECT HEATING DEMAND
(\$000)

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost
<u>Mining Costs</u>							
Chicago Cr., Operating @	35466 tons	18309 tons	Note 1	2527	269	595	864
Kallarichuk Operating @	3112 tons	3112 tons	Note 1	604	64	121	185
Ambler Mine Operating @	454 tons	454 tons	Note 1	73	8	16	24
Kogoluktuk Operating @	656 tons	656 tons	Note 1	106	11	23	34
Subtotal: Mining Costs				3310	352	755	1107
<u>Transportation</u>							
<u>Roads: (miles)</u>							
Chicago Creek to Barge (16)		52 percent	Note 2	1456	98	28	126
Kallarichuk to Kiana (16)		100 percent	Note 2	2800	188	53	241
Kallarichuk to Barge (4)		100 percent	Note 2	700	47	13	60
Ambler Mine to Ambler (10)		100 percent	Note 2	1750	118	33	151
Kogoluktuk Mine to Shungnak (12)		100 percent	Note 2	2100	141	40	181
Kogoluktuk Mine to Kobuk (6)		100		1050	71	20	91
<u>Barges:</u>							
		days/yr	Note 3				
River		days/yr	Note 3	1030	53	973	1026
Coastal		days/yr	Note 3				
Barge Loading/Unloading	52 (6000)			3120	159	94	253
<u>Vehicles: (miles)</u>							
Chicago Cr. (16) x 18309 =	292,944	ton-miles for heat	Note 4	179	41	35	76
Kallarichuk Mine to:							
Kiana (16) x 692 =	11,072	ton-miles for heat	Note 4	26	3	13	16
Noorvik (4) x 1187 =	4,748	ton-miles for heat	Note 4	26	3	6	9
Selawik (4) x 1233 =	4,932	ton-miles for heat	Note 4	26	3	6	9
Ambler Mine to:							
Ambler (10) x 450 =	4,500	ton-miles for heat	Note 4	26	3	5	8
Shungnak (12) x 495 =	5,940	ton-miles for heat	Note 4	26	3	7	10
Kobuk (6) x 161 =	966	ton-miles for heat	Note 4	26	3	1	4
Subtotal of Electric Generation Costs:				14341	934	1327	2261
TOTAL COSTS:				17651	1286	2082	3368
TOTAL TONNAGE USED FOR DIRECT SPACE HEAT 16111							
Weighted Average Cost per ton delivered to communities served:				\$209			

TABLE V-3

Mining Costs

Subtotal: Mining Costs

Transportation

Roads: (miles)

Chicago Creek to Barge (16)	43 percent	Note 2	1213	81	23	104
Kallarichuk to Kiana (16)	percent	Note 2				
Kallarichuk to Barge (4)	percent	Note 2				
Ambler Mine to Ambler (10)	percent	Note 2				
Kogoluktuk Mine to Shungnak (12)	percent	Note 2				
Kogoluktuk Mine to Kobuk (6)						

Barges :

River	days/yr	Note 3				
Coastal	days/yr	Note 3	703	36	664	700
Barge Loading/Unloading (@ \$6000).43			2598	132	77	209

Vehicles: (miles)

Chicago Cr. (16)	x 14000 = 224,000	ton-miles for elect.	Note 4	154	31	27	58
Kallarichuk Mine to:							
Kiana (16)		ton-miles for elect.	Note 4				
Noorvik (4)		ton-miles for elect.	Note 4				
Selawik (4)		ton-miles for elect.	Note 4				
Ambler Mine to:							
Ambler (10)		ton-miles for elect.	Note 4				
Kogoluktuk to:							
Shungnak (12)		ton-miles for elect.	Note 4				
Kobuk (6)		ton-miles for elect.	Note 4				

Subtotal of Transportation Costs	4668	280	791	1071
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Electric Generation

Generating Plant	3.0 MW	Note 5	6000	306	300	848
Transmission Line	0 miles	Note 6				

Subtotal of Electric Generation Costs:	<u>12600</u>	<u>792</u>	<u>1546</u>	<u>2580</u>
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TOTAL COSTS:

Number of Kilowatt Hours per year: 13.32×10^6 Note 7

Weighted Average Electricity Cost: \$0.20 per KWH
(Increased by 10 percent for transmission line losses)

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost	
<u>Mining Costs</u>								
Chicago Cr., Operating @	32309	tons	18309 tons	Note 1	2527	269	595	864
Kallarichuk Operating @		tons	tons	Note 1				
Ambler Mine Operating @		tons	tons	Note 1				
Kogoluktuk Operating @		tons	tons	Note 1				
Subtotal: Mining Costs					2527	269	595	864
<u>Transportation</u>								
<u>Roads: (miles)</u>								
Chicago Creek to Barge (16)		57 percent	Note 2	1587	107	30	137	
Kallarichuk to Kiana (16)		percent	Note 2					
Kallarichuk to Barge (4)		percent	Note 2					
Ambler Mine to Ambler (10)		percent	Note 2					
Kogoluktuk Mine to Shungnak (12)		percent	Note 2					
Kogoluktuk Mine to Kobuk (6)								
<u>Barges:</u>								
		days/yr	Note 3					
River		days/yr	Note 3					
Coastal		days/yr	Note 3	919	47	868	915	
Barge Loading/Unloading .57 (21 + 21)				3420	174	103	277	
<u>Vehicles: (miles)</u>								
Chicago Cr. (16) x 18309 = 292,944		ton-miles for heat	Note 4	205	41	35	76	
Kallarichuk Mine to:								
Kiana (16)		ton-miles for heat	Note 4					
Noorvik (4)		ton-miles for heat	Note 4					
Selawik (4)		ton-miles for heat	Note 4					
Ambler Mine to:								
Ambler (10)		ton-miles for heat	Note 4					
Shungnak (12)		ton-miles for heat	Note 4					
Kobuk (6)		ton-miles for heat	Note 4					
Subtotal of Electric Generation Costs:				6131	369	1036	1405	
TOTAL COSTS:				8658	638	1631	2269	
TOTAL TONNAGE USED FOR DIRECT SPACE HEAT 11,889 tons								
Weighted Average Cost per ton delivered to communities served: \$191.0								

TABLE V-4

Mining Costs

Subtotal: Mining Costs

Transportation

Roads: (miles)

Chicago Creek to Barge (16)		percent	Note 2				
Kallarichuk to Kiana (16)	67	percent	Note 2	1884	127	35	161
Kallarichuk to Barge (4)		percent	Note 2				
Ambler Mine to Ambler (10)		percent	Note 2				
Kogoluktuk Mine to Shungnak (12)		percent	Note 2				
Kogoluktuk Mine to Kobuk (6)							

<u>Barges:</u>	days/yr	Note 3
River	days/yr	Note 3
Coastal	days/yr	Note 3

Vehicles: (miles)

Chicago Cr. (16)	ton-miles for elect.	Note 4				
Kallarichuk Mine to:						
Kiana (16) x 1424 = 22,784	ton-miles for elect.	Note 4	51	6	26	32
Noorvik (4)	ton-miles for elect.	Note 4				
Selawik (4)	ton-miles for elect.	Note 4				
Ambler Mine to:						
Ambler (10)	ton-miles for elect.	Note 4				
Kogoluktuk to:						
Shungnak (12)	ton-miles for elect.	Note 4				
Kobuk (6)	ton-miles for elect.	Note 4				

Subtotal of Transportation Costs	1935	133	61	193
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Electric Generation

Generating Plant	0.5 MW	Note 5	3000	153	150	379
Transmission Line	73 miles	Note 6	10450	510	730	1240

Subtotal of Electric Generation Costs:	<u>13450</u>	<u>663</u>	<u>880</u>	<u>1619</u>
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TOTAL COSTS:	<u>15667</u>	<u>826</u>	<u>997</u>	<u>1898</u>
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Number of Kilowatt Hours per year: 2.08×10^6 Note 7
 Weighted Average Electricity Cost: \$0.96 per KWH
 (Increased by 5 percent for transmission line loss)

TABLE V-4
SUBSCENARIO 2.2 - SUB-REGIONAL POWER PLANT AT KIANA, SERVING KIANA, NOORVIK, SELAWIK
COSTS ASSOCIATED WITH PROVIDING COAL FOR 90 PERCENT OF DIRECT HEATING DEMAND
(\$000)

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost
<u>Mining Costs</u>							
Chicago Cr., Operating @	tons	tons	Note 1				
Kallarichuk Operating @	4536 tons	3112 tons	Note 1	591	66	122	188
Ambler Mine Operating @	tons	tons	Note 1				
Kogoluktuk Operating @	tons	tons	Note 1				
Subtotal: Mining Costs				591	66	122	188
<u>Transportation</u>							
<u>Roads: (miles)</u>							
Chicago Creek to Barge (16)		percent	Note 2				
Kallarichuk to Kiana (16)	33	percent	Note 2	924	62	17	79
Kallarichuk to Barge (4)	100	percent	Note 2	700	47	13	60
Ambler Mine to Ambler (10)		percent	Note 2				
Kogoluktuk Mine to Shungnak (12)		percent	Note 2				
Kogoluktuk Mine to Kobuk (6)							
<u>Barges:</u>							
		days/yr	Note 3				
River		days/yr	Note 3	111	6	105	111
Coastal		days/yr	Note 3				
<u>Vehicles: (miles)</u>							
Chicago Cr. (16)		ton-miles for heat	Note 4				
Kallarichuk Mine to:							
Kiana (16) x 692 = 11,072		ton-miles for heat	Note 4	26	3	13	16
Noorvik (4) x 1187 = 4,748		ton-miles for heat	Note 4	26	3	6	9
Selawik (4) x 1233 = 4,932		ton-miles for heat	Note 4	26	3	6	9
Ambler Mine to:							
Ambler (10)		ton-miles for heat	Note 4				
Shungnak (12)		ton-miles for heat	Note 4				
Kobuk (6)		ton-miles for heat	Note 4				
Subtotal of Electric Generation Costs:				1813	124	160	284
TOTAL COSTS:				2404	190	282	472
TOTAL TONNAGE USED FOR DIRECT SPACE HEAT 31129							
Weighted Average Cost per ton delivered to communities served:				\$152			

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost
Mining Costs							
Chicago Cr., Operating @	tons	tons	Note 1				
Kallarichuk Operating @	tons	tons	Note 1				
Ambler Mine Operating @	1080 tons	626 tons	Note 1	110	11.7	22.7	34
Kogoluktuk Operating @	tons	tons'	Note 1				
Subtotal: Mining Costs				110	11.7	22.7	34
Transportation							
<u>Roads: (miles)</u>							
Chicago Creek to Barge (16)		percent	Note 2				
Kallarichuk to Kiana (16)		percent	Note 2				
Kallarichuk to Barge (4)		percent	Note 2				
Ambler Mine to Ambler (10)	58	percent	Note 2	1015	68	19	87
Kogoluktuk Mine to Shungnak (12)		percent	Note 2				
Kogoluktuk Mine to Kobuk (6)							
<u>Barges:</u>							
		days/yr	Note 3				
River		days/yr	Note 3				
Coastal		days/yr	Note 3				
<u>Vehicles: (miles)</u>							
Chicago Cr. (16)		ton-miles for elect.	Note 4				
Kallarichuk Mine to:							
Kiana (16)		ton-miles for elect.	Note 4				
Noorvik (4)		ton-miles for elect.	Note 4				
Selawik (4)		ton-miles for elect.	Note 4				
Ambler Mine to:							
Ambler (10) x 626 = 6260		ton-miles for elect.	Note 4		3.8	7.2	11
Kogoluktuk to:							
Shungnak (12)		ton-miles for elect.	Note 4				
Kobuk (6)		ton-miles for elect.	Note 4				
Subtotal of Transportation Costs				1015	71.8	26.2	98
Electric Generation							
Generating Plant	0.2 MW		Note 5	3000	153	150	379
Transmission Line	51 miles		Note 6	7650	390	765	1155
Subtotal of Electric Generation Costs:				10650	543	915	1534
TOTAL COSTS:				117757	626.5	963.9	1666

Note 7

Weighted Average Electricity Cost: \$1.90 per KWH
(Increased by 5 percent for transmission line loss)

TABLE V-5

	Quantity	Unit	Cost Per Unit	Initial Capital Investment	Annual Capital Charge	Annual Operating Cost	Total Annual Cost
Mining Costs							
Chicago Cr., Operating @	tons	tons	Note 1				
Kallarichuk Operating @	tons	tons	Note 1				
Ambler Mine Operating @	1080 tons	454 tons	Note 1	79.5	8.5	16.5	25
Kogoluktuk Operating @	656 tons	656 tons	Note 1	106	11	23	35
Subtotal: Mining Costs				185.5	19.5	39.5	59
Transportation							
<u>Roads: (miles)</u>							
Chicago Creek to Barge (16)		percent	Note 2				
Kallarichuk to Kiana (16)		percent	Note 2				
Kallarichuk to Barge (4)		percent	Note 2				
Ambler Mine to Ambler (10)	42	percent	Note 2	735	50	14	64
Kogoluktuk Mine to Shungnak (12)	100	percent	Note 2	2100	141	40	181
Kogoluktuk Mine to Kobuk (6)	100			1050	71	20	91
<u>Barges:</u>							
		days/yr	Note 3				
River		days/yr	Note 3				
Coastal		days/yr	Note 3				
<u>Vehicles: (miles)</u>							
Chicago Cr. (16)		ton-miles for heat	Note 4				
Kallarichuk Mine to:							
Kiana (16)		ton-miles for heat	Note 4				
Noorvik (4)		ton-miles for heat	Note 4				
Selawik (4)		ton-miles for heat	Note 4				
Ambler Mine to:							
Ambler (10) x 454 = 4540		ton-miles for heat	Note 4		2.7	5.2	8
Shungnak (12) x 495 = 5940		ton-miles for heat	Note 4		3.6	6.8	10
Kobuk (6) x 161 = 966		ton-miles for heat	Note 4		2.9	1.1	4
Subtotal of Electric Generation Costs:				3885	271.2	87.1	358
TOTAL COSTS:				4071	290.1	126.6	417
TOTAL TONNAGE USED FOR DIRECT SPACE HEAT 1110 tons							
Weighted Average Cost per ton delivered to communities served: \$375.6							

