TABLE 2.8. Estimated Natural Gas Acquisition Cost for Chugach Electric Association Without Pacific Alaska LNG Plant, 1982 $'s, 0% Inflation

Year	Beluga Bcf/Yr	Beluga $/Mcf	Alaska Gas and Service Bcf/Yr	Alaska Gas and Service $/Mcf	Supplemental Gas Bcf/Yr	Supplemental Gas $/Mcf[a]	Weighted Average Gas Bcf	Weighted Average Gas $/Mcf
1980	17.76	0.27	3.95 (3.98)[b]	1.34 (1.04)	--	--	21.71	0.46
1981	18.66	0.26	4.15 (4.65)	1.32 (1.20)	--	--	22.81	0.45
1982	19.60	0.27	4.35	1.33	--	--	23.95	0.46
1983	20.57	0.27	4.57	1.31	--	--	25.14	0.46
1984	21.63	0.27	4.80	1.32	--	--	26.43	0.46
1985	21.90	0.27	5.04	1.33	--	--	26.94	0.51
1986	21.90	0.28	5.17	1.62	0.41	1.62[a]	27.48	0.54
1987	21.90	0.28	5.31	1.84	1.01	1.84[a]	28.22	0.66
1988	21.90	0.30	5.45	1.95	1.62	1.95[a]	28.97	0.70
1989	21.90	0.30	5.60	2.16	2.25	2.16[a]	29.75	0.78
1990	21.90	0.32	5.75	2.41	2.89	2.41[a]	30.54	0.90
1991	21.90	0.32	6.04	4.01	4.84	4.01	32.78	1.53
1992	21.90	0.34	6.35	4.10	5.20	4.10	33.45	1.66
1993	21.90	0.34	6.67	4.18	7.63	4.18	36.20	1.87
1994	21.90	0.36	7.01	4.27	9.13	4.27	38.04	2.00
1995	21.90	0.36	7.36	4.37	10.71	4.37	39.97	2.17
1996	0	--	7.48	4.46	34.09	4.46	41.57	4.46
1997	0	--	7.58	4.56	35.65	4.56	43.23	4.56
1998	0	--	7.69	4.68	37.27	4.68	44.96	4.68
1999	0	--	7.79	4.79	38.97	4.78	46.76	4.78
2000	0	--	7.88	4.91	40.75	4.91	48.63	4.91

(a) The minimum price available from AGAS or Beluga Field producers, assumed to be about equal.
(b) Items in parentheses are actual percent and quantities for 1980 and 1981.

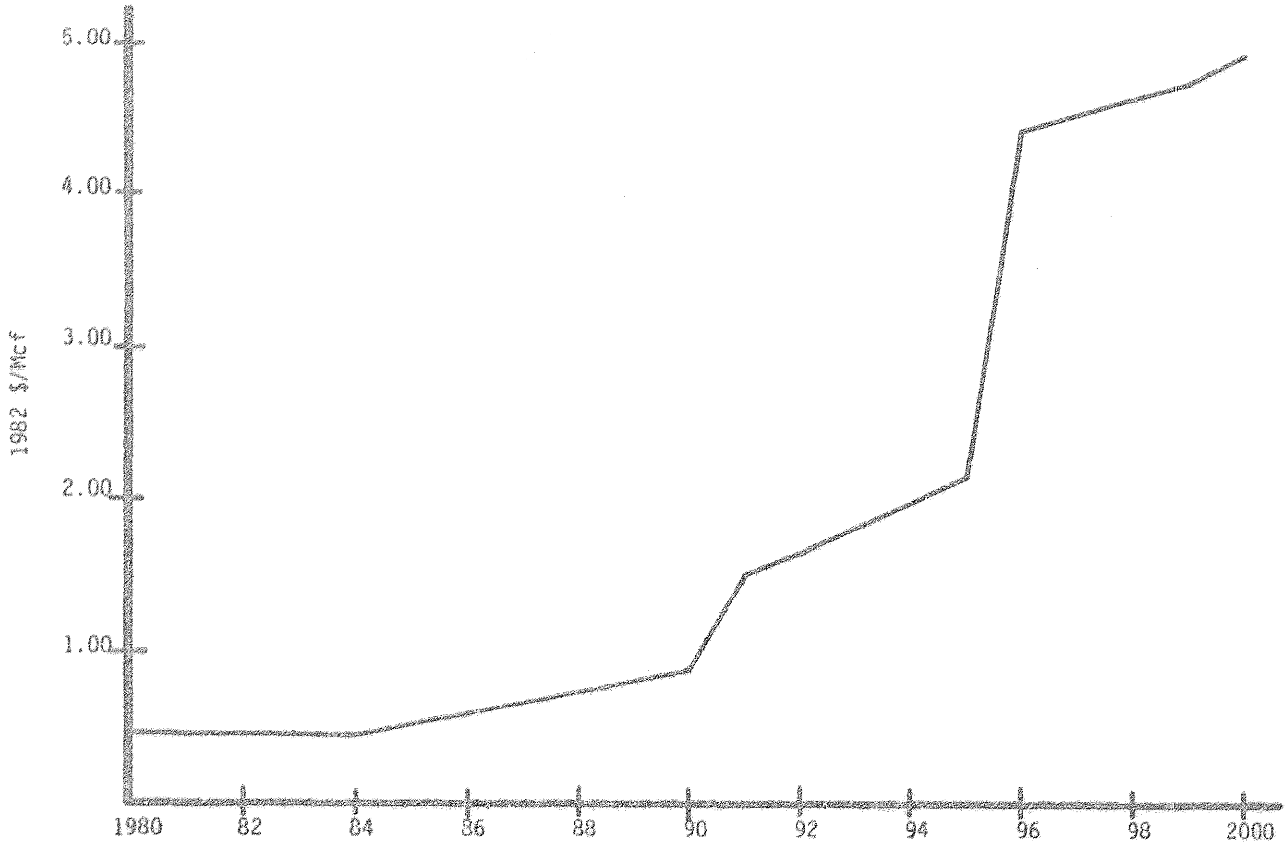


FIGURE 2.3. Weighted Average Natural Gas Acquisition Cost--Chugach Electric Association Without Pacific Alaska LNG Plant

Pacific Alaska LNG Associates or Similar Project Proceeds

The principal price change introduced by this scenario is to sharply increase the cost of natural gas provided from the Beluga River Field to CEA and from the Kenai Field to AGAS. Using the same assumptions as employed in the previous scenario, the weighted average natural gas acquisition costs are developed for AGAS (Table 2.9) and CEA (Table 2.10). In this scenario, Chugach probably does not have the option of negotiating a contract for supplemental gas from the Beluga River Field producers and must take supplemental gas from sources such as AGAS or at least at comparable costs.

TABLE 2.9. Estimated Gas Price - Purchases by Alaska Gas and Service Company with Pacific LNG Gas, 1982 $'s, 0% Inflation

Year	North Cook Royalty Bcf/Yr	North Cook Royalty $/Mcf	All Other Gas Bcf/Yr	All Other Gas $/Mcf	Total Bcf/yr	Weighted Average Price, $/Mcf[a]
1980	4.00 (2.68)[b]	2.50 (1.18)	27.35 (29.44)	0.64 (0.58)	31.35 (32.12)	1.13 (0.63)
1981	4.00 (1.03)	2.56 (2.10)	28.57 (30.85)	0.64 (0.63)	32.57 (31.88)	1.11 (0.68)
1982	4.00	2.63	29.63	0.64	33.63	1.12
1983	4.00	2.68	30.84	0.64	34.84	1.10
1984	4.00	2.75	32.11	0.64	36.11	1.11
1985	4.00	2.82	34.44	0.64	37.44	1 [illegible]
1986	4.00	2.89	35.00	3.65	39.00	3.81
1987	4.00	2.96	35.59	3.73	39.59	3.89
1988	4.00	3.03	33.43	3.82	37.43	3.97
1989	4.00	3.12	34.60	3.92	38.60	4.08
1990	4.00	3.18	35.84	4.01	39.84	4.17
1991	0	--	41.45	4.09	41.45	4.33
1992	0	--	43.14	4.18	43.14	4.42
1993	0	--	44.90	4.24	44.90	4.48
1994	0	--	46.74	4.33	46.74	4.57
1995	0	--	48.66	4.66	48.66	4.70

(a) Includes delivery charge to Anchorage for assuring delivery during cold weather.
(b) Items in parentheses are actual quantities and prices for 1980 and 1981.

TABLE 2.10. Estimated Natural Gas Acquisition Cost - Chugach Electric Association with Pacific Alaska LNG, 1982 $'s, 0% Inflation

Year	Beluga Bcf/Yr	Beluga $/Mcf	Alaska Gas and Service Bcf/Yr	Alaska Gas and Service $/Mcf	Weighted Average Price, $/Mcf
1980	17.76	0.27	3.95 (3.98)[a]	1.33 (1.04)	0.46
1981	18.66	0.26	4.15 (4.65)	1.32 (1.20)	0.45
1982	19.60	0.27	4.35	1.33	0.46
1983	20.57	0.27	4.57	1.31	0.46
1984	21.63	0.27	4.80	1.32	0.46
1985	21.90	0.93	5.04	1.33	1.01
1986	21.90	0.95	5.58	4.02	1.59
1987	21.90	1.00	6.32	4.10	1.70
1988	21.90	2.07	7.07	4.18	2.58
1989	21.90	2.11	7.17	4.29	2.65
1990	21.90	2.15	7.45	4.38	2.71
1991	21.90	2.20	10.88	4.54	2.98
1992	21.90	2.24	11.55	4.63	3.07
1993	21.90	2.29	14.30	4.69	3.24
1994	21.90	2.33	16.14	4.78	3.37
1995	21.90	2.38	18.07	4.91	3.52

(a) Items in parentheses are actual prices and quantities for 1980 and 1981.

3.0 ALASKA COAL

In the context of electric power supplied from a central station utility, coal-fired thermal generation presents a clear alternative to hydroelectric or the natural gas/oil-fired generation systems in the Railbelt region. There are several reasons for considering coal:

- Resources within the region are large and can or could be made available at significantly lower costs (heating value basis) than oil or natural gas, particularly over the long term.
- The nature of steam coal markets and resources is such that price escalation over and above general inflation is not expected to be any higher than for oil and lower than for natural gas.
- Long-term supply contracts can be entered into, thus establishing relatively predictable future costs.
- National policy certainly encourages coal use in place of gas and oil, if not outrightly mandating its substitution for these fuels in large-scale operations.

Two major surface mineable coal reserves are located within the Railbelt region: the currently producing Nenana Coal Field near Healy (and connected to the Alaska Railroad), and the Beluga/Chuitna coal fields (not now producing) remotely located on the west side of Cook Inlet. Other coal reserves occur on the Kenai Peninsula and in the Matanuska Valley. The former are in the form of thin, lenticular deposits not suitable for large-scale mining, and the latter require more costly underground mining techniques. Still other reserves occur in the lower Susitna Basin and in the Jarvis Creek area. Little data exist for the reserves in these latter areas, and costs are speculative.

The Nenana coal field is now being produced by Usibelli Coal Mine, Inc. at a rate of about 700,000 tons per year (TPY). Coal is supplied by truck to the near-mine-mouth 25-MW Healy generation plant of the Golden Valley Electric Association. The Healy plant operates in a base load mode. Additional coal is crushed and marketed via the Alaska Railroad to the Fairbanks Municipal

Utilities System, the University of Alaska, and the military installations at Clear AFB, Eielson AFB and Fort Wainwright. More recently, the export market has been tested for the cement/lime industry in Korea via the Alaska Railroad and the Port of Anchorage.

The Beluga/Chuitna coal fields are in the exploratory and predevelopment phase. While containing large reserves, these fields are located in a region with little or no infrastructure and are not likely to be developed unless a firm market of 1.5-2 million TPY mine-mouth or 5 million TPY export, or some combination can be established. On an electric power equivalent basis, 1.5-2 million annual tonnage amounts to about 400 MW to 600 MW of baseloaded coal-fired power generation capacity, or just slightly less than equivalent to the capacity of the proposed Watana Dam in the Susitna hydroelectric project.

Should coal-fired power generation become a significant source of electricity production in the Railbelt, generation capacity would probably be added in increments ranging from 200 MW to 400 MW. This staging requirement might or might not, in itself, support opening the Beluga/Chuitna coal fields for local consumption. Nevertheless, the outlook for developing the Beluga/Chuitna fields for export to Pacific Rim markets appears favorable. In addition, Placer Amex Inc. and the Bass-Hunt-Wilson Group, the major leaseholders in the Beluga/Chuitna region, are pursuing coal-to-methanol conversion and a direct export mine, respectively.

While the current effort to develop the Beluga-Chuitna fields is mainly oriented toward large-scale mining (beginning at 5 to 6 million tons per year) for export, Battelle further explored the possibility of smaller mines with some of the producers in the Beluga area. One group stated that previous analysis done by themselves and others indicates that mines serving mine-mouth power plants might be opened for as little as 0.5 million tons per year. Furthermore, at 400 MW (about 1.4 million tons per year) a mine-mouth plant would probably be competitive with other sources of power and a 2 million tons year contract (600 MW) would be very attractive. These studies have not been reevaluated in light of more recent knowledge or for generating plants smaller than 400 MW. Another producer group states the situation a bit differently.

They agree that a coal mine with contracts for take-or-pay at 2 million tons per year to a mine-mouth plant would be attractive, as would a 2 to 3 million tons per year export mine with 2 to 3 million tons mine-mouth sales. There are circumstances where three-quarters of a million tons per year (enough to fire a single 200-MW plant) might be attractive enough to open the mine. It would depend on what additional demand (export and mine mouth) might be forthcoming, with what guarantees, and with what timing. A 200-MW plant by itself may or may not provide sufficient demand to open a mine in the Beluga-Chuitna fields. The producers aopear divided on this point.

In the base case analyzed in Volume I of the study, 200 MW of coal-fired generation is planned for 1992 at Beluga in Anchorage-Cook Inlet and 200 MW in Fairbanks-Tanana Valley at Nenana. Conceivably the Nenana plant could be built at Beluga, if necessary. Even so, the two increments of 200 MW called for in the base case might be spaced too far apart in time to open the mine in the absence of an export market. The prospects would be worse at lower demand in the absence of exports, since only one 200-MW plant might then be needed.

In the plan calling for increased use of coal, 600 MW of coal-fired generating capacity is planned for Beluga between 1997 and 2002, plus another 200 MW at Nenana. This would be enough demand to open a mine at Beluga if the producers could secure a take-or-pay contract for 400 to 600 MW worth of coal. The mine could be opened for the first 200 MW of demand if the producers had ironclad assurances that total deliveries would reach 400 to 600 MW within two to three years. Otherwise, exports could be required.

In any case where exports are required to open the mine, the exports must be sufficient to pay for shipping facilities. This level of exports is about 4 million to 6 million tons per year without mine-mouth demand for electric generation. Even with mine-mouth demand, exports would have to total 2 to 4 million tons per year to pay for export facilities.

3.1 AVAILABILITY AND QUALITY

The Nenana field, located on the north slope of the Alaska Range, is currently producing at a rate of about 700,000 TPY and is operated by the

Usibelli Coal Mine, Inc. Existing mining capacity is about 2 million TPY and the present bases could support expansion to 4 million TPY. At this higher rate, mine life is expected to be about 60 years without significant depletion.

The quality of the coal is as follows:

Heating Value (coverage)	8000 Btu/lb
Ash Content	7-8% average 11% max.
Moisture	25-30%
Hardgrove Grindability Index	~34 as mined
Ash Softening Temperature	2100°F
Ash Na_2O Content	0.08%
Sulfur Content	<0.25%
Nitrogen Content	0.60%

The surface mineable Chuitna Field (the reference field for the Beluga region) is located about 12 miles from tidewater on the west side of Cook Inlet. The mine area would also be about 12 miles (air) from CEA's existing Beluga Generation Station and from the point of connection to the existing transmission corridor to the Cook Inlet load center.

A recent report by the Bechtel Corporation indicates that reserves of 350 million tons can be mined with a cumulative stripping ratio of 4.4 over a 30-year period (Bechtel Corporation 1980). Thus, a mining rate of 11.7 million TPY could be supported without significant depletion of the reserves that have received the greatest attention.

In order for Chuitna coal to be available for in-state use at a reasonable price, an export market might have to be established (see Section 3.0). The outlook for this development appears excellent; however, it is based primarily on the rapidly growing East Asian markets. In addition, time is required for mine design, and environmental and licensing activities. Based on these considerations, Chuitna coal could be available as early as 1986, but with more certainty by 1988. A decision on proceeding with development is expected in the early 1980s.

The run-of-mine quality of coal expected from the Chuitna Field is as follows:

Heating Value	7500-8200 Btu/lb
Ash Content	7-8%
Moisture	20-28%
Hardgrove Grindability Index	20-25
Ash Softening Temperature	2350°F
Ash Na_2O Content	0.95%
Sulfur Content	0.16-0.18%
Nitrogen Content	N.A.

3.2 COAL PRICE AND ESCALATION

The general approach used to forecast steam coal prices in Alaska is similar to that used for other fuels such as natural gas and petroleum-based fuels. That is, future prices are based on recent actual or estimated prices and then modified for the future based on the concept of an "opportunity price." This price is that which the seller would receive in the open market. This approach, therefore, necessitates some understanding of the steam coal market and price formation factors at least for those coals which have access to alternative non-Alaskan markets. In this case, these markets are primarily in East Asia.

A recent study by Battelle-Northwest addressed the steam coal market outlook on the Pacific Rim (East Asian and U.S. West Coast) in relation to the potential development of the Beluga Coal Fields (Swift, Haskins, and Scott 1980). That report made several points relevant to this study:

1. Steam coal markets differ substantially from petroleum markets. Long-term contracts are common in order to accommodate the financing needs of the producers on one hand, and assure relatively firm supplies and prices of known-quality coal to the purchasers on the other. Quite frequently, purchasers seek an equity position in the producing operation to assure stability.

2. Market prices are determined primarily by the costs of production plus profit. This is in contrast to crude oil markets where prices are established by national oil companies or the host governments in producing countries. The coal markets are thus generally competitive. High world oil prices provide the major stimulus for switching to coal but, because of the competitive nature of the market, do not actually establish coal prices.

3. In turn, the costs of production are determined primarily by the nature of the mining operation, e.g., surface versus underground, and the geologic conditions such as thickness of seams, depth of overburden, and general terrain conditions.

4. For reasons of transportation costs, Alaska's coal market appears to be decoupled from the western U.S. market and will more likely be closely linked by international trade to East Asia, and specifically to Korea, Japan and Taiwan. In these markets, Alaskan coal will compete primarily with coals from Australia, South Africa, Canada, The People's Republic of China, and Western Canada. Due to high domestic rail transportation costs, western U.S. coals are not believed to be major long-term competitors.

5. Steam coal trade on the Pacific Rim is in its infancy with no well-established patterns as yet. Despite this, growth is expected to be dramatic as illustrated in Table 3.1. This has been brought about primarily by the high cost of the imported oil and liquefied natural gas, both of which can be displaced by coal, given adequate time for installation of new coal-fired plants.

6. Despite price disparities between different suppliers, coal purchasers and governments, e.g., Japanese electric power utilities and the Ministry of International Trade and Industry, appear to have taken the position that diversity in sources of supply is worth some cost penalty. In fact, it now appears that despite significant differences in coal costs, market shares for supplying countries will be determined more by policy decisions and less by pure economic considerations.

TABLE 3.1. Preliminary Projections of Steam Coal Imports by Country and Year (DOE 1981)[a]

	Million Tons Per Year			
	1979	1985	1990	2000
Japan	2.8	26.4	50.4	103.2-123.7
Korea	6.2	9.6	16.8	52.3
Taiwan	5.5	3.7	16.8	43.3
Hong Kong	N/A	4.8	9.6	12.0
Total	14.5	44.5	93.6	210.8-231.3

(a) Data adjusted to 11,500 Btu/lb coal by Battelle, Pacific Northwest Laboratories.

7. If the major East Asian coal-importing country, i.e., Japan, adheres to its announced policy of source diversification and includes the U.S. as a supplier, then Alaskan coal, particularly from the Cook Inlet region, could capture a major percentage of the U.S. exports to the Pacific Rim. This is because western U.S. coal fields have high overland transportation costs.

In addition to the question of whether Alaskan coal will enter international trade, the problem in forecasting future price lies in the fact that there is little market precedent in the Pacific Rim. Steam coal trade to date has been minuscule relative to its expected future levels; prospective purchasers in East Asia have had little experience with coal-fired plants; standards for contractual arrangements including equity participation in producing operations and infrastructure have not been worked out and tested.

Regardless of the above problems, it seems reasonable to expect that the Pacific Rim market will eventually function in a manner similar to the U.S. domestic market except that targets for diversified supplies will be set as a matter of policy rather than simply economics. With that exception, it appears that competitive market forces will prevail at least once an initial base contract price is established.

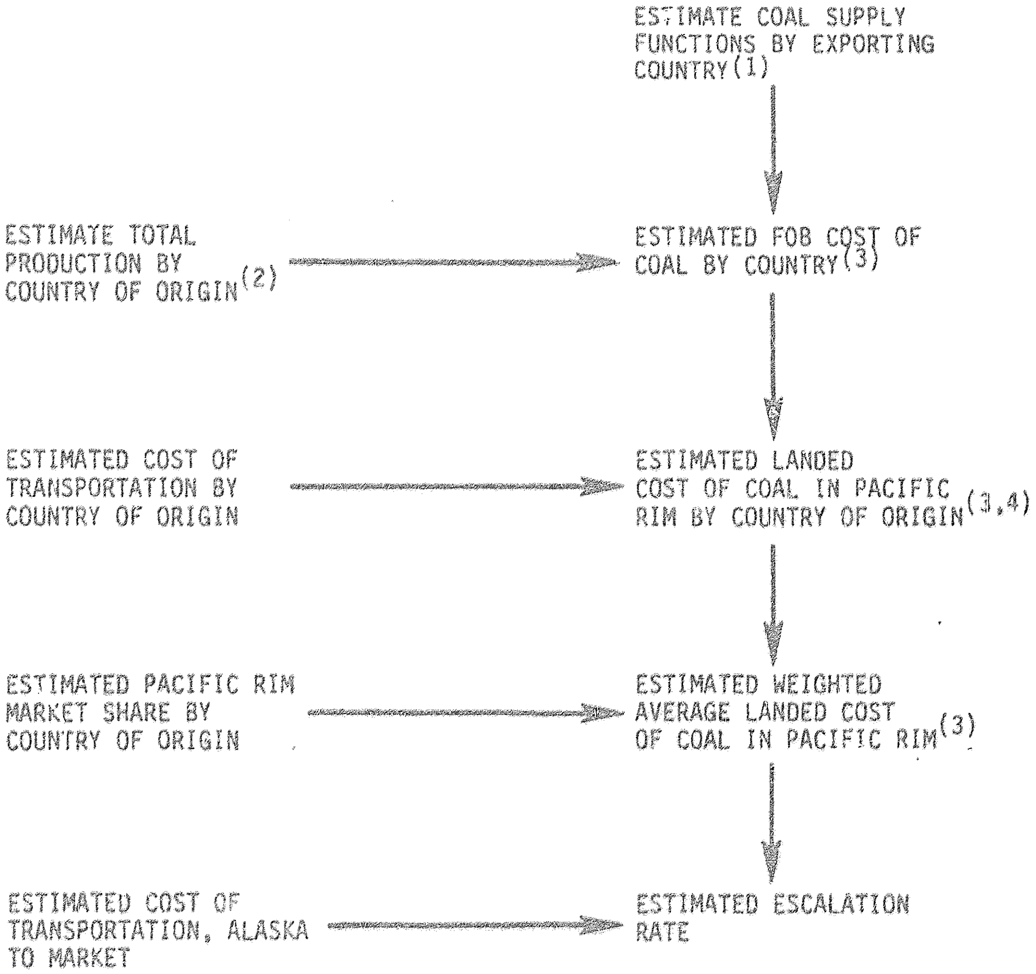
Because of the joint necessity for long-term contracts (10 years) on the part of both sellers and buyers, it seems likely that a contract for Alaskan coal will start with a negotiated base price established largely on the cost of production and delivery plus a reasonable rate of return. Clauses will be included to cover production cost increases or decreases due to changing mining conditions (e.g., geology), regulatory and tax changes, and labor and other cost factors.

In addition, it seems reasonable that the producers (including the equity participation by the purchaser) will require some marketplace clearing mechanisms. That is, they will require contract provisions that link the prices they receive for their coal to at least the changes in the landed cost of coals supplied from other sources.[a] Such terms are comparable to those currently applied to agreements for purchases of other energy commodities such as LNG and LPG.

3.2.1 Beluga/Chuitna Coal

Based on the above information and assumptions, the rationale for forecasting future prices of Alaskan steam coals (particularly those strongly tied to other markets) is shown diagrammatically in Figure 3.1. The process starts with estimates of coal supply functions (prices as a function of production rate) for steam coals for each of the sources of supply competing with Alaskan coal. These estimates are shown in Figures 3.2, 3.3, and 3.4 for supplies FOB dock Australia, South Africa and Canada, respectively. All prices are expressed in 1982 U.S. dollars and are based on composite supply functions for each country as shown disaggregated in Swift et al.'s Beluga Coal Market Study. A separate estimate for Wyoming coal (the steam coal from the contiguous United States believed most likely to be part of large tonnage contract exports) is not shown, as the nature of the reserves points to an essentially flat supply function. However, in general, essentially all supply

(a) Linkage to absolute cost levels (the free market approach) appears unlikely because of the policy decision to pre-establish target market shares.



(1) Price as function of production rate
(2) Production rate as function of time
(3) Price as function of time
(4) Japan used as proxy

FIGURE 3.1. Procedure for Estimating Steam Coal Price Escalation - Pacific Rim Markets

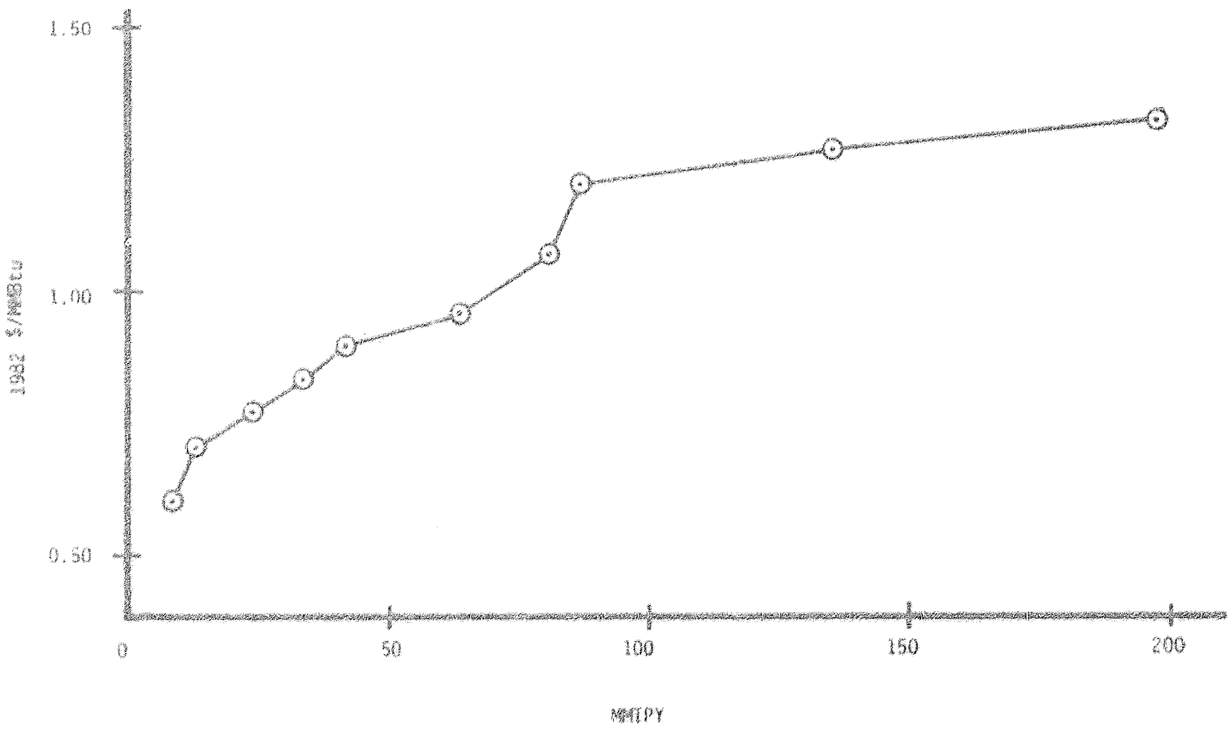


FIGURE 3.2. Composite Export Steam Coal Supply Function FOB Australia

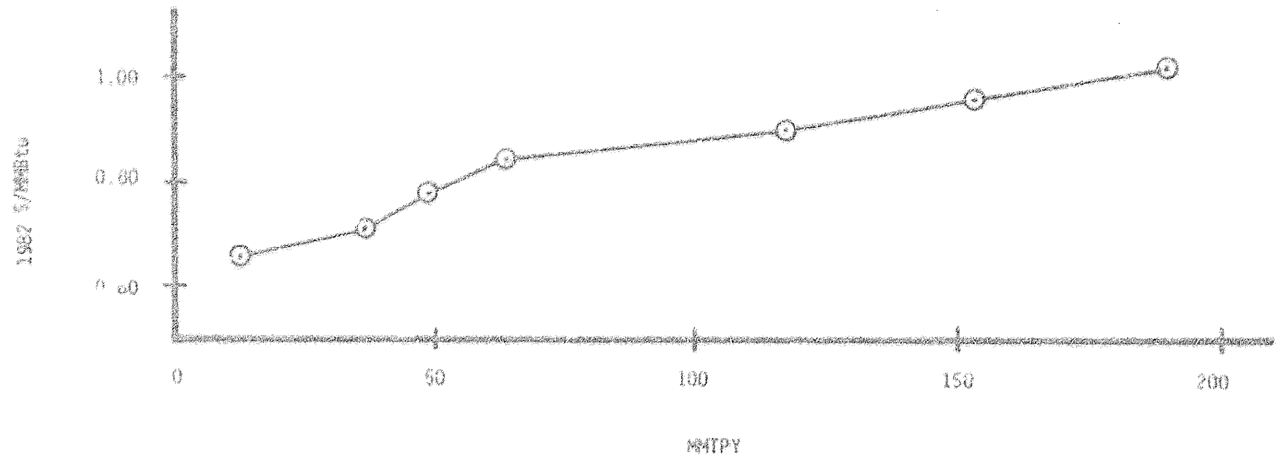


FIGURE 3.3. Composite Export Steam Coal Supply Function FOB South Africa

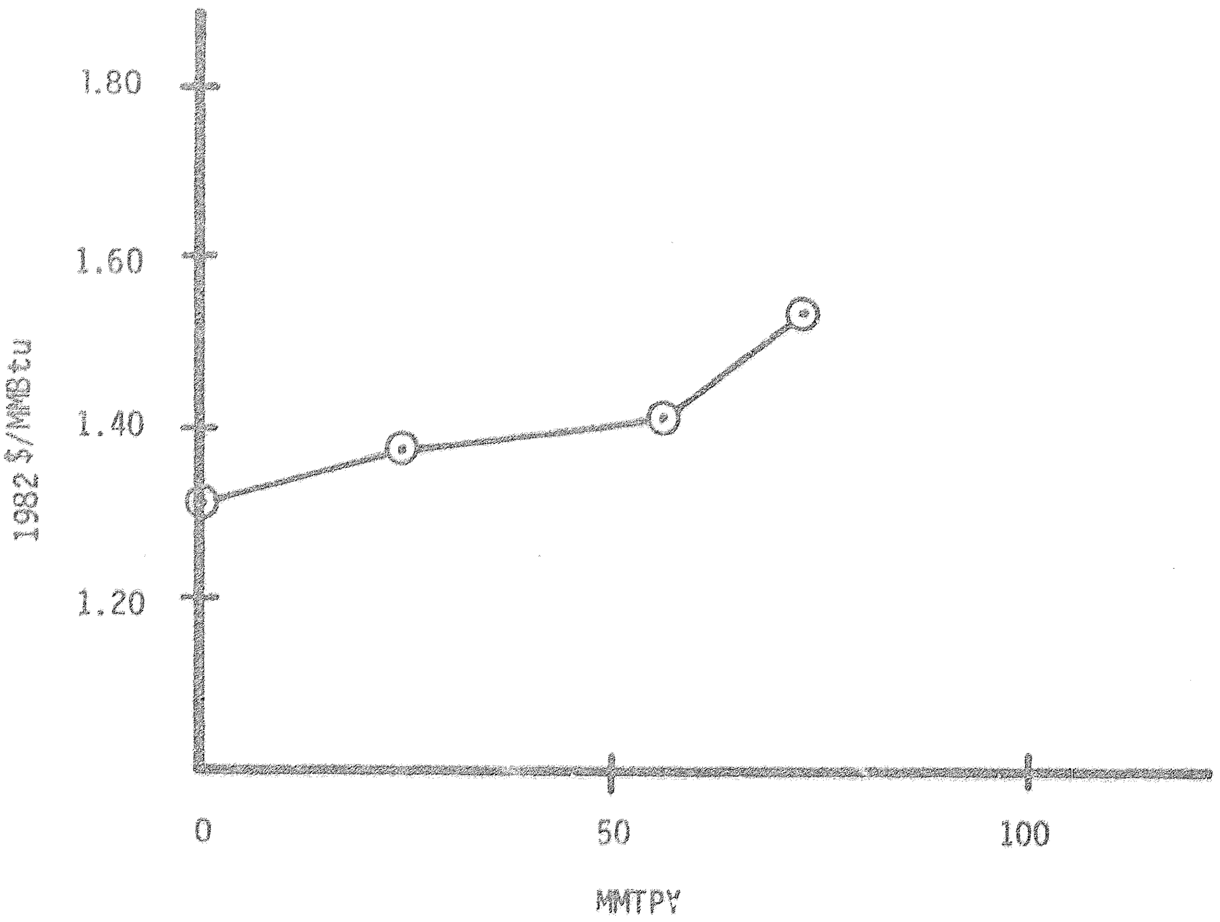


FIGURE 3.4. Composite Export Steam Coal Supply Function FOB Canada (British Columbia)

curves show upward trends as production rates increase. This comes about as each new increment of production capacity encounters more costly mining conditions, i.e., the marginal cost of production rises in real terms.

Next, estimates of total steam coal (of a grade likely to be exported) production rates over time are applied to the supply functions to estimate the future cost of coal FOB the producing country. The production rate estimates, shown in Table 3.2, are based on recent U.S. DOE forecasts that draw on a large number of estimates from domestic and foreign sources.

The findings of this stage of analysis are depicted in Figure 3.5. The range of future prices illustrates the uncertainty introduced by possible bands of production rates. Australian coal prices, though starting at the lowest level in 1985, increase more rapidly than others because of a combination of marked increases in expected production rates, coupled with moderate upward increases in costs of production.

TABLE 3.2. Estimated Total Export Steam Coal Production for Non-U.S. Countries Serving the Pacific Rim Markets (DOE 1981)

	Million Ton Per Year		
	1985	1990	2000
Australia	15-20	35-40	75-120
South Africa	40-50	60-70	80-180
Canada	4	4-10	4-24

Market shares (for producing countries) are then entered to yield the weighted average landed cost of steam coal delivered to Japan, which is a proxy for the Pacific Rim market as a whole. Estimated market shares are shown in Table 3.3 based on DOE studies.

Finally, the expected future costs of transportation to the Japan proxy market from Alaska are backed out from the weighted average landed cost from other major competitors to provide a "net-back" price to Cook Inlet. Not all potential suppliers are shown, primarily because of the absence of cost or price data for mainland China or Russia. Nevertheless, the results should be indicative and are given in Table 3.4.

These results show an initial price at mine-mouth of $1.29/MMBtu for shipments beginning 1985, with a real escalation rate of 2.1% over the period 1985 to 2000. This compares to recent discussions with the Bass-Hunt Wilson group, which indicate that the run-of-mine price of coal at mine-mouth is expected to be about $1.17/MMBtu in January 1981 dollars or $1.28/MMBtu in 1982 dollars. It must be recognized that these estimates are based on production costs and therefore represent a minimum estimate of price.

It is also useful to examine the actual prices of steam coal in the Pacific Rim. A sampling of 1980 spot prices for steam coal CIF Taiwan from Coal Week International yields a price of $1.66/MMBtu and early 1981 spot prices CIF Taiwan were $2.41. This is a rather sharp increase in price and may not be indicative of the long-term trend as steam coal suppliers are better able to meet the growing demand for steam coal. The average price of steam coal CIF to Japan was $2.18/MMBtu for 1980 assuming 12,000 Btu/lb and about $2.15/MMBtu in early 1981.

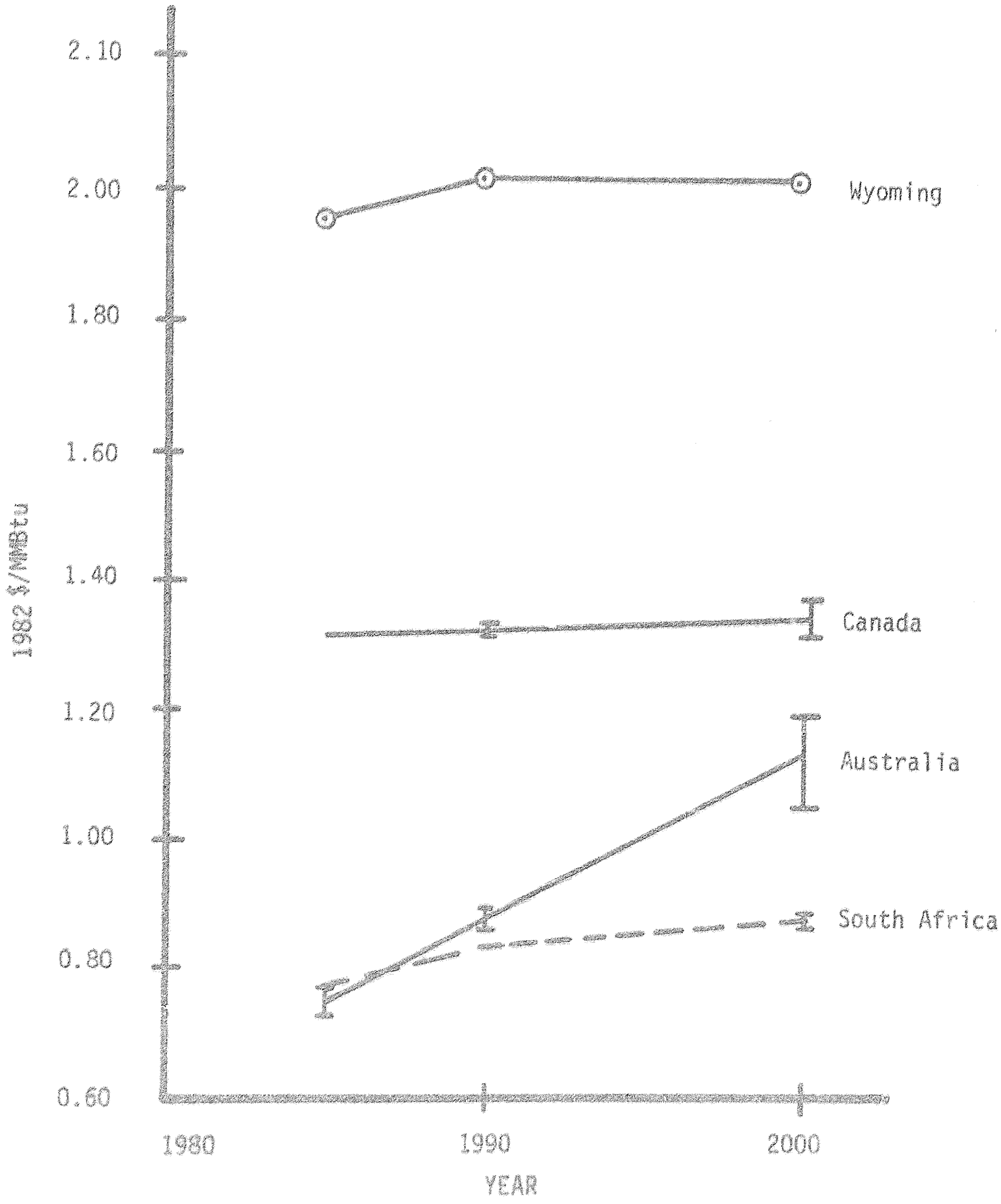


FIGURE 3.5. Estimated Coal Prices FOB Port of Origin

TABLE 3.3. Market Share of Steam Coal Trade in the Pacific Rim (DOE 1981)

	Percent					
	USA	Australia	South Africa	China	Canada	All Others
Japan						
1985	15	30	20	15	10	10
1990	15	30	20	15	10	10
2000	25	25	10	12	12	16
South Korea						
1985	--	50	50	--	--	--
1990	--	50	50	--	--	--
2000	--	50	50	--	--	--
Taiwan						
1985	20	60	--	--	20	--
1990	20	60	--	--	20	--
2000	20	60	--	--	20	--
Hong Kong						
1985	25	25	--	25	25	--
1990	25	25	--	25	25	--
2000	25	25	--	25	25	--

These recent prices can be adjusted to Alaska using an approximate shipping fee from Alaska to Taiwan of $0.60/MMBtu and to Japan of $0.50/MMBtu, and an approximate cost of $0.20/MMBtu from the Bechtel study to move the coal from the mine to the post. This provides a net-back price from Taiwan of about $1.60/MMBtu and $1.45/MMBtu from Japan. A simple average of these two would peg the Beluga mine-mouth price at about $1.53/MMBtu in early 1981 or about $1.66/MMBtu in January 1982 dollars.

The difference between the predicted production cost estimate ($1.29/MMBtu) and the estimated net-back price in the current market ($1.66/MMBtu) is about $0.37/MMBtu. This is a relatively small range given that there are no coal exports at present and that both numbers are estimates

TABLE 3.4. Steam Coal Prices Landed in Japan and Net-Back to Alaska (1982 $/MMBtu) (Swift, Haskins, and Scott) (DOE 1981)

Country of Origin	1985	1990	2000
Australia	1.30	1.46	1.83
Market Share %	30	30	25
Canada	1.88	1.92	2.03
Market Share %	10	10	12
South Africa	1.64	1.77	1.96
Market Share %	20	20	10
U.S. (other than Alaska)	2.99	3.16	3.30
Market Share [(a)]	15	15	25
Weighted Average Landed	1.81	1.95	2.41
Less Transportation Cost From Alaska	0.51	0.56	0.64
Net-Back	1.29	1.39	1.77
Escalation Rate %/Year	1.6%	2.4%	

(a) U.S. market share of Japan coal markets adjusted to reflect only non-Alaskan coal, Wyoming source assumed.

based upon different sets of information. This analysis will average the two prices to arrive at a mean price of $1.48/MMBtu with the two estimates representing the high and low prices.

The escalation rate of 2.1% for the period 1985 to 2000 is felt to be a reasonable estimate of the future behavior of steam coal prices. During the 1970s, steam coal prices to utilities in the "lower 48" escalated at slightly over two percent. In addition, a number of organizations have forecasted real increases in coal prices of around two percent.

3.2.2 Nenana Field Coal

Unlike Beluga/Chuitna field coal, further consumption of Nenana field coal for power generation is expected to occur not at mine-mouth but rather at siting areas along the Alaska Railroad right-of-way.[a] Thus, delivered costs of coal will include rail transportation costs.

Based on discussions with M. Joseph Usibelli of the Usibelli Coal Mine, Inc., the base price of coal (1st Qt 1980 dollars) should be $1.20/MMBtu FOB rail cars at Healy or $1.43/MMBtu in 1982 dollars. The real rate of price escalation for this coal is pegged at an annual rate of two percent although information from Usibelli indicates that the rate of price increase may be lower. The real escalation of this), as measured by the producer price index, was about two percent per yea from 1965 to 1980 and at an annual rate of 4.1% from 1974 to 1980. On the other hand, a more highly mechanized dragline operation is in place and Usibelli has indicated that as equipment utilization increases as a result of higher production rates, the price may decrease about 8% at a production rate of two million TPY. The likelihood of a low or even zero price escalation is confirmed somewhat by the terms and conditions of the contracts for supply to the Golden Valley Electric Association and the Fairbanks Municipal Utility System. These contracts (which expire in 1988 and 1986, respectively) provide for cost increases indexed to a Producer Price Index (Industrial Commodities). However, price behavior at the end of this contract cannot be predicted and the 2 percent real rate for the entire forecast period is felt to be a safe assumption.

The Alaska Railroad has advised that tentative rates for scheduled unit-train movements of coal from Healy to various sites along the railroad will be as follows based on railroad arrival cars:

(a) The existing 25-MW Golden Valley Electric Association Healy plant is recognized. However, for purposes of conservative cost estimation, it is assumed that further larger scale generation sites will be located so as to avoid conflict with the Prevention of Significant Deterioration clauses of the Clean Air Act as a result of proximity to Denali National Park.

Location	$/ton (1980 basis)	Adjusted to 1982 $
Nenana	4.25	5.05
Willow K	6.50	7.72
Matanuska	7.70	9.15
Anchorage	8.90	10.57
Seward	10.00	11.88

Future costs would be subject to escalation using the Association of American Railroad's Cost Index. For purposes of this analysis it is assumed that any real transportation cost increase will be associated with fuel costs (expected to increase 2% per year), which amount to about 30% of rail haul costs. Converting to $/MMBtu, the above analysis results in the following estimated delivery price for coal supplied in year y.

Location	1982 $/MMBtu
Nenana	$0.22 + 0.09\ (1.02)^x$
Willow	$0.34 + 0.14\ (1.02)^x$
Matanuska	$0.40 + 0.17\ (1.02)^x$
Anchorage	$0.46 + 0.20\ (1.02)^x$

where $x = y - 1980$

4.0 PEAT

Peat is defined as geologically young coal. It consists of partially decomposed plant matter and inorganic materials that, over time, have accumulated in a water-saturated environment. Peat has been used as a fuel resource in Northern Europe and the Soviet Union. Other countries, including Canada, the United States, Sweden and West Germany, have active peat fuel research programs. Primarily because of the availability of lower-cost fuels, there has been little use of peat in the United States as a fuel resource. There are a number of recent and current studies to assess the resource potential and fuel availability of peat in several areas of the country, including Alaska. A preliminary resource assessment of peat in the state, and harvesting methods and costs for other locations are used to develop the information for this chapter.

4.1 AVAILABILITY

A preliminary assessment (Northern Technical Services and EKONO 1980) (EKONO 1980) of peat resources in the Railbelt identified bogs in the Matanuska-Kisitna Valley as potential sources of peat fuel, although comprehensive estimates of resources or reserves were not offered for these bogs. Information obtained indicates a lack of continuous high-quality peat resources with sulfur, nitrogen and ash content higher than Alaskan coals if compared on an energy equivalency basis. The prevailing quality problem is ash content; only 36% of the peat samples analyzed for ash had less than 25% ash content, the limit for peat fuel as specified by the U.S. Department of Energy. The study recommended further site-specific investigations in order to assess the time-energy potential of peat resources in the Railbelt.

The report considered five sites for more detailed consideration. These bogs met DOE criteria of a minimum five-foot depth, 8,300 Btu/lb dry weight, and access did not pose a significant problem. These bogs were identified as Nancy Lake West, Rogers Creek, Mile 196 West, Nancy Lake East and Stephan Lake. The information developed provides an indication of fuel quality and bog depth, but relatively little information regarding bog size. Of the bogs mentioned only about 1,000 acres of the Nancy Lake East bog were evaluated for volume and fuel quality. The total area of the Nancy Lake East bog that contains fuel-quality peat with some consistency is estimated at 3,500 acres.

The high cost of transporting peat is another factor limiting its use as a fuel. Thus, peat-fired generation units are generally proposed for bog-site operation. Given the above lack of knowledge about the resource base and overall quality of the resource, the Nancy Lake East site appears to be one of the more suitable. If the entire bog (3,500 acres) with an estimated average depth of seven feet contained fuel-quality peat, it would provide fuel for a 30 MW cogeneration plant for about 15 years. Although this is based upon less than complete information about the peat resource, it indicates that large-scale (100 MW and up) generating facilities could probably not be supported by the peat resource supplied from a single bog.

4.2 PRICE

Before a price for peat fuel is presented, it is useful to examine briefly the harvesting and fuel preparation methods. Peat harvesting is conventionally done by milling or sod methods, where only a five-to-eight-inch thick layer is removed from the bog each year. This requires that a large area be cleared and drained to provide an adequate volume of peat and a sufficient drying area. Hydraulic harvesting is an alternative method; the area to be harvested is cleared and the peat is removed by backhoe or some other mechanical means. Bog waters have a higher acidity level than surrounding lakes, rivers and streams and drainage of these waters could pose an environmental problem to the surrounding waters.

Once harvested, the peat is processed to reduce the moisture content in order to produce a suitable fuel. Current harvesting methods rely on solar and convective drying to reduce the moisture content from a level of approximately 80 to 90% in its natural state to 30 to 55%. The actual combustion requires further reduction in the moisture content to 10 to 25%, depending on the boiler configuration. This may be achieved by recirculated flue gas or hot air for pulverized (fuel peat) peat used for direct combustion.

Harvested peat may also be processed to produce pellets or briquettes. Preparation involves blending, crushing and screening of the peat prior to drying and compaction. The pellets or briquettes are of a uniform size and shape for combustion in grate-fired boilers, fluidized bed combustion systems and peat gasification systems. Another peat fuel preparation process known as wet carbonization is able to by-pass the air-drying stage and uses hydraulically harvested peat to produce a pelletized fuel.

The cost of delivered peat is dependent on both the distance required to transport the peat and the harvesting method employed. A breakdown of costs of delivered peat for various harvesting-processing operations is shown in Table 4.1. Peat, delivered over an economically short distance at 50% moisture content to an Alaskan power plant, has been estimated to cost between \$1.60 and \$4.20/10^6 Btu (EKONO, 1980). If the peat is processed into pellets or briquettes, the cost is estimated to run between \$3.40 and \$5.20/10^6 Btu.

TABLE 4.1. Cost Estimates of Peat-Based Fuels, 1980 Dollars (EKONO 1980)

Process Method	Energy Cost \$/MMBtu
Milled peat, 400,000 ton/a @ 50% moisture, bog area requirement 5,000-6,800 acres	\$1.60 - 2.30
Sod peat, 60,000 ton/a @ 50% moisture, bog area requirement 1,000-1,300 acres	2.90 - 4.20
Fuel peat, 27,000 ton/a @ 50% moisture, hydraulic/mechanical harvesting	1.95 - 2.40
Peat pellets, 30,000 ton/a @ 10% moisture, hydraulic/mechanical harvesting	3.40 - 4.80
Peat briquettes, 30,000 ton/a @ 10% moisture, bog area requirement 800-1,100 acres	4.20 - 5.20
Peat fuel from wet carbonization 250,000 ton/a @ 5% moisture, hydraulic harvesting	2.70 - 4.20

Larger milled peat harvesting operations producing 1 to 6 million tons of peat per year have been estimated to provide peat at \$0.75 to $\$1.05/10^6$ Btu. Hydraulic harvesting of one million tons per year, with mechanical dewatering and thermal drying to 50% moisture content, is estimated to cost about $\$0.83/10^6$ Btu (Punwani 1980). Such large operations would be capable of supplying fuel for 120 to 700 MW power plants. However, it should be noted that preliminary information regarding the resource base does not indicate bogs of sufficient area to sustain operations of this range in Alaska.

Because of the capital-intensive nature of harvesting and fuel preparation, escalation of peat-based fuels is expected to be connected primarily with other fuel used in the production process. The result is a relatively low escalation rate in peat fuel prices since other fuel inputs, such as diesel fuel for operating harvesting equipment, is only one of three general production inputs, i.e., capital, labor and fuel.

5.0 REFUSE-DERIVED FUEL

The analysis of refuse-derived fuel (RDF) for the Railbelt region is based upon two recent reports (Metcalf and Eddy/Engineers 1979) (Black and Veatch 1980) and with discussions held with the staff of Solid Waste Divisions of the Municipality of Anchorage and the North Star Borough. Due to the high cost of collection, consideration of RDF for electric power generation at a significant scale is necessarily limited to metropolitan areas where the sources of refuse are more concentrated. Thus consideration is given only to the Anchorage and North Star Borough solid waste disposal areas. The Anchorage area includes the Municipality, Fort Richardson, Elmendorf Air Force Base, Eagle River-Chugiak, and Turnagain Arm.

5.1 AVAILABILITY

The quantities of municipal waste available in 1980 for the two metropolitan areas were:

Anchorage	161,000 tons per year (136,000 after classification)
Fairbanks	50,000 tons per year (42,000 after classification)

Future quantities are expected to occur roughly in proportion to population in each of the areas.

One significant problem with RDF is that it is not produced at an even annual rate. For example, 1980 data for Anchorage indicate that the ratio between the peak (August) and the lowest (February) supply month is about 2:2. Since RDF cannot be stored for any considerable length of time, its use very likely must be combined with a supplemental fuel. This appears to be the concept involved in the Black & Veatch study for Fort Richardson.

The heat content of shredded and air classification RDF is typically 6,700 Btu/lb. Shredding and air classification is necessary to remove glass and ferrous and nonferrous metals that would otherwise be deleterious to furnace performance and operating reliability.

The quantities and heat content data can be placed in perspective by estimating the amount of base load power generation the RDF streams could support under annual average conditions. Based on a 80% base load plant factor, a heat rate of 12,000 Btu/kwh (low heating value solid fuels result in increased heat rates), and the above 1980 RDF quantities and heating values, the following power plant capacities are calculated:

Anchorage Area:	21.7 MW
Fairbanks	6.7 MW

Again, it is anticipated that a larger scale plant would be used and refuse would be supplemented with another fuel.

From an environmental standpoint, it may be difficult to site an RDF fired power plant within the metropolitan areas. This would impose an additional cost to the use of RDF. Although no specific data are available, RDF would be expected to contain greater percentages of sulfur and nitrogen compounds than high-quality coal.

5.2 PRICE

RDF is not assigned a price in the typical sense because it is a negative good and people are willing to pay to dispose of refuse. Disposal costs in Anchorage in 1981 of $65.28/ton of refuse include the collection and disposal at the existing shredder plant landfill. Shredder processing and landfill disposal account for about $15/ton. As mentioned aboved, the existing shredder facility would require modification in order to classify the refuse so that the fuel would be free of glass and metal objects. The Metcalf and Eddy report does not deal with the collection aspect of refuse disposal, but does provide estimates for shredding and disposal. Estimated operating and disposal costs for the current facility were stated at $19.90/ton 1980 dollars and at $14.54/ton for the modified facility. Although there was an increase in operating costs (labor, maintenance and electricity) of the modified facility, there was a greater decrease in the cost of residue removal and landfill because of the smaller volume of refuse ultimately disposed of. This results in an estimated reduction of about $5.36 in the disposal cost of refuse.

Before proceeding, the $19.90 shredding and disposal cost estimated in the Metcalf and Eddy report exceeds the $15.00 cost provided by the City of Anchorage. For purposes of estimation, it is assumed that the current $15.00 shredding and disposal cost would be reduced proportionately to the estimates in the Metcalf and Eddy study, 27 percent. The reduction of about $4.00 is then interpreted as the reduction in overall cost of refuse disposal, given that the produced RDF is used for firing a boiler and less waste material is hauled to the landfill. It must also be noted that the cost reduction does not include transporting the RDF to a boiler site. The estimated cost of moving the RDF from the shredding facility to either the Fort Richardson boiler or a new boiler located next to the Chugach Steam Generating Plant is about $3.50/ton in 1981 dollars. Given the error of estimation this approximately offsets the cost savings of disposal.

In net, the total cost of refuse collection and disposal would decrease from $65.00 to about $61.00/ton in 1981 dollars. These estimates provide a range of values for the produced RDF. The high end of the range is derived by assuming that the current collection and disposal fee of $65.00/ton is maintained. In this case, refuse producers would be indifferent to landfill disposal or the production of RDF. Thus the $4.00 cost reduction could be paid to the user of the RDF to provide an incentive to use the refuse as fuel. Although, as noted above, this amount would probably be sufficient to cover transportation of the RDF to the likely site for combustion. This then sets the minimum value of RDF at zero. The other extreme would be to assume that the RDF user would pay the full cost of collection and preparation or about $61.00/ton. This amounts to about $4.55/MMBtu. This is higher than the price of either natural gas or coal delivered to the Anchorage area.

The maximum amount a user of RDF would be willing to pay may be obtained by comparing the cost of generated electricity from another fuel and backing out the additional capital, operating and maintenance costs of a RDF-fired facility. This information is not available, but an estimate is available for conversion of the Fort Richardson boiler facility to handle RDF. Including RDF transport from the shredding facility to Fort Richardson, the cost of conversion was about $19.82/ton in 1981 dollars or about $1.50/MMBtu. This is interpreted as a penalty for refuse fuel so that its value is about \$1.50/MMBtu less than the price of competing fuels. This penalty may be less or greater, depending upon the cost of modifying other facilities (new or existing) to handle RDF.

The marginal cost of natural gas in the Anchorage area is about \$2.00/MMBtu and about \$1.70/MMBtu for coal, both in 1982 dollars. Correcting the \$1.50 penalty for RDF to 1982 dollars provides a penalty of about \$1.65/MMBtu. Given the accuracy of the estimates, the value of RDF delivered to purchasers equals zero since the boiler modification cost equals the cost of the least-cost alternate fuel. The uncertainty of firing generators with RDF may even attach a negative value to it, meaning that RDF users would accept it only if they were compensated. Provided that the same cost structure for power plant conversions for RDF utilization exist in the Fairbanks area, RDF would compete with coal which is priced at about \$1.40/MMBtu in 1980 dollars. Again, given the accuracy of the estimates RDF would have a value near zero.

Although no mention of the value of RDF was made in the Metcalf and Eddy study, several other conclusions of RDF utilization were noted.

1. The most practical and economical alternative is to convert the Fort Richardson boilers to co-firing of coal and RDF. The RDF would be produced at the municipality's shredding facility, as modified.
2. Military participation in this alternative, i.e., hauling their refuse to the municipality shredding facility , could result in slightly higher overall costs to the military bases.
3. At present, the only materials that <u>could</u> be profitably recovered from Anchorage area refuse are aluminum and computer tab cards. Most scrap iron, steel, copper, and lead in the Anchorage area is already being recycled by scrap metal brokers. The markets for other materials are too uncertain to make their recovery feasible.

Battelle's conclusions are similar but with the following additions and observations:

1. The motivation to use RDF would appear to derive principally from costs and land use problems associated with sanitary landfill disposal rather than from power generation considerations.

2. If environmental (air quality) requirements can be met for the Anchorage Air Quality Control District, conversion of the existing Fort Richardson boilers to RDF firing may be attractive, although some derating could be experienced. We note that the Fort Richardson boilers were installed in the very early 1950s and are now approaching the end of normal useful life from an electrical utility standpoint.

3. The Fort Richardson plants are cogenerators with a major function being the supply of steam space heating to the base. Electric power for civil use (off base) is incidental. Consequently, their contribution to civilian power requirements in the Railbelt would be negligible.

4. The quantity of RDF potentially available in the Fairbanks region appears inadequate to support a significant scale civil operation. Applications in the coal-fired plants (20 MW) at Fort Wainwright are a possibility but at a higher expected fuel cost.

6.0 NORTH SLOPE NATURAL GAS

This chapter examines the quantity and price of North Slope natural gas that would be available to the interior of Alaska (Fairbanks load center) via the Alaska Natural Gas Transportation System (ANGTS). Recoverable natural gas reserves in the Prudhoe Bay region are currently estimated at about 29 trillion cubic ft (Tcf), most of which lie in the Sadlerochit formation. These constitute about 11% of total U.S. recoverable reserves in comparison to the 3.8 Tcf of recoverable reserves in the Cook Inlet region. Production from Prudhoe Bay is targeted to be in the range of 2 to 2.4 Bcf/day, and the ANGTS has been designed to handle these rates of flow.

Delivery of North Slope gas to the Alaskan interior depends on the market for the gas in the contiguous United States and the completion of the ANGTS. Three important, interdependent issues will greatly influence investors' decisions to participate in the project:

- the status of gas deregulation
- the pipeline tariff structure and price of delivered gas
- the waiver package recently passed by Congress.

All three issues affect the competitiveness of North Slope gas delivered to the "lower 48".

Given that the System is completed on schedule, natural gas would begin flowing in 1986 or 1987. The interior could then expect supplies equal to at least the state's 12.5% royalty share of gas. This would amount to 91 to 114 Bcf/yr of North Slope gas available for in-state consumption.

6.1 AVAILABILITY

The availability of North Slope natural gas to the interior and the Fairbanks load center depends, first, on whether the ANGTS will be constructed and, second, on the timing of gas deliveries from the constructed system.

Portions of the gas pipeline from Prudhoe Bay to the "lower 48" are already under construction. The ANGTS is composed of five separate pieces, at least for reference purposes. These are the conditioning plant, the Alaskan segment, the Canadian segment, the Eastern leg, and the Western leg. Portions of the Canadian, Eastern and Western segments have been completed or are under construction. These segments are being completed with the intention that they will carry Canadian and other gas regardless of whether the entire system is completed.

The Alaskan segment and the conditioning plant are in question because of the cost of these portions of the line. Several estimates of the cost are available. One recent estimate shows the conditioning plant and the Alaskan segment will account for about 63% of the system's total cost of $23 billion in 1980 dollars, excluding interest and inflation (Office of the Federal Inspector 1981). The backers of the pipeline are having some difficulty raising sufficient financing to complete this portion of the project.

Prospective investors are uncertain whether North Slope gas is saleable in the "lower 48." This uncertainty is due primarily to the expected price of delivered gas and the level of gas prices in the "lower 48." The current estimate of delivered gas in 1987 is about $16/MMBtu in nominal dollars or $9/MMBtu in 1980 dollars (Office of the Federal Inspector 1981). Although rolled-in pricing is currently permitted for this gas, which makes it more attractive, it is unlikely that rolling in will be an attractive option in 1987 because of changes in gas price regulation. The current gas decontrol formula is criticized because it will result in a sharp increase in gas prices in 1985, as the decontrol formula is based on oil prices of about $16/bbl. Under the existing decontrol scheme, which is, in effect, partial decontrol, it is estimated that decontrolled wellhead prices would be about twice their controlled level--in the range of $7/MMBtu in 1985 dollars (Chemical Week July 1981) or about $5/MMBtu in 1980 dollars assuming a 7% inflation rate. The alternative complete decontrol scheme being pursued by the Reagan Administration is predicted to result in a market clearing price of about $4.50/MMBtu in 1980 dollars (Oil and Gas 1981; Stuart 1981, Platts Oilgram News 1981). Both of these prices are far below that seen for the North Slope gas. An article in Fortune (Stuart 1981) reports that there is plenty of drilling activity for deep decontrolled gas, some of which is selling at over $9/MMBtu. At the same time exploration for controlled gas is lagging, thus suggesting that there is plenty of gas to be found at prices nearer $4.50 to $5.00/MMBtu.

Backers of the ANGTS are concerned that the pipeline might not proceed under the total decontrol scenario. Given the level of prices predicted for partial or total decontrol, it is difficult to imagine that the project would proceed in either case. However, backers of the pipeline continue to seek support in order to complete the project. Several issues may give them reason for hope. The first is that the decontrol question is not settled; Congress may extend controls on gas to avoid the sharp price increases that would likely occur in 1985. This would permit the high cost North Slope gas to be rolled-in with other lower-cost supplies.

A second reason for hope is the waiver package recently passed by Congress. This package has several important provisions that could affect the willingness of investors to participate in the project. One provides for including the conditioning plant in the pipeline tariff, which would guarantee that the investment would receive the same rate of return as the rest of the pipeline and would not be subject to negotiation along with the wellhead price of gas. Another provision allows North Slope gas producers a position of joint ownership in the project. The third provision allows advance billing of "lower 48" customers for completed portions of the pipeline. This would reduce the future level of the pipeline tariff and the price of delivered gas.

The third issue centers on the pipeline tariff structure, which will have the strongest influence on delivered gas prices. The tariff could be structured such that it would be set at a low level and be allowed to increase over time rather than use a decreasing or constant schedule. However, investors might hesitate to participate under such an arrangement, because they would not realize their return in the initial years of operation and so might opt for other investment opportunities open to them.

Whether the pipeline will proceed given the existing situation is uncertain. If the pipeline does proceed, it would be capable of transporting 2 to 2.4 Bcf/day, and current permits set capacity at 2 Bcf/day. The state's 12.5% royalty share of gas would provide up to 250 MMcf/day of gas to the interior, which is viewed as sufficient to serve expected needs in the region. If the current schedule is maintained, such deliveries would begin in 1986 or 1987.

6.2 PRICE

The first year delivered price of North Slope gas to the "lower 48" is projected to be about $16/MMBtu in 1987 nominal dollars or about $9/MMBtu in 1980 dollars, including conditioning and the maximum wellhead value. Using the implied escalation rate of 8.6%, this works out to about $10.60/MMBtu in 1982 dollars. Conversations with FERC indicate two options to pricing this gas for the Alaskan market. The first is that Alaskan customers pay the full cost in service or the same price as "lower 48" customers. The second and more likely option is that the price be netted back to the Alaskan market, and Alaskan customers therefore pay less than the "lower 48" customers. This analysis assumes that the second option will be implemented and develops the net-back price and the escalation rate that would exist.

The net-back procedure first allocates the delivery fee to each segment of the line, with the gas conditioning plant at Prudhoe Bay treated as one segment. Then a mileage ratio for the Alaskan segment would be used to allocate the Alaskan portion of the tariff. Finally, the delivered price would be the sum of the wellhead price, the conditioning share of the tariff, and the mileage-based share of the tariff apportioned to the Alaskan segment.

The figures for apportioning the tariff among the five segments are listed in Table 6.1. The $10.60/MMBtu delivered price in 1982 dollars shown above includes transmission costs and the maximum wellhead value of the gas, which is $2.13/MMBtu in January of 1982; the net provides the conditioning and transmission fee of about $8.47/MMBtu. The first calculation is to assign 16% of the conditioning and transmission charge ($1.36/MMBtu) to all customers to cover the conditioning segment--the rationale being that the gas must be conditioned regardless of the point of consumption. The second calculation is to assign 47% of the total transmission charge ($3.98/MMBtu) to the Alaskan market as the Alaskan segment comprises 47% of the total ANGTS cost. This amount is then fractioned on a mileage basis to the point of delivery in-state. This analysis assumes that the point of delivery is Fairbanks, which is about 450 miles down the approximate 740 miles of the Alaskan segment. This mileage fraction, 61%, provdes for the in-state transmission fee of about $2.43/MMBTU.

TABLE 6.1 Tariff by Segment of ANGTS

Segment	Estimated Cost (Billion 1980 $)[a]	Share of Total cost
Conditioning Plant	3.6	16%
Alaskan Segment	10.8	47%
Canadian Segment	5.8	25%
Eastern Leg	1.9	8%
Western Leg	0.9	4%
	23.0	100%

(a) Excluding interest and inflation

The total of the conditioning share and in-state transmission fee provides a minimum first-year price of about $3.79/MMBtu to the Fairbanks area at a zero wellhead price, and a maximum price of $5.92/MMBtu at the maximum allowable wellhead price of 2.13/MMBtu. Local transmission and distribution would further increase this price.

The wellhead price of the gas is negotiable, but cannot exceed the maximum price established under the 1978 Natural Gas Policy Act. Under the Act, the North Slope gas price is not decontrolled in 1985 and remains constant in real terms as only escalation due to inflation is permitted.

The behavior of the price over time is dependent upon the tariff structure. For this analysis, the tariff is assumed to decline at a constant rate such that the twenty-year average tariff using this constant decay rate is equal to the twenty-year price stated in the Cost of Service analysis. A constant annual decay rate of 13.5% may then be applied to the first-year tariff ($3.79 in 1982 dollars for deliveries beginning in 1988) and the wellhead value is then added back in to obtain the delivered price. This provides for a delivered price in 2000 of $2.96 in 1982 dollars.

It should be noted that the constant decay factor tends to overstate the tariff in early years and understate it in later years. This is because typical gas pipeline tariffs decrease more rapidly in early years due to accelerated depreciation of the fixed investment. However, the constant factor used approximates the likely behavior of the price series and the inaccuracy noted is of less consequence than the uncertainty regarding the actual level of the delivered price.

7.0 NATURAL GAS LIQUIDS/METHANOL

The use of natural gas liquids (NGLs) from the North Slope has been the subject of two recent major studies, done by the Dow-Shell Group and Exxon. This chapter essentially summarizes the findings of the Dow-Shell study, which have been confirmed by public statements from Exxon in regard to its unreleased findings. The chapter first discusses the availability of NGLs and then presents the pricing scenarios that would lead to their development. The Dow-Shell study evaluates the use of NGLs with the unseparated liquefied petroleum gas (butane, propane, pentane, and other components) exported to the Gulf Coast, and the ethane component both exported and used for an in-state petrochemical industry.

7.1 AVAILABILITY

Recoverable reserves of NGLs from North Slope fields are currently estimated at about 400 million barrels and natural gas reserves at about 29 Tcf. The Dow-Shell study outlined plans for extracting natural gas at 2.7 Bcf/day, of which 210,000 barrels of liquid would be available for shipment in an NGL pipeline. ANGTS has a planned capacity of 2 to 2.4 Bcf/day.

The production of NGLs is outlined in two phases. In the first phase total NGL production would be 165,000 Bbl/day, with the production of ethane increasing from 45,000 to 90,000 Bbl/day in the second phase to bring production up to 210,000 Bbl/day. The remaining quantities of LPG gas, are 61,000, 34,000, and 28,000 Bbl/day for propane, butanes and pentanes, respectively, with no change in the in-production level from phase one to phase two. The ethane component of the NGLs is the most important to Alaska for a petrochemical industry and would be used to produce ethylene, an important chemical feedstock. It is estimated that by the late 1980s demand in the Pacific Rim markets will be sufficient to absorb the additional supply of NGLs.

Plans outlined in the Dow-Shell study contain three basic options. The first is to extract and export all the NGLs to outside markets for further processing. The second is to establish a petrochemical industry in Alaska that would produce low capital-intensive and high-ethane-content based products such as polyethlene and alpha olefins. The third would be to establish a petrochemical industry that would produce relatively high capital-intensive and low-ethane-content based products such as ethylene glycol, ethylene dichloride and ethylbenzene. The LPG components would not be processed in Alaska in either of the petrochemical scenarios; rather, they would be exported to the Gulf Coast market. The Dow-Shell study concludes that the second option is best suited for Alaska.

The timing of all three options is tied to the price of crude oil and the development of the ANGTS. The impact of the price of oil on the feasibility of utilizing NGLs from the North Slope will be addressed in the next section; however, a real increase in world crude oil prices is necessary for the utilization of gas liquids. Potential participants in an NGL venture feel that the infrastructure in Alaska could not support the construction of both the ANGTS and NGL system at the same time. In addition, the likely cost increase that would occur in both projects due to resource acquisition problems would render them financially unfeasible if both were undertaken at the same time. Given this information and the tentative current construction schedule for the ANGTS, which is due to be completed in the late 1980s, the NGL system would not be completed until the mid-to-late 1990s.

Production of methanol was also considered in the Dow-Shell study by Alaska Interior Resources, Inc. The timing of a methanol facility depends on the ANGTS; since methane from the North Slope would serve as the feedstock, methanol production would begin in the late 1980s with the projected completion of the ANGTS. The feasibility study concluded that methanol produced from methane would be more economical than that produced from coal. The 5,000 metric ton per day facility would require about 175 MMcf of methane per day.[a] This amount is less than the state's royalty share of North Slope gas of 250 MMcf/day at a flow rate of 2 Bcf per day.

(a) Based on a personal communication with Mr. Bob Dempsey of Alaska Interior Resources, Inc. that indicated 1 short ton of methanol contains about 19.5 to 20 MMBtu and the conversion efficiency, i.e., Btu feedstock input to methanol Btu content, is in the range of 60 to 65%.

7.2 PRICE

The financial feasibility of extracting and marketing NGLs separately from the gas stream depends primarily on the price received for the LPG components and would require only slight increases in the price of crude oil. The feasibility of further separating the ethane component for use in a petrochemical venture would require a more substantial increase in the price of oil.

The Dow-Shell study reports that the NGL venture would be viable with a rise in crude oil prices to about $40/bbl or greater in real terms (1981 dollars), in absence of completion of the ANGTS. Given the current level of oil prices, about $36/Bbl, the project's feasibility would be dependent upon the real escalation of crude oil prices as shown in Table 7.1.

TABLE 7.1 Crude Oil Price Sensitivity to Escalation Rate

	Real Escalation Rate		
Year	1%	2%	3%
1980	$36.00	$36.00	$36.00
1985	$37.84	$39.75	$41.73
1990	$39.77	$43.88	$48.38
1995	$41.79	$48.45	$56.09
2000	$43.93	$53.49	$65.02

Without ANGTS the production of NGLs appears to be feasible as early as the mid-1980s with a 2% to 3% real annual escalation rate. If ANGTS is constructed, the study states that the real price of crude oil would have to exceed $52/bbl, which would delay the NGL system into the mid-to-late 1990s with a 2% to 3% real escalation rate. A 1% real escalation in oil prices delays the feasibility of an NGL system beyond the year 2000.

The Dow-Shell study provided the following estimates of the Alaska tidewater value of ethane and the LPG components corresponding to two world oil prices:

	Crude Oil Price, 1981 $/Bbl	
	37.50	55.00
LPG, $/lb	.081	.139
Ethane, $/lb	.052	.111

Interpolating provides an estimate of the tidewater value of the product corresponding to the two feasibility scenarios outlined above, i.e., LPG without ANGTS at $40/Bbl and LPG with ANGTS at $52/Bbl in 1981 dollars.

	Without ANGTS (Crude $40/Bbl)	With ANGTS (Crude $52/Bbl)
LPG, $/lb	.089	.129
Ethane, $/lb	.060	.101

These prices represent the estimated tidewater value of these products as outlined in the feasibility study with and without the ANGTS.

Methanol production costs and methanol prices were not mentioned in the Dow-Shell feasibility study, nor was this information directly obtainable from the study's participants. However, it was indicated that the methanol produced would be competitive on the West Coast markets with the methane feedstock priced at its maximum legal value.[a] Recent methanol prices quoted in Chemical Weekly have been in the range of $.90 to $1.00 per gallon, or about $14.06 to $15.63 per MMBtu.[b] This provides a net-back price to tidewater Alaska of about $13.29 to $14.86 per MMBtu with a $2.00 per Bbl transportation cost to the West Coast--compared to the projected cost of methane input at Fairbanks of about $5.92 per MMBtu. This suggests that production and transportation costs to tidewater are no greater than about $7.34 to $8.91 per MMBtu.

(a) Personal communication with Mr. Bob Dempsey of Alaska Interior Resources, Inc.
(b) Based on 64,000 Btu/gal.

8.0 FUEL OIL

The use of fuel oil for electricity generation is generally regarded as a last-choice alternative because of its high cost. Generally, oil is used only for peaking capacity. The Railbelt region conforms to this usage pattern, although the northern portion of the Railbelt and remote sections of Alaska depend heavily upon fuel oil for their electricity needs.

Given the current outlook for future oil prices, as determined by OPEC, it is unlikely that oil will continue to figure heavily as baseload generating fuel in the electricity generating plans for the Railbelt. This is aided by the availability of lower cost natural gas and abundant supplies of coal and hydroelectric sites, all of which promise relatively low-cost electricity production.

8.1 AVAILABILITY

Although Alaska is currently not self-sufficient in refined petroleum products, the availability of refined products over the forecast period appears to present little problem. Recoverable reserves are estimated at about 8 billion barrels as of January 1981, with about 993 million barrels of this being state royalty oil. This quantity of royalty oil is sufficient to cover projected cumulative consumption of about 929 million barrels (Goldsmith and O'Connor 1980) through the year 2000. Beyond this period, consumption can likely be supplied by one or more of the following: an increase in the quantity of recoverable reserves and royalty oil; diversion/purchase of nonroyalty oil for in-state use; and out-of-state purchases from either foreign or "lower 48" producers.

An estimate of Alaska's 1979 import dependence by petroleum product is shown in Table 8.1. This information indicates that imports accounted for about 37% of in-state consumption in that year. This dependence varies by product from about 30% for motor gasoline to 100% for aviation gasoline. Given no increase in in-state refinery capacity, this dependence on imports will grow.

TABLE 8.1 Alaska Consumption of Imports and Exports of Refined Petroleum Products in Barrels/Day, 1979

Product	Consumption	Exports	Imports
Motor Gasoline	12,360	—	3,810
Aviation Gasoline	1,102	—	1,102
Jet Fuel	27,007	—	10,102
LP Gas	334	—	0
Medium Distillates	33,978	—	12,860
Residual Fuel	0	18,874	0
TOTAL	74,781	18,874	27,874

SOURCE: Department of Commerce and Economic Development. April 1981 (Draft). State of Alaska Long-Term Energy Plan. Department of Commerce and Development, Division of Energy and Power Development, Anchorage, Alaska.

The Alaska Department of Natural Resources (1982a; 1982b) has solicited proposals for the purchase of royalty oil for in-state processing or supply of petroleum products. Three contracts have been submitted to the state legislature for final approval. One is with Tesoro for about 46,000 barrel per day (b/d) over a 12-year period. Current plans for refining this oil are to use existing capacity and Tesoro will continue to evaluate expanding its in-state refinery capacity. This contract has received legislature approval and deliveries to Tesoro are to begin in January of 1983.

The other two contracts are with Doyon. The first of these contracts is for about 19,000 b/d for a 12-year term contingent upon the construction of a refinery in Fairbanks by December of 1983. This contract has also received legislative approval on the condition that Doyon submit a financial plan for the proposed refinery by October 1, 1982. The second contract for about 17,000 b/d for a 12-year term is no longer in effect. This contract was contingent upon Doyon acquiring a controlling interest in the Mapco refinery by May 1, 1982 and this condition was not met.

Three other contracts are in some stage of consideration. The first is based on an offer by the State to Chevron for about 38,000 b/d of royalty oil, with about 18,000 b/d to be processed in state at Chevron's Nikiski refinery and the remainder to be processed by Chevron in California and returned to Alaska in finished products. The second is with Alaska for up to 15,000 b/d for 10 years in exchange for petroleum coke to blend with coal exports from the Usibelli mine to Korea. The third is with Provident for up to 50,000 b/d for 20 years to be exported and refined for sale in Arizona.

8.2 PRICE

This section develops the prices for fuel oil in Fairbanks and Anchorage areas. These prices are developed separately because of the differences in location and demand requirements, both of which affect the price of the oil purchased. Oil price escalation is handled separately because of its importance with regard to future prices.

Anchorage Municipal Power and Light purchases No. 2 oil for winter peaking purposes. The last purchase of oil was in December 1980 at a price of $.959/gal or about $6.92/MMBtu. The price of this oil is not expected to have changed significantly over the last year in view of the stability of world oil prices during the last year and the prices of this and similar products in the Fairbanks area.

Three grades of fuel oil and their respective heat content are identified for electricity generation and space heating in the Fairbanks area.

No. 1 and No. 2 heating/diesel fuel	5,825 MBtu/bbl
No. 6 heavy turbine fuel	5,922 MBtu/bbl

Delivery and prices of these fuels have been set by contract between the North Pole Refinery and its utility customers, the City of Fairbanks and the Golden Valley Electric Association (GVEA).

The contract with GVEA was effective on May 1, 1980, and runs for 7 years. This contract contains a provision for price escalation at the world rate and establishes a formula for computing the price of the turbine fuel. No. 1 and 2 fuel oil prices are set equivalent to the lowest price given to other customers, so the prices paid by GVEA are linked to those paid by the City of Fairbanks.

Table 8.2 shows the prices for each of the fuels to each of the buyers. The prices to Fairbanks are those stated in the contract. The price of turbine fuel to GVEA is the price being paid in November 1981. There is not a great deal of difference in these prices because there has been virtually no change in the world oil price over this period. The price of No. 1 and 2 oil to GVEA is assumed to be equal to that for the City of Fairbanks.

TABLE 8.2 Fuel Oil Price in Fairbanks, 1980-81

Fuel Type	City of Fairbanks (Nov.1980) $/Gal	City of Fairbanks (Nov.1980) $/MMBtu	GVEA (Nov.1981) $/Gal	GVEA (Nov.1981) $/MMBtu
No. 1 Diesel Fuel	.946	6.82	NA	NA
No. 2 Heating/Diesel Fuel	.893	6.44	NA	NA
No. 6 Heavy Turbine Fuel	.863	6.12	.82	5.92

The market price of Alaska North Slope and other domestic crude oils is now directly tied to world oil prices adjusted for transportation costs, as these represent the marginal cost of supply. What future world oil prices will be is highly speculative given the influence of the Organization of Petroleum Exporting Countries (OPEC).

The approach taken in this analysis of future crude oil price behavior is to examine the recent literature on the subject and draw a consensus forecast. Table 8.3 summarizes the real price escalation rates for crude oil from a variety of sources. These sources and others indicate a range of real price escalation from 0% to 3%, with a 1% to 3% range for the longer term. Some sources and recent experience indicate that a negative escalation over the short term is also a possibility. Also, it is reported that OPEC is seeking to maintain a 3% real rate of price increase. All of the sources, including OPEC and others, think it unlikely that price increases will exhibit a smooth rate, but rather a series of sharp jolts as experienced in the past.

This analysis selects a 2% real long-term rate of increase for the base case with a high and low of 3% and 1%, respectively, for the range. In addition to the consensus from the above sources, there are a number of other reasons for this selection. Real price increases of greater than 3% are unlikely because past increases have dramatically changed the relative price of fuels. This has led to energy conservation measures and the substitution of other fuels for oil products. These measures have helped to restrain recent price increases contemplated by OPEC. The change in relative prices also increases the development and commercialization of alternative energy-producing technologies and oil recovery methods. OPEC is mindful that their product may be displaced from the market if too large and too rapid a shift in relative energy prices takes place. On the other hand, OPEC appears able to prevent a decline in real prices over the long term.

TABLE 8.3. Expected Real Price Escalation Rates for Crude Oil

Time Period	Real Annual	Source
1980-1990	3%	Patrick J. Keenen, Vice President, Energy Economics, Chase Manhattan Bank, Platts Oilgram News, Oct. 14, 1981.
1980-2000	3%	Standard Oil of California, Platts Oilgram News, August 4, 1981.
1980-2000	1-2%	Texaco, Oil and Gas Journal, Sept. 28, 1981.
1980-1985	0-1%	Bankers Trust, Oil and Gas Journal, Sept. 28, 1981.

Given the current crude price of about $36/bbl, the real and nominal prices of oil over the forecast period are listed in Table 8.4. The effect of just the real escalation rate on oil price in constant dollars is rather dramatic, giving a range of $47 to $82/bbl by the end of the forecast period for the 1 and 3% real escalation rates, respectively. This effect is more startling when the oil prices are viewed in nominal dollars where both inflation and real escalation are reflected in the price.

TABLE 8.4. Oil Prices Over the Forecast Period, $/Bbl

Year	1982 Dollars			Nominal Dollars, 7% Inflation Rate		
	1%	2%	3%	1%	2%	3%
1982	36.00	36.00	36.00	36.00	36.00	36.00
1990	38.98	42.18	45.60	66.98	72.47	78.36
2000	43.06	51.42	61.29	145.54	173.79	207.15
2010	47.57	62.68	82.37	316.26	416.73	547.63

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APPENDIX A

SUMMARY DATA ON COOK INLET NATURAL GAS FIELDS

DISCOVERY DATE: 2/10/67

FIELD OR UNIT: Beaver Creek

INITIAL PRODUCTION: 1/73

LOCATION: Kenai Peninsula

WELLS FLOWING: 1 SHUT IN: 0

STATE ROYALTY: 0%

PRODUCTION 1979: Net .00925 BCF

CUMULATIVE PRODUCTION 1/1/80: Net 0.463 BCF

OPERATOR: Marathon Oil Co.

OTHER PARTICIPANTS: Union Oil Co.

ESTIMATED REMAINING RESERVES: 240 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 240 BCF, DATE: 1/1/80

REMARKS:

1. No gas pipeline connection
2. One injection well

CONTRACT PROVISIONS.

Expired contract with Pacific Alaska LNG Associates reported for commitment of 111 BCF. May be being renegotiated.

DISCOVERY DATE: 12/18/62

FIELD OR UNIT: Beluga River

INITIAL PRODUCTION: 1/64

LOCATION: W. Side Cook Inlet (Onshore)

WELLS FLOWING: 6 SHUT IN: 0

STATE ROYALTY: 7.99% in value

PRODUCTION 1979: 16.99 BCF

CUMULATIVE PRODUCTION 1/1/80: 90.46 BCF

OPERATOR: Chevron USA, Inc.

OTHER PARTICIPANTS: Shell Oil Co. (33%)
Atlantic Richfield (33%)

ESTIMATED REMAINING RESERVES: 767 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE
Chugach Electric Assoc.	373	Original Contract
Chugach Electric Assoc.	310 (1)	1/1/80
Pacific Alaska LNG Assoc.	624	11/5/75 (2)

UNCOMMITTED REMAINING RESERVES: Negative BCF, DATE: 1/1/80

REMARKS:

1. Estimated by deducting cumulative sales to 1/1/80 from original contract commitment.
2. DeGolyer and MacNaughton estimate date 12/10/75. Estimate of reserves committed to others (Chugach) given as 352 BCF as of 11/5/75.

CONTRACT PROVISIONS:

Chugach Electric Association

Original Commitment: 373 BDF or until 1/1/98 which ever occurs first.

Delivery Obligations MMcf/day:

	Maximum Take	Minimum Take
1973	30	9
1974	30	18
1975	30	18
1976	35	30

BELUGA FIELD (continued)

CONTRACT PROVISIONS:

	Maximum Take	Minimum Take
1977	50	30
1978	50	40
1979	60	40
1980	60	50
1981	60	50
1982 on	60	55

Price:

	Without Pacific Alaska LNG Purchases ¢/Mcf	With Pacific Alaska LNG Purchases ¢/Mcf
1977	17.64	-
1978	18.64	-
1979	19.20	-
1980	19.62	-
1981	19.62	-
1982	20.03	-
1983	20.62	-
1984	21.03	-
1985	21.03	84.78
1986	21.45	86.45
1987	21.45	91.22

Pacific Alaska LNG Associates

			Estimated Reserves
Execution Dates:	Chevron	7/15/77	220.8 Bcf
	Shell	7/11/77	na
	ARCO	6/30/77	220.4 Bcf

Terms: Commits all gas in excess of commitments to Chugach Electric Association, 20 years.

Price: $1.48/Mcf as of 1/1/78, 1¢/quarter escalation

DISCOVERY DATE: 6/9/65

FIELD OR UNIT: Birch Hill

INITIAL PRODUCTION: na

LOCATION: Kenai Peninsula

WELLS FLOWING: 0 SHUT IN: 1

STATE ROYALTY: 0%

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: 0.1 BCF

OPERATOR: Chevron USA

OTHER PARTICIPANTS: Atlantic Richfield

ESTIMATED REMAINING RESERVES: 11 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 11 BCF, DATE: 1/1/80

REMARKS:

1. Semi-remote field four miles north of Swanson River Field.
2. Closest pipeline is 16" line from N. Cook Inlet gas field to Nikiski.

CONTRACT PROVISIONS:

None

DISCOVERY DATE: na

FIELD OR UNIT: Cannery Loop

INITIAL PRODUCTION: na

LOCATION: 3 mi East of Kenai

WELLS FLOWING: na SHUT IN: na

STATE ROYALTY: na

PRODUCTION 1979: na BCF

CUMULATIVE PRODUCTION 1/1/80: na BCF

OPERATOR: Union Oil Co.

OTHER PARTICIPANTS: Marathon
Pacific Lighting

ESTIMATED REMAINING RESERVES: na BCF, DATE: -

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: ______ BCF, DATE: ______

REMARKS:

1. Potential discovery, one well. Confidentiality release date is July 24, 1981.

CONTRACT PROVISIONS:

None

DISCOVERY DATE: 6/25/61

FIELD OR UNIT: Falls Creek

INITIAL PRODUCTION: na

LOCATION: E. Side Cook Inlet (On & Offshore)

WELLS FLOWING: 0 SHUT IN: 1

STATE ROYALTY: 0

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: <0.1 BCF

OPERATOR: Chevron USA, Inc.

OTHER PARTICIPANTS:

ESTIMATED REMAINING RESERVES: 13 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 13 BCF, DATE: 1/1/80

REMARKS:

1. Remote field

CONTRACT PROVISIONS:

None

DISCOVERY DATE: 10/8/66

FIELD OR UNIT: Ivan River

INITIAL PRODUCTION: n.a.

LOCATION: W. Side Cook Inlet (onshore)

WELLS FLOWING: 0 SHUT IN: 1

STATE ROYALTY: 12.5%

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: 0 BCF

OPERATOR: Chevron USA, Inc.

OTHER PARTICIPANTS: Atlantic Richfield (37.5%)
Pacific Lighting (12.5%)

ESTIMATED REMAINING RESERVES: [illegible]6 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE
Pacific Alaska LNG Assoc.	105.9	11/1/75

UNCOMMITTED REMAINING RESERVES: 0 BCF, DATE:

REMARKS:

1. DeGolyer & MacNaughton estimated recoverable reserves at 105.9 BCF as of November 1, 1975.
2. No pipeline connection. Located approximately 9 miles NE of Beluga gas field.

CONTRACT PROVISIONS:

Executed:

ARCO: June 30, 1977
Pacific Lighting: August 30, 1977
Chevron USA: July 15, 1977

Term: 20 years

Price: $1.[illegible]6/Mcf July 1, 1977, escalated 1¢/quarter. If deregulated escalate by producer price index (from 195.2 as of May, 1977)

Railbelt Electric Power Alternatives Study: Fossil Fuel Availability and Price Forecasts

Volume VII

March 1982

Prepared for the Office of the Governor
State of Alaska
Division of Policy Development and Planning
and the Governor's Policy Review Committee
under Contract 2311204417

Battelle
Pacific Northwest Laboratories

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RAILBELT ELECTRIC POWER ALTERNATIVES STUDY: FOSSIL FUEL AVAILABILITY AND PRICE FORECASTS

Volume VII

T. J. Secrest
W. H. Swift

March 1982

For the Office of the Governor,
State of Alaska,
Division of Policy Development and
Planning, and the Governor's
Policy Review Committee
under Contract 2311204417

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PROLOGUE

The State of Alaska commissioned Battelle to investigate potential strategies for future electric power development in Alaska's Railbelt region. The results of the study will be used by the Office of the Governor to formulate recommendations for electric power development in the Railbelt.

The primary objective of the study is to develop and analyze several alternative long-range plans for electric energy development in the Railbelt region (see Volume I). Each plan is based on a general energy development strategy representing one or more policies that Alaska may wish to pursue. The analyses of the plans will produce forecasts of electric energy demand, schedules for developing generation and conservation alternatives, estimates of the cost of power, and discussions of the environmental and socioeconomic characteristics for each plan.

This report (Volume VII of a series of seventeen reports listed below) addresses the availability and price of fossil fuels over the forecast period 1980-2010 for the Railbelt region. Each of the chapters corresponds to individual working papers for the respective fuels. The first of these was completed in February of 1981 and the last was completed in November of 1981. The costs and fuel prices in the working papers were adjusted to beginning of year 1982 dollars for this final report using the GNP implicit price deflator.

At the time the fuel price forecasts were assembled (1981 calendar year), they reflected the main body of expert opinion concerning future world petroleum prices, providing for real price escalation in the range of 1% to 3% per year over the long term. Since that time, the market conditions for oil have changed and there is no longer a strong consensus on the behavior of future oil prices, although the predominant belief is for a lower level of price escalation than existed even a year ago. Industry sources are now forecasting annual real price increases for the 1980s ranging from minus 3.3% to plus 2.8%, with low probability political crises possibly resulting in higher rates of increase (Oil and Gas Journal 1982a). Two recent forecasts (Standard Oil of California June 1982, Data Resources, Inc. Summer 1982) predict a long-term real annual rate of increase in the range of 0% to 2% to the end of the century. Although Alaska Department of Revenue's oil price forecasts are clearly lower than a year ago, they also have been subject to considerable uncertainty. The Department's long-term annual real escalation rates fell from about 2% in June of 1981 to negative 1% in March of 1982, but then rose to negative .2% by June of 1982. The price forecasts for the other fuel types were constructed with the recognition of the institutional as well as market factors that would likely affect their behavior.

A number of events have taken place that may affect the availability and prices of other fuels. The PacAlaska project has commitments for about two-thirds of needed gas supplies (Oil and Gas Journal, 1982b). The project sponsors are optimistic about receiving a favorable ruling in late 1982 on the LNG terminal to the located in California but expect an additional two-year delay over environmental issues. The reported 1.6 Tcf of gas needed for this project will have an impact upon the market for natural gas in the Cook Inlet region. The ANGTS pipeline has been delayed until at least 1989, thus limiting the availability of North Slope gas to the Interior. This delay also delays the schedule for possible methanol production since the North Slope gas was to be the feedstock for the methanol facility.

RAILBELT ELECTRIC POWER ALTERNATIVES STUDY

Volume I - Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans

Volume II - Selection of Electric Energy Generation Alternatives for Consideration in Railbelt Electric Energy Plans

Volume III - Executive Summary - Candidate Electric Energy Technologies for Future Application in the Railbelt Region of Alaska

Volume IV - Candidate Electric Energy Technologies for Future Application in the Railbelt Region of Alaska

Volume V - Preliminary Railbelt Electric Energy Plans

Volume VI - Existing Generating Facilities and Planned Additions for the Railbelt Region of Alaska

Volume VII - Fossil Fuel Availability and Price Forecasts for the Railbelt Region of Alaska

Volume VIII - Railbelt Electricity Demand (RED) Model Specifications

Volume VIII - Appendix - RED Model User's Manual

Volume IX - Alaska Economic Projections for Estimating Electricity Requirements for the Railbelt

Volume X - Community Meeting Public Input for the Railbelt Electric Power Alternatives Study

Volume XI - Over/Unaer (AREEP Version) Model User's Manual

Volume XII - Coal-Fired Steam-Electric Power Plant Alternatives for the Railbelt Region of Alaska

Volume XIII - Natural Gas-Fired Combined-Cycle Power Plant Alternative for the Railbelt Region of Alaska

Volume XIV - Chakachamna Hydroelectric Alternative for the Railbelt Region of Alaska

Volume XV - Browne Hydroelectric Alternative for the Railbelt Region of Alaska

Volume XVI - Wind Energy Alternative for the Railbelt Region of Alaska

Volume XVII - Coal-Gasification Combined-Cycle Power Plant Alternative for the Railbelt Region of Alaska

November 1982

SUMMARY

This paper addresses the availability and price of fossil fuels over the forecast period 1980-2010 for the Railbelt region.

The assessment of fuel availability considers only the in-state resource base as the supply source for two reasons: either the available resource is sufficient to supply Alaska's needs, or the cost of transporting fuels to Alaska's markets is such that in-state substitutes will be available. The Cook Inlet natural gas resource is the only fuel that may be inadequate to supply the needs of the southern part of the Railbelt region over the time horizon of the study, given no additional major finds. This gas could be supplemented with high-cost liquefied natural gas (LNG) imports, but then coal, oil, and North Slope gas become reasonable substitutes.

When a current price for a fuel is not available, the concept of opportunity cost is used to develop the base price and forecast. This concept provides that the resource price is equal to the price the resource will command in an alternative market, less the appropriate transportation and handling fees. Alaska is familiar with this net-back method of price determination, which is currently used for valuation of their royalty gas and oil resources. Table 1 and Figure 1 summarize fuel availability and prices faced by the electric utilities for the forecast period.

COOK INLET NATURAL GAS

The supply and price of Cook Inlet natural gas is the most complex of all the Railbelt fuels because contracts have established the quantity, current price, and price escalation rate for various portions of the gas, and the terms of these contracts differ. In addition, new or incremental supplies used to meet demand in excess of the contracted supply are priced by their opportunity value, which is the net-back from liquid natural gas (LNG) sales to Japan. Determining price for Cook Inlet gas requires a forecast of both price and quantity from each contractural source to develop the weighted average gas price for the region. The result of this forecasting is a price escalation that is not smooth over the forecast period. This uneven price

TABLE 1. Fossil Fuel Availability and Price

Fuel Type	Estimated Reserves	Availability	Price/10^6 Btu (January 1982 $'s)	Annual Real Escalation Rate
Coal				
Beluga/Cook Inlet	350×10^6 tons	1988	1.48 Mine Mouth	2.1%
Healy/Interior	240×10^6 tons	Present	1.75 Delivered Nenana	2.0%
Natural Gas				
Cook Inlet[a]	3,900 Bcf	Present	0.86 City Gate	6.6% avg
North Slope/Interior	21,500 Bcf	1987	5.92 City Gate	-4.3% avg
Liquids/Methanol	3,800 Bcf	1995		
No. 2 Heating Oil	Adequate	Present	6.90 Delivered	2%
Peat	N/A	1988	(b)	1%
Refuse-Derived Fuel				
Anchorage	--	1985	--	--
Fairbanks	--	1988	--	--

(a) Volume weighted average price to Alaska Gas and Service and Chugach Electrical Association.
(b) Estimates range from 1 to 3 times the price of coal.

escalation is evidenced in Figure 1 by the relatively constant price of gas from 1980 to 1985, and the escalation over the rest of the period, with stepped increases occurring in 1990 and 1995 when major contracts expire. After 1995, the price and escalation rate of gas are determined by its opportunity value because current purchase contracts will have expired. The price of natural gas then is assumed to escalate at a rate approximately 2% faster than inflation--the same real annual rate as for oil. Current information about Cook Inlet natural gas reserves and total demand on those reserves indicates that availabilty to the Alaskan market could become a major problem as early as 1990, and almost certainly after the year 2000.

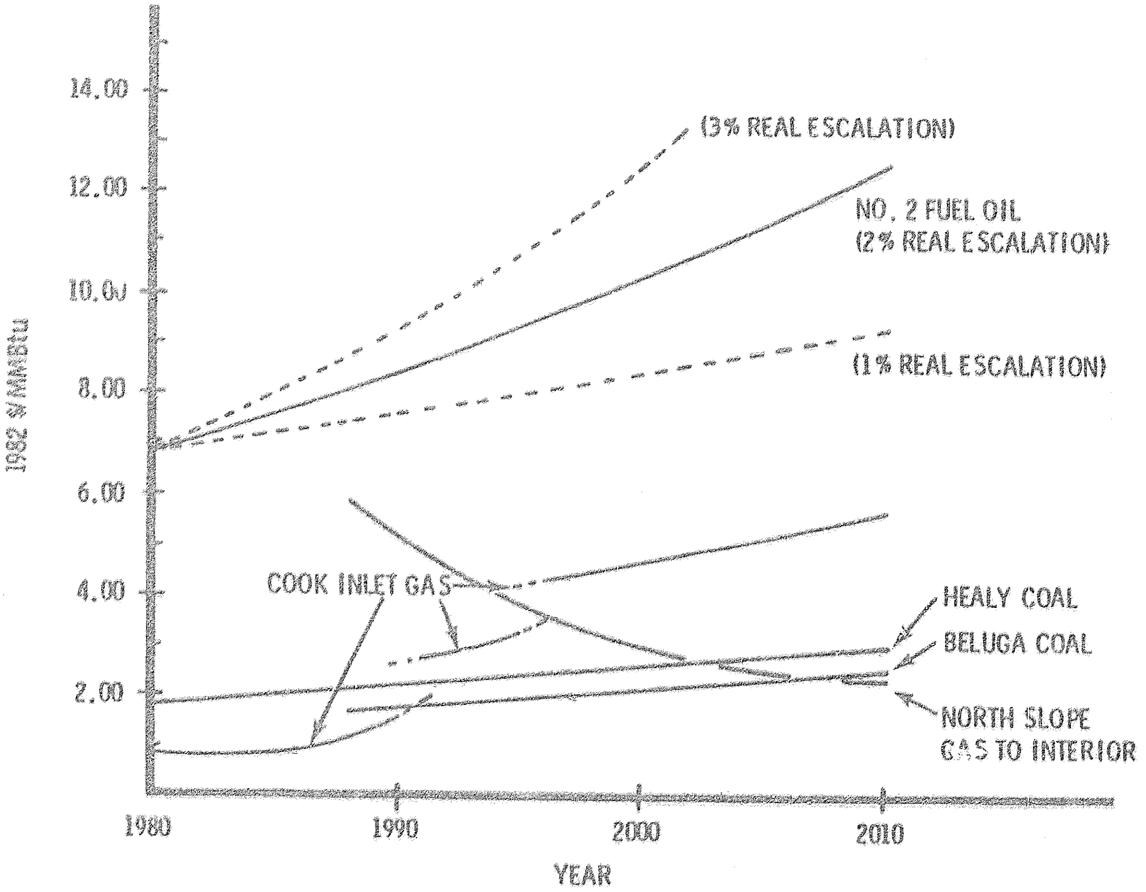

FIGURE 1. Projected Fuel Prices to Railbelt Utilities, 1982 $/MMBtu, 1980-2010

COAL

Two sources of coal are available to the Railbelt. The Usibelli mine located at Healy is the only mine curently producing coal in significant quantities. The cost of this coal is assumed to escalate in real terms at the real historical rate of about 2% per year. A second potential source is the Beluga coal field, which has been targeted as a source of supply for the Anchorage area and as export to markets on the Pacific Rim. As discussed below, this field may enter production about 1988. Beluga coal is expected to escalate at the same rate as other coal supplies serving the Pacific Rim export market at a real rate of about 2.1% annually.

Note that a great deal of uncertainty is involved in developing the Beluga coal fields. These coal fields are now in the exploratory and predevelopment phase. The coal has yet to be produced in any significant quantity and thus, from an availability standpoint, must be considered prospective. Located in an area with very little to no infrastructure development, these fields, while containing very large reserves, are not likely to produce coal unless a firm market of five or more million tons per year can be established. As a result, the establishment of an export market is a necessary precursor to the availability of Beluga coal for in-state use.

PEAT

Alaska has substantial peat reserves, although these reserves have not been comprehensively assessed. The peat resource is assumed not to be developed before Beluga coal. Although information for peat development in Alaska is lacking, a preliminary feasibility study (EKONO 1980) estimates a range of likely prices from about 1 to 3 times the price of coal on a Btu basis, depending upon the harvesting and processing method used. The only real escalation likely to occur is that associated with transportation and handling, set at less than a 1% real annual rate.

Based upon current resource information and existing steam-electric generating technology, peat does not appear to be a competitive fuel for electrical generation in the Railbelt. However, because of the extensive peat resources available within the area, it appears to warrant further investigation as technologies to use peat are further developed.

REFUSE-DERIVED FUEL

The refuse-derived fuel (RDF) resource is limited to the two municipalities of Anchorage and Fairbanks. The resource has three problems: 1) limited availability, requiring RDF to be mixed with other fuels for electricity generation, 2) seasonality (more refuse is generated in the summer than in the winter), and 3) limited storage life. However, it has two offsetting factors: 1) zero cost, since people place no value on refuse and disposal costs already exist to refuse producers, and 2) the only real escalation expected is in transportation and handling. A limited amount of RDF generation appears feasible.

NATURAL GAS INTERIOR

The North Slope reserves of natural gas are sufficient to supply the Alaska Natural Gas Transportation System (ANGTS) to capacity (2 to 2.4 Bcf/day, for the forecast period. This gas may begin flowing in 1986 or 1987. If only Alaska's royalty share is diverted to serve the Fairbanks area, the supply of gas would be about 100 Bcf/year. A current estimate of the delivered price of gas to the "lower 48" is about $10/MMBtu in 1982 dollars, with the January 1982 maximum wellhead price of $2.13/MMBtu. The net-back provides a first year delivered city gate price to Fairbanks of about $5.92/MMBtu in 1982 dollars. This gas is not scheduled to decontrol under existing law and descalates with the pipeline tariff.

NATURAL GAS LIQUIDS/METHANOL

The delivery of natural gas liquids (NGLs) to the Railbelt depends on the construction schedule of the ANGTS and the real price of crude oil. Current plans call for construction of an NGLs pipeline following the ANGTS, with a real crude oil price in the range of $50 to $52/barrel. This schedule provides for delivery of NGLs in the mid-to-late 1990s.

Methanol production is tied closely to the ANGTS because the natural gas from that system would serve as the feedstock, but the timing of methanol production appears to be tied to petrochemical production that may accompany the NGL pipeline. Current methanol prices in the "lower 48" have been in the range of $0.90 to $1.00/gal. The net-back price at Alaska tidewater would range from $0.85 to $0.95/gal or $13.29 to $14.86/MMBtu. This price must incorporate Fairbanks' city gate price for the methane feedstock of ~$5.92/MMBtu, suggesting that the production and transportation costs from Fairbanks to tidewater can be no greater than $7.34 to $8.91/MMBtu. Currently, methanol production is not cost competitive with other fuels in the "lower 48" and is not projected to become cost competitive until after the year 2000.

FUEL OILS

Refined petroleum products are the only fuels in which Alaska is currently not self-sufficient. This is because of insufficient refinery capacity for some products, rather than lack of resources. Alaska's royalty share of crude oil production is sufficient to meet in-state consumption at least through the year 2000, but some refined products are imported. The supply of petroleum products is not believed to be a problem through the forecast period, however. The current price of utility fuel oil of ~$6.90/MMBtu is a good indicator of its current opportunity value, especially in view of the recent price decontrol on oil. This oil is expected to escalate at a 2% annual real rate along with crude oil. Figure 1 also shows the price of No. 2 oil over the forecast period for real annual escalation rates of 1% and 3%.

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1.0 INTRODUCTION

The Railbelt Electrical Power Alternatives Study is being conducted for the Office of the Governor, State of Alaska, by Battelle, Pacific Northwest Laboratories. Task 1 of the study addresses the future availability and prices of various fuels. The fuels considered are those that are, or could be, used in the generation of electric power or, at the consumer level, provide a substitute. These are coal, oil and natural gas. Two supplemental fuels, peat and municipal waste, are also considered.

Location within the Railbelt region is also a determinant of the future availability and price of the various fuels. Thus, in essentially all cases, the analyses will consider the Cook Inlet and Fairbanks-Tenana Valley regions separately. This is especially important for natural gas, as it is currently available in only the Cook Inlet region and future availability of supply is an area of concern. North Slope gas may be available in the Fairbanks area as early as 1986, but there are no existing plans to pipe this gas to the Cook Inlet region. The price of gas in these two regions differs significantly because Cook Inlet prices were initially established in a buyer's market with long-term contracts and as these contracts expire over the next 10 to 15 years, prices will increase significantly. Natural gas prices in Fairbanks are projected by netting back or deducting transmission costs from the projected "lower 48" market.

Fuel prices are established in a variety of ways, depending upon the fuel type and market prospects. For some fuels a current price is established, either through market conditions or by contract. These fuels are coal from the Healy Mine in Fairbanks, Cook Inlet natural gas and refined oil products. Other fuels are identified for development primarily for export markets and their prices are netted back to the Alaska market by subtracting the appropriate transportation costs; these are North Slope natural gas to Fairbanks, coal from the Beluga field in the Cook Inlet region, and natural gas liquids and methanol. Two other fuels, peat and refuse-derived fuel, have their prices developed from the best estimate of production costs.

Fuel escalation is examined from a slightly different perspective. The oil, natural gas and natural gas liquids escalate, more or less, in unison because of their transportability and substitutability. Coal price escalation is tied more closely to production costs, although at some point oil price escalation becomes important. The escalation rate of peat and refuse fuels is tied closely to production costs.

This report devotes a chapter to each of the fuels analyzed. Each chapter has been assembled from a corresponding working paper. As few changes as possible were made in changing the working papers into chapters. Changes that were made were done so on the basis of additional information gained since the initial completion of the working paper. These changes resulted in a slight price increase for coal and Cook Inlet natural gas and a price decrease for peat and refuse-derived fuel. Those readers interested in the draft working papers are referred to them as follows:

1.1 - Cook Inlet Natural Gas: Future Availability and Price Forecasts
1.2 - Alaska Coal Future Availability and Price Forecasts
1.3 - Peat Availability and Price Forecasts
1.4 - Municipal Refuse-Derived Fuel (RDF)
1.5 - North Slope Natural Gas Availability and Price Forecasts
1.6 - Natural Gas Liquids/Methanol Availability
1.7 - Fuel Oil Availability and Price Forecasts

2.0 COOK INLET NATURAL GAS: AVAILABILITY AND PRICE FORECASTS

In the 1950s and 1960s oil companies in search of crude oil, a readily transportable commodity, encountered (to their probable distress) more natural gas than oil. Since gas is not as easily transported to markets as oil, a buyer's market occurred. As a result, the natural gas utility system was created and such industries as the Collier Carbon and Chemical Company and the Phillips/Marathon LNG export plant were attracted. Alaskan consumers in the Cook Inlet region benefited greatly from their buyer's market position and even today enjoy the lowest cost natural gas in the United States. As a logical consequence, the region depends heavily on natural gas as a major source of energy for electric power generation, home and commercial space heating, and appliances--in fact, for most energy except for transportation fuels.

It is unlikely that these conditions will continue much further into the future, and significant shifts may occur in end use of energy and, hence, in electric power generation costs as well as requirements. This chapter examines the relationship between natural gas availability and prices in the Cook Inlet region in conjunction with demand projected on an annual basis. It should be noted that peak day gas supply limitations and the consequences are not addressed.

An ideal objective would be to provide a supply curve (price versus cumulative quality consumed). Unfortunately, as geologic data on yet-to-be-discovered resources are not available, this study used existing reserve information and long-term and probable future gas sales contract conditions. As a consequence, a conservative forecasting stance is taken.

1. The possibility of significant new reserve disclosures and developments is excluded and not credited as being available.

2. The most recent (and substantially lower than previous) estimates of identified economically recoverable reserves published by the Alaska Oil and Gas Conservation Commission are used vis-a-vis the generally more optimistic reserve estimates prepared in the early 1970s by the U.S. Bureau of Mines.

Once a reasonable estimate of remaining recoverable reserves is developed, several scenarios of the likely depletion of these reserves are provided. The intent is to identify likely dates (years) when gas deliverability and prices might significantly change. These scenarios are based on recent estimates of both natural gas utility sales and electrical power production from natural gas. It is recognized that different natural gas utilization scenarios could result in different estimates; however, it is not expected that the end conclusions would be substantially changed.

2.1 NEAR-TERM AVAILABILITY OF NATURAL GAS

The future availability of Cook Inlet natural gas for in-state consumption is clearly dependent on: 1) the quantity of known remaining recoverable reserves; 2) the level of commitment of those reserves to in-state consumption; 3) the likelihood that uncommitted reserves might become available for dedication to in-state uses; 4) the possibility that certain reserves now committed to the Pacific Alaska LNG (PALNG) project might be released for in-state consumption; 5) the expected rate of consumption; and finally, 6) the likelihood that new reserves will be identified and committed for in-state consumption.

This section develops a number of natural gas availability scenarios that appear logically supportable. Although most (67% in 1979) of the natural gas sold in Cook Inlet is exported as LNG (to Tokyo Gas and Tokyo Electric) or converted to ammonia and urea for export to Pacific Rim markets, the major concern of this study is the gas available for in-state consumption either directly by gas utility customers or by the electric utilities. Some gas is also used in oil and gas production operations so is not available to the utilities. Outlets to other markets, however, do have an influence on future actions by lease holders with as yet uncommitted reserves.

The base year chosen for this portion of the study is 1979 for consumption and 1980 for reserve base. These are the latest years for which complete data were available at the time this section of the report was initially completed. In those instances (e.g., ammonia/urea production) where preliminary 1980 data indicate that higher throughputs can be accommodated, the 1979 data were adjusted for purposes of forecasting future consumption. It is recognized that 1979 was not necessarily a representative "weather year," because temperatures in the Cook Inlet region since 1976 have been warmer than the historical average. As a consequence, the scenarios developed may underestimate future actual consumption.

2.1.1 Recoverable Reserves and Reserve Commitment Base

The estimated remaining recoverable reserves in the Cook Inlet region are shown in Table 2.1. These are based on information supplied by the Alaska Oil and Gas Conservation Commission (AOGCC).[a] Commitments of these reserves are estimated and shown in Table 2.2. These are based on our review of all major contracts for gas sales and adjusted for drawdown prior to January 1, 1980, using data provided by AOGCC[b] and data obtained by the Institute of Social and Economic Research[c] from detailed records in AOGCC files. Appendix A provides detail on a field-by-field basis.

The committed status of known recoverable reserves for Cook Inlet natural gas as of January 1, 1980, can be summarized as follows:

	Billions of Cubic Feet (Bcf)
Committed Resources	
Alaska Gas and Service Company	375
Chugach Electric Association	310
Anchorage Mun. Light and Power[d]	?
Total for In-State Consumption (other than oil and gas production activities)	685
Pacific Alaska LNG Associates[e]	829+
Export (LNG + NH_3/Urea)	730
Total	2244+
Uncommitted Reserves	1839

(a) Alaska Oil and Gas Conservation Commission, Bulletin, July 1980 and letter, Hoyle W. Hamilton to W. H. Swift, November 14, 1980.
(b) Letter, Hoyle W. Hamilton, AOGCC, to W. H. Swift, January 12, 1981.
(c) Letter, O. S. Goldsmith to W. H. Swift, January 13, 1981.
(d) Royalty gas. Commitment status uncertain due to recent transfer of State land to the Cook Inlet Region Incorporated.
(e) Based on DeGolyer and MacNaughten estimate filed with the FPC. If AOGCC reserve estimates are used, this value is 740+. Values do not include the Tyonek Field for which no reserve estimate is available.

TABLE 2.1. Cook Inlet Natural Gas Status and Contracts - 1980

	Recoverable Reserves 1/1/80 Bcf(4)	Alaska Pipeline Co.	Chugach Electric Assoc.	AMP&L	City of Kenai	Collier Carbon and Chemical	Lease Use	Pacific Alaska LNG Assoc.	Tokyo Gas, Tokyo Electric	Peninsula Greenhouses, Inc.	SOCAL ARCO Rental	Shut In 1/1/80	State Royalty %	Net Production(4) 1979 Bcf	Net Production(4) Cumulative to 1/1/80 Bcf
Beaver Creek	240	--	--	--	--	--	X	(5)	--	--	--	--	0	0.00925	0.463
Beluga River	747	--	X	--	--	--	X	X	--	--	--	--	7.99	16.99	90.46
Birch Hill	11	--	--	--	--	--	--	--	--	--	--	X	0	0	0.1
Cannery Loop(3)	N.A.	--	--	--	--	--	--	--	--	--	--	X	N.A.	N.A.	N.A.
Falls Creek	13	--	--	--	--	--	--	--	--	--	--	X	0	0	<0.1
Ivan River	26	--	--	--	--	--	--	X	--	--	--	X	0	0	0
Kaldachabuna	N.A.	--	--	--	--	--	--	--	--	--	--	--	N.A.	N.A.	N.A.
Kenai	1313	X	--	Royalty	X	X	X	--	X	--	X	--	~3.09	97.0	995.1
Lewis River	90	--	--	--	--	--	--	X	--	--	--	X	0	0	0
McArthur River	78	--	--	--	--	X	X	(5)	--	--	--	--	12.5	16.61	66.90
Nicolai Creek	17	--	--	--	--	--	--	--	--	--	--	X	12.5	0	1.06
North Cook Inlet	1074	Royalty Only	--	--	--	--	X	--	--	--	--	--	12.5	49.4	456.5
North Fork	12	--	--	--	--	--	--	--	--	--	--	X	0	0	0.1
N. Middle Ground	N.A.	--	--	--	--	--	X	--	--	--	--	X	12.5	0	N.A.
Sterling	23	--	--	--	--	--	X	--	--	X	--	--	2.722	0.0254	1.961
Stump Lake(3)	N.A.	--	--	--	--	--	--	--	--	--	--	--	N.A.	N.A.	N.A.
Swanson River	242(2)	--	--	--	--	--	X	--	--	--	--	--	0	(120.3)(6)	(1,173.7)(6)
Trail Ridge(3)	N.A.	--	--	--	--	--	--	--	--	--	--	--	N.A.	N.A.	N.A.
Tyonek(1)	N.A.	--	--	--	--	--	--	X	--	--	--	X	0	N.A.	N.A.
West Foreland	N.A.	--	--	--	--	--	--	--	--	--	--	--	--	--	--
West Fork	7	X	--	--	--	--	X	--	--	--	--	--	0	0.7705	0.8220

Notes

1. Represents combined total of fields. Also identified as Albert Kaloa and Moquaki.
2. Being injected for pressure. Maintenance with Rental Gas from the Kenai field. Original indigenous reserves estimated at 59.6 Bcf. Anticipated recovery of injected gas estimated at 192 Bcf for total of 242 Bcf after commencement of blowdown.
3. Potential discovery or being drilled.
4. Alaska Oil and Gas Conservation Commission.
5. Contracts reportedly being negotiated.
6. Represents injection.

TABLE 2.2. Estimated Cook Inlet Natural Gas Reserve Commitment Status as of January 1, 1980, Bcf

	Recoverable Reserves(6)	Alaska Pipeline Co.	Chugach Electric Assoc.	AMP&L	Collier Carbon & Chemical	Pacific Alaska LNG Assoc.	Tokyo Gas Tokyo Electric	SOCAL, ARCO Rental	Uncommitted Reserves
Beaver Creek	240	--	--	--	--	--	--	--	240
Beluga River	767	--	310	--	--	~624	--	--	Negative
Birch Hill	11	--	--	--	--	--	--	--	11
Cannery Loop	N.A.	--	--	--	--	(1)	--	--	N.A.
Falls Creek	13	--	--	--	--	--	--	--	13
Ivan River	26	--	--	--	--	106(4)	--	--	0
Kaldachabuna	N.A.	--	--	--	--	--	--	--	N.A.
Kenai	1313	338	--	(2)	499	--	--	106	370
Lewis River	90	--	--	--	--	99(4)	--	--	0
McArthur River	78	--	--	--	--	--	--	--	78
Nicolai Creek	17	--	--	--	--	--	--	--	17
North Cook Inlet	1074	30(7)	--	--	--	--	231(5)	--	813
North Fork	12	--	--	--	--	--	--	--	12
N. Middle Ground	N.A.	--	--	--	--	--	--	--	N.A.
Sterling	23	--	--	--	--	--	--	--	23
Stump Lake	N.A.	--	--	--	--	(1)	--	--	N.A.
Swanson River	242(3)	--	--	--	--	--	--	--	242
Trail Ridge	N.A.	--	--	--	--	--	--	--	N.A.
Tyonek	N.A.	--	--	--	--	All	--	--	0
West Foreland	20	--	--	--	--	--	--	--	20
West Fork	7	7	--	--	--	--	--	--	0
	Total committed reserves = 2350+								
Total	3933	375	310	--	499	829+	231	106	1839

Notes

1. Participant in exploration under way in 1980.
2. Uncertain royalty status.
3. Battelle estimate of gas available on blowdown.
4. Based on DeGolyer and MacNaughten reserve estimate in 1975.
5. This figure assumes that T.G. and T.E. contracts will be met by gas from the Cook Inlet Field. In actuality, a significant portion is supplied by the Kenai Field.
6. Alaska Oil and Gas Conservation Commission.
7. Royalty.

2.1.2 Potential for Release of Uncommitted Reserves

The potential for release (and commitment to contracts for in-state consumption) can be addressed on a field-by-field basis taking into account lease ownership, alternative commitment opportunities, field size and location, availability of gas transmission pipelines, and future producibility.

Currently Producing Fields (1261 Bcf)

Of the currently producing fields, the uncommitted reserves are:

North Cook Inlet	813 Bcf
Kenai	370
McArthur River	78
	1261 Bcf

The North Cook Inlet Field leases to Phillips and Marathon, among others, and is the principal supplier to the Tokyo Electric and Tokyo Gas contracts for LNG. This is a very profitable contract for the lessees as the price appears (see Appendix A) directly related to world oil prices and is free of Federal price regulation. Although the existing contract expires in 1984, there is an option to renew. We believe that this option will be taken up and reserves will not be released for in-state consumption. Contract extension will be under the jurisdiction of the Economic Regulatory Administration, U.S. Department of Energy (DOE). In addition, production from the North Cook Inlet Field is expected to decline at a rate of about 10% per year beginning in 1985.

The Kenai Field is leased largely by Union and Marathon and is the second supplier (~30%) to the Phillips/Marathon LNG plant serving the Tokyo contracts. The Kenai Field also provides the bulk of the feed stock to the Collier Carbon and Chemical Company's ammonia/urea plant. Collier Carbon and Chemical is a wholly owned subsidiary of Union Oil Company. Due to the profitability of both the Phillips/Marathon and the Collier Carbon arrangements, we expect that the remaining reserves will be retained for future commitment to these operations.

The McArthur River Field (primarily an oil field) lease is owned principally by Union Oil Company and is a supply source for Collier Carbon and

Chemical Company. Gas production started to decline at about 8% per year in 1971. For this reason and those already cited, we do not expect McArthur River gas to enter the in-state consumption market.

The above reasoning suggests that the 1261 Bcf of uncommitted reserves in producing fields (except Beluga River) should be deducted from the 1839 Bcf of total uncommitted reserves, leaving 578 Bcf that might become available to PALNG Associated.

The Pacific Alaska LNG (PALNG) currently has more than 829 Bcf in reserve commitments.[a] These reserves are all under contracts that contain "kick-out" provisions. If PALNG does not take delivery of gas or meet other conditions specified in the contract prior to the "kick-out" date, the commitments may be cancelled. It is our understanding that these dates have been passed but that none of the suppliers have as yet exercised this option.[b]

The likelihood that the PALNG project will go forward is clouded:

1. Pacific Gas and Electric Company, a major sponsor, has limited its support for the projects.[c]
2. Natural gas requirements in California are declining or at least not increasing as rapidly as previously expected.
3. Alternative gas supplies to the California market are gaining strength.
4. PALNG has not yet been able to establish the reserve commitments necessary to satisfy Federal Energy Regulatory Commission (FERC) licensing requirements.
5. Regulatory (FERC) proceedings regarding the LNG terminal at Point Conception, California, are not scheduled to be completed until at least mid-to-late 1982. At issue is the seismic safety of the site.

(a) As of July 1982 these commitments have increased to about 980 Bcf. Oil and Journal, July 26, 1982, p. 106.
(b) Letter, Len McLean, Pacific Alaska LNG Associates, to W. H. Swift, January 5, 1981.
(c) Another sponsor is needed to cover one-fourth to one-third of the projects costs. Oil and Gas Journal, July 26, 1982, p. 106.

Reserves committed to PALNG are as follows:

Beluga River Field[(a)]	~624 Bcf
Ivan River[(b)]	106
Lewis River[(c)]	99
Tyonek[(d)]	all
	829+ Bcf

Of the above fields, only the Beluga River Field is producing (supply to Chugach Electric Association, CEA) but it is remote from existing pipelines. Gas from both the Ivan River, Lewis River and Tyonek Fields is not committed nor are these fields connected to a pipeline. The Ivan River and Lewis River Fields are located near the Beluga River Field so do not have ready pipeline access; the Tyonek Field is reasonably close to pipeline access. None of the lessees of these fields appear to have direct or indirect connection to out-of-state gas sales except via PALNG.

In the author's opinion, there is a better-than-even chance that the reserves now committed to PALNG will be released, likely to the highest bidder, and potentially will be available for in-state use.

Other Known Reserves--Not Producing or Committed (578 Bcf)

The remaining estimated reserves of natural gas in the Cook Inlet region may be classified both by size and remoteness. These fields are as follows in likely order of interest.

- Beaver Creek (240 Bcf): Not connected by pipelines but centrally located in the Kenai Peninsula. Union/Marathon are the lessees. This field appears to be the most attractive for next development.

(a) Based on contract terms for reserve commitments from Chevron USA and Atlanta Richfield coupled with assumption that Shell Oil Company's unstated commitments are comparable to those of the other lessees.
(b) Based on DeGolyer and MacNaughten estimates. The Alaska Oil and Gas Conservation Commission carries a value of 26 Bcf.
(c) Contract commitment is for 99 Bcf; the AOGCC estimates 90 Bcf.
(d) No reserve estimates are available.

- Nicolai Creek (17 Bcf): Not connected but a pipeline runs through the field. Texaco is the lessee.
- Birch Hill (11 Bcf): Not connected but pipeline to Nikiski is nearby. Lessees are Chevron/Arco.
- Sterling (23 Bcf): Not connected but Alaska Pipeline is adjacent. Lessees are Union and Marathon.
- West Foreland (20 Bcf): Not connected but reasonably near Trading Bay production facilities. AMOCO is the operator.
- Swanson River (242 Bcf): Reserve estimates are debatable. Although included in this listing, rental gas is committed for return to Kenai Field producer and, if produced, will probably be devoted to ammonia/urea production or LNG export to Tokyo Electric and Tokyo Gas.
- Falls Creek (13 Bcf): Not connected and very remote. Chevron USA is lessee.
- North Fork (12 Bcf): Not connected and very remote. Chevron USA is lessee.

Depending on whether the reserves committed to PALNG Associates will be released and committed to in-state contracts, the above data can be summarized as shown in Table 2.3.

TABLE 2.3. Cumulative Natural Gas Reserves Potentially Available for In-State Use--Bcf, January 1, 1980

	PALNG Reserves Released	PALNG Project Proceeds
Committed Reserves	685	685
PALNG Reserves	1514+	685
Beaver Creek	1754+	925
Small/Near Fields	1805+	976
Small/Remote Fields	1825+	996
Small/Very Remote Fields	1850+	1021

Implication of The Natural Gas Policy Act of 1978

The price of natural gas is controlled either by long-term contracts with purchasers or, if uncommitted under contract, by the Natural Gas Policy Act of 1978 (NGPA). Although no applications for price determination under the NGPA have been made for Cook Inlet natural gas, it appears the uncommitted reserves will fall under Section 109(a)(3) of the NGPA. This sets the maximum lawful price at $1.45/MMBtu for April 1977 with a quarterly inflation adjustment factor determined by the GNP deflator, plus a 2.43% per year escalator. For January 1980, the adjusted maximum lawful price was $1.786/MMBtu. Assuming the NGPA remains in full effect, it appears that producers committing additional reserves for intrastate consumption will seek a price as high as they can obtain up to that ceiling. If the NGPA is repealed or modified to effectively decontrol Cook Inlet natural gas, the producers may obtain a higher price equivalent to the best alternative, i.e., an "opportunity price."

At the present time the only gas that appears to be effectively deregulated is the gas dedicated by Phillips/Marathon to the Tokyo Electric and Tokyo Gas Companies. This gas had an effective wellhead price of $2.07/Mcf in December 1980 and, based on monthly price behavior during 1980, appears now to be reaching and tracking very closely world crude oil prices at the Japan point of delivery. Presumably, the opportunity price for gas owned by both Phillips and Marathon will track this situation.

In the case of Union Oil Company leases, the producer's opportunity price (for gas not sold to Tokyo Electric or Tokyo Gas) is difficult to determine since their principal interest would probably be to maintain operation of the Collier Carbon and Chemical Company ammonia/urea operation. The latter is a wholly owned subsidiary of the Union Oil Company and, in effect, the price is a transfer price that most likely would be a net-back from that received in sales of the ammonia/urea products in the Pacific Rim markets. In this instance, they compete with products produced from gas at either the world price or at a somewhat lower average domestic price, but certainly not as low as the current cost of gas to Collier Carbon and Chemical Company's Kenai Plant ($0.61/Mcf marginal cost).

Understandably, all producers will be reluctant to commit reserves until the question of the PALNG Associates project and the issue of natural gas deregulation are resolved. The observation includes those producers without direct access to LNG or ammonia/urea markets.

2.1.3 Natural Gas Utilization Scenarios

This section addresses the future drawdown of dedicated reserves and potential reserves that might be committed to in-state use.

Figure 2.1 illustrates the natural gas flows from producing fields to major consumers for 1979, the latest year for which complete data are available.[a] Of greatest interest to this study are the gas flows shown in the upper right hand corner of the figure because these are major in-state consumers, i.e., CEA, gas utility sales to end-use consumers, to the military installations and to Anchorage Municipal Power and Light (AMP&L) for electrical energy generation. Our scenarios regarding these consumers rest on the following assumptions:

1. Sales to Cook Inlet military installations will remain constant at about 5 Bcf/year.

2. Sales of natural gas for direct consumer use will increase at about 4% per year from the 1979 base year (Goldsmith and O'Connor 1980).

3. Sales of natural gas from a Beluga Field to CEA will increase at a rate equal to the most recent medium growth forecast for Cook Inlet area electricity sales as follows (Goldsmith and Huskey 1980).

1980 - 1985	5.04% per year
1985 - 1990	2.67% per year
1990 - 1995	5.08% per year

(a) Some of the data used in preparation of Figure 2.1 were drawn from the report "Historic and Projected Oil and Gas Consumption" dated January 1980 and prepared for the Royalty Oil and Gas Development Advisory Board and the 11th Alaska State Legislature. It is understood that revisions to this report are being made. Gas sales by Alaska Gas and Service Company (AGAS) to CEA and AMP&L are from telephone discussion with Bill Hickman of AGAS January 23, 1981.

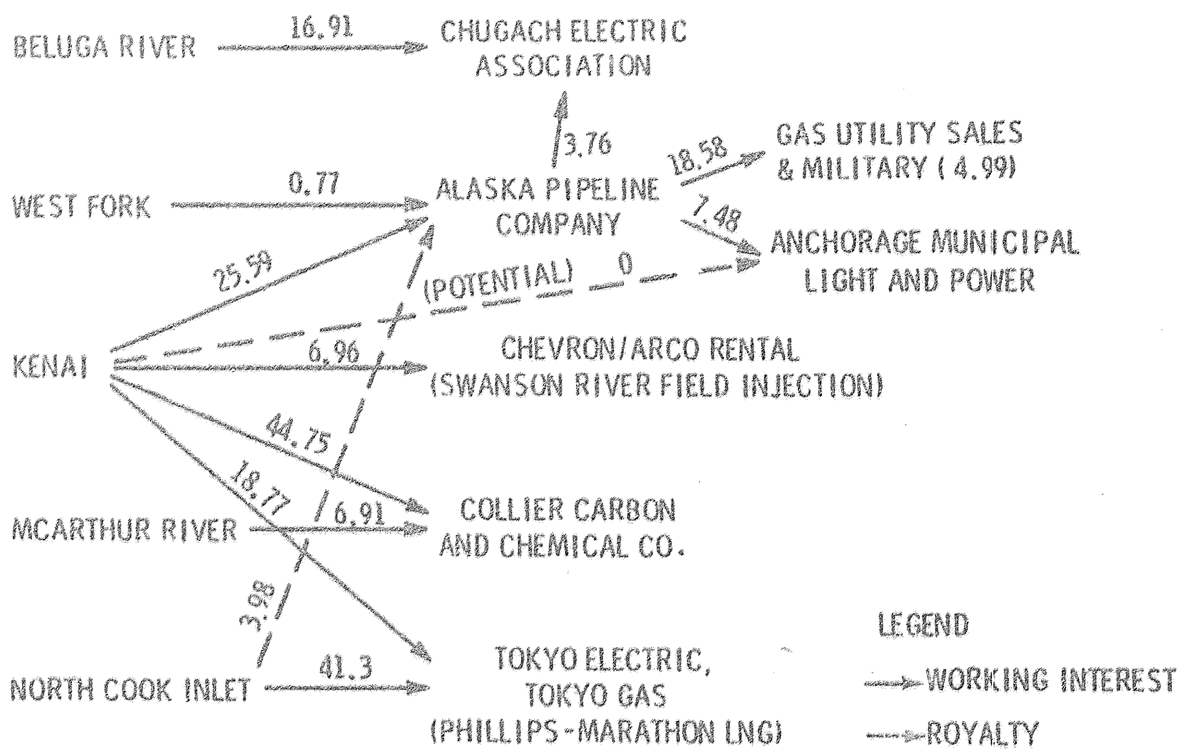

FIGURE 2.1. Principal Natural Gas Sales for Cook Inlet Region in 1979, Bcf

Total gas sales from the Beluga River Field under the existing contract, however, have an upper limit of 21.9 Bcf/year under the maximum "take" provision of the gas sales contracts to CEA. If CEA desires additional take above 21.9 Bcf/year, it seems likely that a separate contract would be negotiated (at a higher price).

4. If the Anchorage-Fairbanks electrical power interconnection is installed in 1984, gas sales will increase by the following amounts ("Intertie Gas"):[a]

Bcf/year	Bcf/year
1984 - 2.48	1989 - 3.36
1985 - 2.98	1990 - 3.24
1986 - 3.07	1991 - 3.10
1987 - 3.27	1992 - 3.03
1988 - 3.32	1993 - 2.79

(a) Based on estimated incremental generation of electrical energy and converting estimated GWh/year using a heat rate of 12,000 Btu/kWh and a heating value of 1,035 MMBtu/Mcf. GWh figures provided by Dave Shafer, Commonwealth Associates, January 26, 1981.

5. Sales of natural gas by AGAS to AMP&L and to CEA will increase at a rate of 90% of that shown in Assumption 3, reflecting improvements in plant heat rates.

   It seems unlikely that CEA would reopen its present contract (that otherwise runs to 1997) with the Beluga Field producers and expose itself to the potential for much higher prices (certainly as high as Chugach would have to pay AGAS for gas from that source, and possibly much higher). The last case could apply if the Beluga producers were, for example, to sell gas to Phillips/Marathon (a pipeline connection would be required to the North Cook Inlet Field Platform).

   If, as seems likely, Chugach does not choose to exceed its Beluga maximum take provision, then the equivalent generation would be shifted to gas supplied by AGAS to AMP&L or Chugach.

   Alternatively, Chugach could seek a separate contract for supplemental Beluga gas over and above the maximum take provision. To the extent they are not bound by the commitments in the contract with PALNG, the producers presumably would be willing to provide such gas and at a price that recognizes the cost to Chugach of gas from AGAS. This latter price would set a floor under the supplemental Beluga gas price.

6. Generation capacity additions at least until 1988 are confined to natural gas- (or oil-)fired combustion turbine and combined cycle units. In 1988 the Bradley Lake hydroelectric project comes on-line displacing about 3.3 Bcf/year of natural gas electric utility fuel. Anticipating Susitna hydroelectric or other state-financed baseload projects, the utilities will avoid capital-intensive plant additions and opt for higher fuel cost alternatives in an attempt to minimize additions to their rate base that may later become idle. Exemptions from the provisions of the Power Plant and Industrial Fuels Use Act may be necessary in the future; we believe that strong cases may be made for such exemptions.

Based on these assumptions, two primary scenarios for natural gas utilization are developed. Table 2.4 summarizes the consequences of these two scenarios and runs them to the year 2000; after 1993 the scenarios are on a best-guess basis for illustration only.

1. Business As Usual: No regulatory or contractual impediments occur. Cook Inlet gas consumers, both electrical utilities and end-use consumers, continue dependence on natural gas.

2. Constrained: Contractual impediments (Chugach with Beluga Field producers) shift future gas demands to AGAS, and "future gas," i.e., that might occur after 1985, is provided by AGAS either to AMP&L or CEA. In addition, gas consumed to service the interconnection between Cook Inlet and Fairbanks is provided by AGAS.

It is recognized that the assumptions used at this stage do not optimize loadings of the various generation plants in a systems sense. Nevertheless, for purposes of analyzing gas availability, they seem reasonable and lead to the following conclusions:

Business as Usual Scenario

1. Gas sales to CEA reach the maximum delivery or take rate of 21.9 Bcf/year in 1985.

2. Cumulative AGAS sales to gas utility customers and the electric utilities exhaust the currently dedicated reserves in 1990, and alternative gas at a higher price must be supplied.

3. Beluga gas sales (unimpeded by maximum take contract provisions) result in expenditures of committed reserves in 1993.

4. All gas currently committed for in-state use is expended in 1991.

Constrained Case

1. Alaska Gas & Service Company dedicated reserves are exhausted in 1989.

2. Beluga gas reserves dedicated to CEA become exhausted in 1995.

TABLE 2.4. Cook Inlet Natural Gas Utilization Scenarios, Bcf/Year or Bcf Cumulative

	Business as Usual - No Impediments							Constrainted Case — Beluga Field Ceiling at Maximum Take "Intertie Gas" Supplied by AGAS					
Year	Military	Gas Utility Sales	AG&S Sales to Electric Utility	Cumulative AG&S Sales	Beluga to Chugach	Cumulative Beluga Sales	Cumulative AG&S Plus Beluga Sales	"Intertie" Gas	Cumulative "Intertie" Gas	Chugach Gas Demand Shift to AG&S	Cumulative Increase in AG&S Sales to Electric Utility	Revised Cumulative AG&S Sales	Revised Cumulative Beluga Sales
1980	5.00	14.60	11.75	31.35	17.76	17.76	49.11					31.35	17.76
81		15.19	12.28	63.82	18.66	36.42	100.24					63.82	36.42
82		15.79	12.84	97.45	19.60	56.02	153.47					97.45	56.02
83		16.42	13.42	132.29	20.57	76.61	208.90					132.29	76.61
84		17.08	14.03	168.40	5.05%/yr 21.63	98.24	266.64	2.48	2.48		2.48	170.88	[illegible]
85		17.77	4.54%/yr 14.27	205.84	22.31 (d)	120.55	326.39	2.98	5.46	0.41	5.87	211.71	120.14
86		18.48	15.02	244.34	22.91	143.46	387.80	3.07	8.53	1.01	9.95	254.29	142.04
87		19.21	15.38	283.93	23.52	166.98	450.91	3.27	11.80	1.62	14.84	298.77	163.94
88		19.98	12.45	321.36	2.67%/yr 24.15	191.13	512.49	3.32	15.12	2.25	20.41	341.77	185.84
89		20.78	2.40%/yr 12.83	359.[illegible]	24.79	215.92	575.88	3.36	18.48	2.89	26.66	386.63 (e)	207.74
1990		21.61	13.22	399.80 (a)	25.45	241.37	641.17	3.24	21.72	3.55	33.45	433.25	229.64
91		22.48	13.97	441.25	26.74	268.11	709.36 (c)	3.1[illegible]	24.82	4.84	41.39	483.63	251.54
92		23.38	14.76	484.39	28.10	396.21	780.60	3.0[illegible]	27.85	6.20	50.62	534.01	273.44
93		4%/year 24.31	15.59	529.29	5.88%/yr 29.53	325.74 (b)	855.03	2.79	30.64	7.63	61.04	590.33	295.34
94		25.29	4.57%/yr 16.45	576.03	31.03	356.71	932.74						317.24
95		26.30	17.36	624.69	32.61	389.38	1014.07						339.14 (f)
96		27.35	18.20	675.24	34.09	423.47	1098.71						361.04
97		28.44	19.08	727.76	35.65	459.12	1186.88						382.94
98		29.58	4.1%/yr 20.00	782.34	4.56%/yr 37.27	496.39	1278.73						404.84
99		30.76	20.96	839.06	38.97	535.36	1374.42						426.74
2000		31.99	21.95	898.00	40.75	576.11	1474.11						448.64

(a) Gas reserves currently dedicated to Alaska Gas and Service Co. exhausted in 1990.
(b) Beluga Field gas dedicated to Chugach Electric Association exhausted in 1993.
(c) Total gas currently dedicated to in-state use exhausted in 1991.
(d) Chugach Electric Association Contract with Beluga Field producers has maximum take provision of 21.9 Bcf/year. The greater take presumes Chugach would be willing to renegotiate or enter a new contract.
(e) If Alaska Gas and Service Co. sales to electric utilities assume demand shed from Beluga Field as a result of Chugach maximum take provision and also pick up "Intertie Gas" demand, AGAS dedicated reserves are exhausted by 1989.
(f) Beluga Gas Reserves dedicated to Chugach Electric Association are exhausted in 1995.

The dates mentioned in these conclusions are not intended to indicate that "all the gas is gone," only that extreme changes in gas prices are likely to occur as these dates approach and are passed. These price changes may occur gradually as new gas purchases are rolled in (e.g., supplies to AGAS) or abruptly (e.g., CEA from the Beluga Field). We also recognize that CEA is engaged in exploratory drilling for gas and may find economically recoverable reserves that could displace or supplement existing committed reserves. Future natural gas prices are the subject of the next section.

2.2 FORECASTING NEAR-TERM NATURAL GAS PRICE

Natural gas prices were mentioned in the preceding section only to the extent of noting that major price discontinuities are expected in the future and noting the possible consequences of these discontinuities on future seller/purchaser transactions. As in the analysis of gas availability, this analysis leans heavily on review of existing long-term contracts and the likely (largely economic) motivations of both the producers and purchasers of natural gas after these contracts expire.

This section attempts to develop reasonable scenarios for future natural gas prices that would be paid either by the electrical utilities or by end-use consumers. To the extent possible an effort is made to produce a schedule of the likely gas price over time. The scenario approach is used because a number of uncertainties now exist that could markedly affect prices.

2.2.1 Factors in Price Formation for Indigenous Cook Inlet Natural Gas

The prices or costs of natural gas seen by the purchasing electrical utilities or the end-use consumers are dependent on a number of factors, some of which are reasonably predictable and some of which are not. These factors are presented in estimated order of importance.

1. Provisions in existing long-term contracts including:

    a) Predictable price increase scheduled in advance.

    b) Provisions that become operational if producers of a given field make deliveries from that field to a third party under contracts with different price conditions.

c) Provisions that link prices of future sales in the Cook Inlet area to those in other fields.

d) Provisions that are linked to some measure of inflation.

e) Expiration dates and provisions for options to extend.

f) Contract provisions that establish a maximum take for a given year. If the purchaser wishes to increase his take above that maximum, he may expose himself to having to renegotiate less favorable terms.

g) Minimum take (take or pay) provisions. The purchaser pays for gas not taken and the effective gas cost is thus higher if he does not achieve the minimum take.

h) Special provisions for compression, gathering and wheeling.

2. Whether the market conditions can be classified as a "seller's" or "buyer's" market. In the initial years of Cook Inlet natural gas production, the amount of gas available far exceeded demand, resulting in a "buyer's" market. Thus prices were depressed. As long as the PALNG proposed plant remains pending and willing to purchase gas at the maximum lawful price under the NGPA of 1978 (or at possibly a higher price if deregulation occurs), the market is a "seller's" market. If the PALNG project is cancelled and another major market outlet does not develop, the market will revert to "buyer" conditions. The uncertainty regarding PALNG obviously clouds the understanding of future prices.

3. Potential deregulation of natural gas or substantial revision to the Natural Gas Policy Act of 1978 (NGPA). This would seem to be in concert with the current federal administration's economic policies. However, the political difficulties in implementing such a change are great. The maximum lawful price for "new" (Section 103) gas under NGPA was $2.158/MMBtu in January 1980 and escalates at 2.43% per year in real terms.

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   a) Predictable price increase scheduled in advance.

   b) Provisions that become operational if producers of a given field make deliveries from that field to a third party under contracts with different price conditions.

c) Provisions that link prices of future sales in the Cook Inlet area to those in other fields.

d) Provisions that are linked to some measure of inflation.

e) Expiration dates and provisions for options to extend.

f) Contract provisions that establish a maximum take for a given year. If the purchaser wishes to increase his take above that maximum, he may expose himself to having to renegotiate less favorable terms.

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4. To the extent not constrained by price regulations, the opportunity price the seller might be able to obtain in a sale to a third party; a related case would be the transfer price to a wholly owned subsidiary, e.g., the Union Oil Company/Collier Carbon and Chemical Company relationship. In this instance the sale might not be fully at "arms length." Similarly, the sellers' perception of the buyers' opportunity cost of natural gas from another source, and quite conceivably, the cost of a replacement distillate combustion turbine fuel, would be a factor.

5. License extension for existing natural gas facilities. The Phillips/Marathon LNG export facility and sales contracts were licensed by the old Federal Power Commission. The present contract expires June 1, 1984, and contains an option to renew for an additional 5 years, but without a specification of price. In order to renew, approval of the export contract extension must be obtained from DOE's Economic Regulatory Administration. From the standpoint of Alaskan consumers, regulatory action here presumably would only affect the price of royalty gas taken by AGAS if the latter's contract with the state were to be similarly extended.

6. Amount of state production (severance) tax, which is currently the greater of 10% of first sale price or 6.4¢/Mcf. In the case of wells nearing exhaustion, this tax may be adjusted downward by a variable economic limit factor designed to maximize economic recovery.

Table 2.5 summarizes the first sale price conditions for existing natural gas contracts. These prices do not include the state production (severance) taxes, which are applicable to working interest but not to royalty gas.

2.2.2 Interaction Between Natural Gas Contract Price Terms and Likely Future Events

Adjustments in gas prices are based upon events that may reasonably take place in the future. Based on the contract terms and the scenarios developed above, we estimated key dates of expected significant events for Cook Inlet

TABLE 2.5. Summary of First Sale Natural Gas Contract Price Conditions

Field	Alaska Pipeline Co.	Chugach Electric	Anchorage Municipal	Collier Carbon & Chemical	Pacific Alaska LNG Assoc.	Tokyo Gas Tokyo Electric	Peninsula Greenhouses	SOCAL/ARCO Rental
Beluga River	--	Wellhead Price/Mcf \$0.1962 1980 0.1962 1981 0.2003 1982 0.2062 1983 0.2103 1984 0.2103 1985 0.2145 1986 0.2145 1987 If Pac. Alaska LNG sales initiated, prices would be: \$0.8478 1985 0.8645 1986 0.9122 1987	--	--	Wellhead \$1.60/Mcf as of 1/01/81, increases \$0.01/Mcf per quarter	--	--	--
Ivan River	--	--	--	--	Same as for Beluga Field. If deregulated, escalate by producer price index.	--	--	--
Kenai	Wellhead \$0.27/Mcf 1/1/80 - 12/31/85 from 1/1/86 - 12/31/92, the greater of \$0.27/Mcf or the average price Union/Marathon will receive from new third party sales. To above, add deliverability charge of \$0.29/Mcf escalating with producer price index (all goods).	--	Royalty gas price and volume in dispute.	Wellhead price \$0.61/Mcf (1/1/80) to be renegotiated by 1/1/81.	--	Not available	--	Wellhead price \$0.081 to \$0.089/Mcf depending on delivery pressure \$0.16/Mcf used for royalty calculations.

TABLE 2.5. (contd)

Field	Alaska Pipeline Co.	Chugach Electric	Anchorage Municipal	Collier Carbon & Chemical	Pacific Alaska LNG Assoc.	Tokyo Gas Tokyo Electric	Peninsula Greenhouses	SOCAL/ARCO Rental
Lewis River	--	--	--	--	Same as Beluga Field. If deregulated then average of 3 highest prices paid in Cook Inlet by pipeline companies for resale.	--	--	--
McArthur River	--	--	--	Not Available	--	--	--	--
North Cook	Royalty gas. Wellhead price same as paid by Tokyo Gas & Electric plus $0.12/Mcf (1/1/81); gathering charge to increase 6%/ plus $0.10 compression charge to increase 6%/ year.	--	--	--	--	Wellhead price $2.0649/MMBtu in 12/80. Future price appears linked to world oil price.		
Sterling	--	--	--	--	--	--	$0.40/Mcf	--
Tyonek	--	--	--	--	Same as for Lewis River Field.	--	--	--
West Fork	Not available but believed to be similar to Kenai Field.	--	--	--	--	--	--	--

natural gas (Table 2.6). As these dates are approached, price changes for sales both to electric utilities and to gas utility direct customers will change as natural gas from alternative sources is rolled (blended) in. In general, most changes in average prices will be gradual because of the rolled-in effects. One exception to this would be PALNG's entry into the market and the effect on natural gas costs for CEA. Increased costs to Chugach would show up in electrical energy costs to all consumers in the Cook Inlet region other than those served by AMP&L. Marginal prices of new sources of natural gas will, however, increase almost as step functions even though diluted by transmission costs downstream from the wellheads.[a]

The principal conclusions to be drawn from the Table 2.6 "Time Line" are as follows.

1. The question of whether to proceed with the PALNG project may be resolved in late 1982, and the uncertainty hanging over future gas prices for uncommitted gas should be resolved to some degree.

2. In the 1984-1986 period, problems of deliverability from the Kenai and North Cook Inlet Fields will increase; Beluga Field gas sales to CEA will reach the maximum take contract provision, and either a new contract will have to be negotiated for supplemental gas or additional gas purchased from AGAS. Regardless of specific outcomes, prices should increase significantly, at least for the electric utilities.

3. In the 1989-1991 period, natural gas committed for in-state consumption is exhausted and prices (in the extreme case) could rise to near the cost of distillate fuel oil if natural gas prices are deregulated. Although this might be the limit of the "opportunity cost," it is doubtful that the gas producers could obtain this

(a) The miscellaneous costs of gathering, compression, and transmission between the wellheads and the consumers are expected to remain constant in nominal dollars unless covered in contract terms. Declines in gas utility rate bases will be offset by increasing operation and maintenance costs or physical additions to improve deliverability, etc.

TABLE 2.6. Time Table of Expected Significant Changes in Cook Inlet Natural Gas Situation

Date		
1981	1)	Kenai Field gas to Alaska Pipeline Company. Price increase from 24¢/Mcf to 27¢/Mcf at wellhead.
	2)	North Cook Inlet gas to Alaska Pipeline Company. Expected to incur 10¢/Mcf compression charge (escalates at 6% annually).
	3)	Decision on Pacific Alaska LNG. Go-no go expected.
1984	1)	Phillips/Marathon contract with Tokyo Gas and Tokyo Electric expires. May be renewed for additional 5 years by mutual agreement.
	2)	State Royalty gas contract to Alaska Pipeline Company expires for North Cook Inlet Field.
	3)	Beluga Field gas sales to Chugach Electric reach maximum take provisions if sales increase as expected.
1985	1)	Earliest year for Pacific Alaska LNG start if project is to proceed.
	2)	If Pacific Alaska LNG starts, Beluga gas costs to Chugach Electric Association could increase from 21¢/Mcf to 85¢/Mcf if Beluga gas is taken.
	3)	Production from North Cook Inlet Field expected to start decline at 10% per year rate.
	4)	Kenai Field deliveries to Alaska Pipeline Company may start to decline.
1986	1)	Kenai gas price to Alaska Pipeline Company could increase to average of new sales to third parties.
1989	1)	Swanson River Oil Field blowdown expected to start at maximum rate of about 18.2 Bcf/year.
	2)	If Chugach draws supplemental gas from AGAS rather than exceed maximum take from Beluga, AGAS reserves are exhausted.
1990	1)	Gas reserves currently committed to AGAS are exhausted irrespective of above Chugach shift.
1991	1)	All gas reserves counted for in-state consumption are exhausted.
	2)	Kenai Field gas committed to Collier Carbon and Chemical Company exhausted.
1993	1)	Kenai Field gas committed to Alaska Pipeline Company exhausted if take remains steady at 1979 rate.
1995	1)	Beluga Field gas committed to Chugach is exhausted if Chugach does not exceed maximum take provisions.
	2)	Beluga Field gas committed to CEA exhausted if it does not shift supplemental gas requirements to AGAS and increase as expected.
1998	1)	Chugach Electric Association contract for Beluga River gas expires.
	2)	Beluga River gas committed to Chugach is exhausted if take remains steady at 1979 rate.
1999	1)	Swanson River Field blowdown expected to end.

price. It thus appears that the major near-term turning points are about 1985 and 1990. Significant changes in prices should start to occur even with continued natural gas price regulation at these dates.

2.2.3 Future Price Scenarios[a]

Pacific Alaska LNG Associates Project Does Not Proceed

This scenario is the one most favorable to Alaskan consumers because adverse contract terms are not called into play and a "buyer's market" prevails. Under this scenario, it is assumed that AGAS continues to take as much gas as possible from the Kenai and West Fork Fields and about 4 Bcf per year of royalty natural gas from the North Cook Inlet Field (highest cost). Natural gas deliveries to the electric utilities are interruptible; but, AGAS installs an LNG storage facility in about 1985, purchasing liquefaction services from the existing Phillips/Marathon LNG plant at least to assure deliverability to gas utility customers. Ultimately, this additional LNG storage depends on the size and conditions of future gas contracts and the disposition of the royalty gas. Electric utilities must increasingly shift to distillate turbine fuels for periods of peak demand.

It is also assumed that AGAS arranges for supplemental gas supply over and above 1985 supply estimates from either the Kenai or Beaver Creek Fields at a higher price. This price is rolled into all final sale prices without preference to any class of customers. This scenario also assumes that gas availability from the Kenai Field declines at about 10% per year starting in 1986. Alaska Gas and Services' weighted average wellhead price plus applicable taxes and other charges therefore increase as shown in Table 2.7 and Figure 2.2.

Chugach Electric Association depends principally (82% in 1979) on a currently favorable contract for Beluga River Field gas. The Beluga generation plants are base and intermediate load suppliers and CEA's other combustion turbines, supplied by AGAS, are used primarily for peaking duty.

(a) For the purposes of these scenarios, an interconnection between the Cook Inlet and Fairbanks load centers does not exist. If interconnection occurs, drawdown of Cook Inlet gas reserves are accelerated and supplemental gas is introduced slightly sooner.

TABLE 2.7. Estimated Gas Price - Purchases by Alaska Gas and Service Company Without Pacific Alaska LNG, 1982 $'s, 0% Inflation

Year	North Cook Royalty Bcf/Yr	North Cook Royalty $/Mcf	Kenai Plus North Fork Bcf/Yr	Kenai Plus North Fork $/Mcf	Non-Royalty Supplemental Gas Bcf/Yr	Non-Royalty Supplemental Gas $/Mcf[a]	Total AGAS Bcf/Yr	Weighted Ave. Price to AGAS $/Mcf[b]
1980	4.00 (2.68)[c]	2.50 (1.18)	27.35 (29.44)	0.64 (0.58)	0	--	31.35 (32.12)	1.13 (0.63)
1981	4.00 (1.03)	2.56 (2.10)	28.57 (30.85)	0.64 (0.63)	0	--	32.57 (31.88	1.11 (0.68)
1982	4.00	2.63	29.63	0.64	0	--	33.63	1.12
1983	4.00	2.68	30.84	0.64	0	--	34.84	1.10
1984	4.00	2.75	32.11	0.64	0	--	36.11	1.11
1985	4.00	2.82	33.44	0.64	0	--	37.44	1.12
1986	4.00	2.89	30.40	0.64	4.60	3.14	39.00	1.41
1987	4.00	2.96	27.64	0.64	7.95	3.22	39.59	1.63
1988	4.00	3.03	25.12	0.64	8.31	3.30	37.43	1.73
1989	4.00	3.12	22.84	0.64	11.76	3.39	38.60	1.95
1990	4.00	3.18	20.76	0.64	15.08	3.45	39.84	2.20
1991	0	--	0	--	41.45	3.56	41.45	3.80
1992	0	--	0	--	43.14	3.65	43.14	3.89
1993	0	--	0	--	44.90	3.73	44.90	3.97
1994	0	--	0	--	46.74	3.82	46.74	4.06
1995	0	--	0	--	48.66	3.92	48.66	4.16
1996	0	--	0	--	50.55	4.01	50.55	4.25
1997	0	--	0	--	52.52	4.11	52.52	4.35
1998	0	--	0	--	54.56	4.23	54.58	4.47
1999	0	--	0	--	56.72	4.33	56.72	4.57
2000	0	--	0	--	58.94	4.46	58.94	4.70

(a) Price assumed comparable to North Cook Royalty gas plus production tax at wellhead and Pacific Rim gas price set by world oil price CIF.
(b) Includes delivery charge to Anchorage for assuring delivery during cold weather.
(c) Items in parentheses are actual quantities and prices for 1980 and 1981.

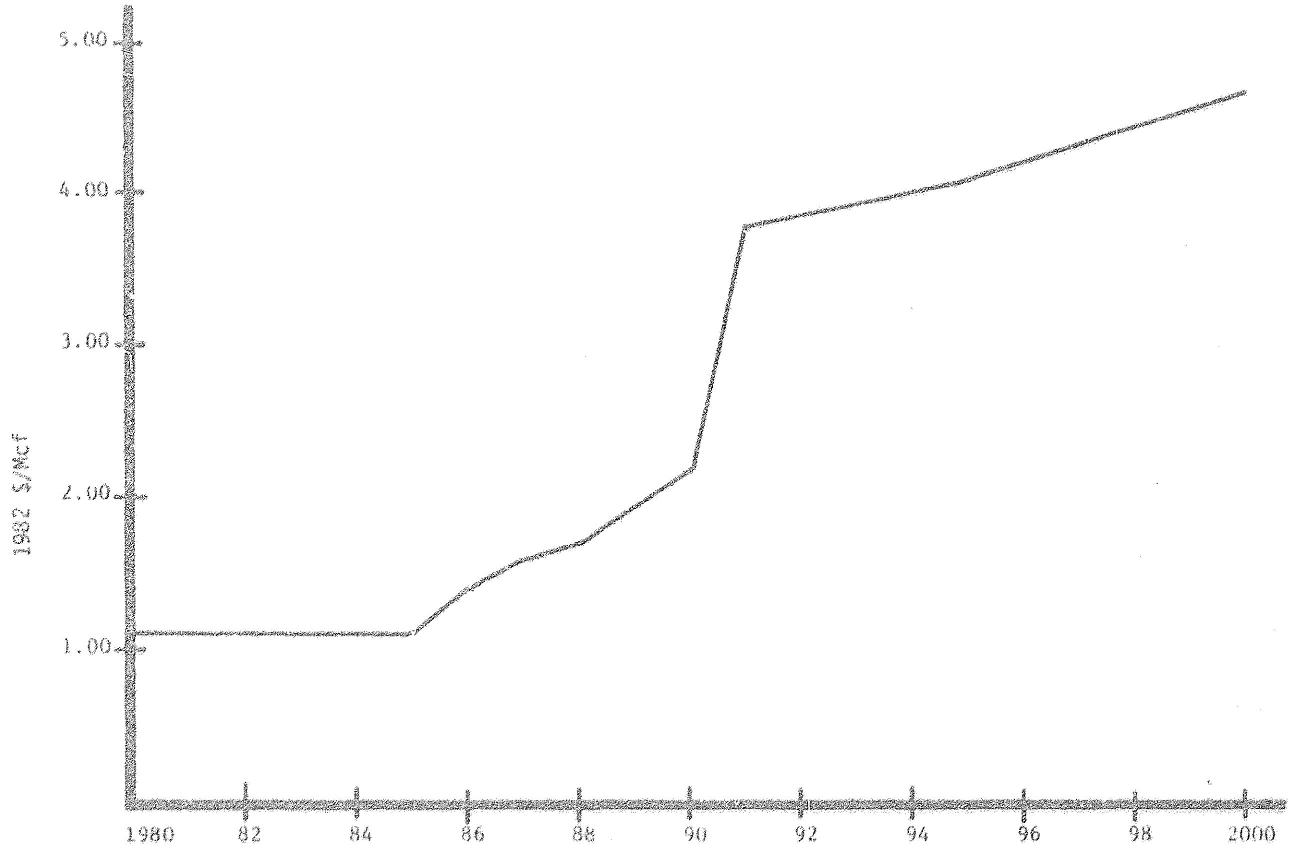

FIGURE 2.2. Weighted Average Natural Gas Acquisition Cost--Alaska Gas and Service Company Without Pacific Alaska LNG

For purposes of this analysis, it is assumed that CEA will continue to draw heavily on the Beluga River Field up to its contractual maximum take provisions. At that time (1985) CEA will either negotiate a supplemental gas supply contract with the Beluga producers or shift generation to capacity supplied by AGAS, whichever price is lower.[a] In either event, the price CEA most likely must pay would be the rolled-in price delivered by AGAS (Table 2.7 plus a gas transmission charge of about $0.26 Mcf). With these assumptions, the weighted average natural gas acquisition cost for CEA is developed in Table 2.8 and plotted in Figure 2.3.

(a) Ignoring any differences in electrical transmission costs or plant heat rates.

DISCOVERY DATE: na

FIELD OR UNIT: Kaldachabuna

INITIAL PRODUCTION: na

LOCATION: W. Side Cook Inlet (Onshore)

WELLS FLOWING: na SHUT IN: na

STATE ROYALTY: na

PRODUCTION 1979: na BCF

CUMULATIVE PRODUCTION 1/1/80: na BCF

OPERATOR: Simasko Production Co.

OTHER PARTICIPANTS: Union Oil Co.

ESTIMATED REMAINING RESERVES: na BCF, DATE:

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: BCF, DATE:

REMARKS:

1. Wildcat drilling in progress (Oil and Gas Journal, 12/8/80)
2. One mile north of Granite Point Field (T11N-R11W)

CONTRACT PROVISIONS:

DISCOVERY DATE: 10/11/59

FIELD OR UNIT: Kenai

INITIAL PRODUCTION: 1962

LOCATION: Kenai Peninsula

WELLS FLOWING: 37 SHUT IN: 1

STATE ROYALTY: ~ 3.09(1)

PRODUCTION 1979: 97.0 BCF

CUMULATIVE PRODUCTION 1/1/80: 995.1 BCF

OPERATOR: Union Oil Co.

OTHER PARTICIPANTS: Marathon
ARCO - 0.39%
Chevron - 0.39%

ESTIMATED REMAINING RESERVES: 1313 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE
Collier Carbon & Chemical	up to 585	12/5/77 (2)
Alaska Pipeline Co.	312	12/31/80 (2)
Standard Oil Co. of California/ARCO	400	1/1/66
Collier Carbon & Chemical	499	1/1/80 (3)
Standard Oil of California/ARCO	106	1/1/80 (3)

UNCOMMITTED REMAINING RESERVES: 370(3) BCF, DATE: 1/1/80

REMARKS:

1. Prior to transfer of portion to C.I.R.I. in 1980, current status unknown.
2. Letter Bill B. Hickman, Alaska Gas and Service Co. to W. H. Swift, January 13, 1981.
3. Battelle estimate based on AOGCC raw data.

CONTRACT PROVISIONS:

Collier Carbon and Chemical Company

Original contract dated 8/7/68, subsequently amended 11/1/77. Maximum delivery requirement - 130,000 Mcf/day (47.45 Bcf/year). Price (1/1/80) 61.0¢/Mcf, to be renegotiated by 1/1/81. Term - 20 years. Commitment subject to prior contractual agreements (i.e., subordinant to all other present contracts).

KENAI FIELD (continued)

CONTRACT PROVISIONS:

Alaska Pipeline Corporation

Original contract executed 5/13/60; subsequent amendments occurred 5/1/67 10/1/67, 1/1/72, and 1/1/75. The last two modifications cancelled all prior amendments.

Commitment: 550 Bcf on date of execution, may substitute from other sources. Remaining reserves as of 12/1/80, 312 Bcf.

Minimum take of 72,000 Mcf/day (26.28 B[illegible]/year) until 12/31/85. After that date, minimum take is the lesser of 72,000 Bcf or 75% of seller's delivery capacity. Maximum take is 160,000 Mcf/day until 12/31/85.

Price: 1/1/76 to 12/31/80 -- $0.24/Mcf
1/1/81 to 12/31/92 -- $0.27/Mcf
1/1/86 to 12/31/92 -- the greater of 27¢ or the average price of gas sales in the Cook Inlet area and received by sellers for new sales to third parties.

Deliverability Charge: $0.29/Mcf on 1/1/80 escalating by producer price index.

Standard Oil Company of California and Atlantic Richfield (Rental Gas)

Executed: 1/1/66

Maximum take: 400 Bcf total

1st 5 years -- 45 Bcf/year
2nd 5 years -- 27 Bcf/year
3rd 5 years -- 16 Bcf/year
4th 5 years -- 12 Bcf/year
21st year to blowdown -- 8 Bcf/year

Minimum take: 150 Bcf -- 1/1/66-12/31/70

Price (Rental Charge): ranges from 8.1 to 8.9¢/Mcf depending on delivery pressure. For royalty purposes, price is taken as 16¢/Mcf.

KENAI FIELD (continued)

CONTRACT PROVISIONS:

Return after Commencement of Blowdown:

Anticipated to occur about 1989 at an average minimum rate of 18.2 Bcf 18.2 Bcf/year over 10 year period (182 Bcf cumulative). Maximum return delivery rate.

City of Kenai

~~Contract~~ executed 5/17/66 for term of 20 years. Apparently the contract has never been envoked.

Anchorage Municpal Light and Power

State royalty gas contract executed 5/5/80 for all royalty gas over 20 year period.

Price: Equal to royalty payments state would have received if it had take its royalty in-value plus additional transportation costs. Proforma (1979) prices would be \$0.8213/Mcf to A Gas, \$0.6631/Mcf to AML&P. Wheeling cost \$0.24/Mcf.

This contract is yet to be exercised due to (1) Pricing dispute and (2) transfer of some of the state lands in the lease area to Cook Inlet Region, Inc.

Tokyo Gas and Tokyo Electric

Some of the gas contracted for with Phillips/Marathon LNG is supplied from the Kenai Field (18.77 Bcf in 1979). See data sheets on North Cook Inlet Field.

DISCOVERY DATE: 10/1/75

FIELD OR UNIT: Lewis River

INITIAL PRODUCTION: na

LOCATION: W. Side Cook Inlet (Onshore)

WELLS FLOWING: 0 SHUT IN: 2

STATE ROYALTY: 0

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: 0 BCF

OPERATOR: Cities Service Oil Co.

OTHER PARTICIPANTS: Pacific Lighting

ESTIMATED REMAINING RESERVES: 90 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE
Pacific Alaska LNG Assoc.	44 or 100%	1/1/80

UNCOMMITTED REMAINING RESERVES: 0 BCF, DATE: 1/1/80

REMARKS:

1. Remaining gas reserves estimated by DeGolyer and MacNaughton at 21.78 Bcf as of 11/1/75.
2. No pipeline connections. Located NW of Ivan River Field.

CONTRACT PROVISIONS:

Pacific Alaska LNG Associates/Cities Service

Effective Date: July 1, 1982 or date of initial delivery of gas
Term: 20 years, 22 Bcf
Price: $1.48/Mcf as of January 1, 1978, escalating 1¢/quarter. If deregulate, then average of 3 highest prices then being paid in Cook Inlet to pipeline companies for resale.

LEWIS RIVER (continued)

CONTRACT PROVISIONS: (continued)

Pacific Alaska LNG Associates/Pacific Lighting Gas Development

Essentially same as Cities Service contract except that if deregulated, the price is the higher of (a) price paid to an Alaskan producer under contract executed after 1/1/77, or (b) weighted average paid by Southern California Gas Company and PG&E for gas less transportation costs. Price is also escalated by the producer price index (PPI = 195.2 - May 1977).

DISCOVERY DATE: 12/2/68

FIELD OR UNIT: McArthur River

INITIAL PRODUCTION: 1/69

LOCATION: W. Side Cook Inlet (Offshore)

WELLS FLOWING: 5 SHUT IN: 0

STATE ROYALTY: 12.5% in Value

PRODUCTION 1979: 7.76 BCF

CUMULATIVE PRODUCTION 1/1/80: 66.90 BCF

OPERATOR: Union Oil Co.

OTHER PARTICIPANTS: Atlantic Richfield (5%?)

ESTIMATED REMAINING RESERVES: 78 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 78 BCF, DATE: 1/1/80

REMARKS:

1. Lease use.

CONTRACT PROVISIONS:

DISCOVERY DATE: 5/1/66

FIELD OR UNIT: Nicolai Creek

INITIAL PRODUCTION: 10/68

LOCATION: W. Side Cook Inlet (On, Offshore)

WELLS FLOWING: 0 SHUT IN: 4

STATE ROYALTY: 12.5%

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: 1.06 BCF

OPERATOR: Texaco

OTHER PARTICIPANTS:

ESTIMATED REMAINING RESERVES: 17 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 17 BCF, DATE: 1/1/80

REMARKS:

1. Lease use

CONTRACT PROVISIONS:

DISCOVERY DATE: 9/1/62 FIELD OR UNIT: North Cook Inlet

INITIAL PRODUCTION: 3/69 LOCATION: North Cook Inlet (Offshore)

WELLS FLOWING: 11 SHUT IN: 1 STATE ROYALTY: 12.5%

PRODUCTION 1979: 49.4 BCF CUMULATIVE PRODUCTION 1/1/80: 456.5 BCF

OPERATOR: Phillips Petroleum Co. OTHER PARTICIPANTS: Marathon
Chevron
AMOCO
CABOT

ESTIMATED REMAINING RESERVES: 1074 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE
Tokyo Gas and Electric	∿ 191	1/1/81
Alaska Pipeline Co.	∿ 26.8 (Royalty)	1/1/81

UNCOMMITTED REMAINING RESERVES: ∿806 BCF, DATE: 1/1/81

REMARKS:

The 1979 average production rate can be sustained until 1985 after which the volumes will decline at about 10% per year. (Letter, John Horn, Phillips Petroleum, Co. to D. G. Wold, Royalty Oil and Gas Development Advisory Board, March 3, 1977).

Alaska Pipeline Co. does not expect a full take of the royalty share but rather 15 to 20 Bcf over the remaining term of their contract or about 5 Bcf/year.

CONTRACT PROVISIONS:

Tokyo Gas and Tokyo Electric Co.

These contracts (dated March 6, 1967) call for LNG delivery in Japan of ∿48.6 Bcf/year. The term is from June 1, 1969 to June 1, 1984 and may be extended by mutual agreement an additional five years.

Price provisions are negotiable but apparently are tied to prices the buyers may negotiate with other sellers of LNG and hence are related to world oil prices. The formula used for calculating the well head price (WHP) is:

WHP = (CIF Price in Japan)(0.36) - \$0.055 = \$/MMBtu

CONTRACT PROVISIONS:

Tokyo Gas and Tokyo Electric Co.

The 0.36 factor corrects for liquefaction and transportation costs, \$0.055/MMBtu covers pipeline costs from the North Cook platform to the Kenai LNG Plant.[a] Wellhead price behavior during 1980 was as follows:

Month	LNG CIF Price \$/MMBtu	Weighted Average World Oil Price \$/MMBtu	Wellhead Price \$/MMBtu
1	3.36	4.92	1.1541
2	3.36	-	1.1541
3	3.36	-	1.1541
4	4.97	-	1.7337
5	5.25	-	1.8345
6	5.40	5.43	1.8885
7	5.46	-	1.9101
8	5.555	-	1.9425
9	5.72	-	2.0037
10	5.85	-	2.0505
11	5.79	-	2.0289
12	5.89	5.74	2.0649

Alaska Pipeline Co. (State Royalty)

This contract was entered into April 11, 1977 and runs to June 1, 1984. Quantity is on a best effort basis with the intent not to take less than 3 Bcf per year. Pricing provisions and market conditions are such that Alaska Pipeline Company (APC) pays the same wellhead price as is payed by Marathon and Phillips for that royalty gas taken in value (see contract noted above). The cost of the gas to APC over and above the wellhead price includes: (1) a gathering charge of \$0.10/Mcf with such charge escalating at 6% per year from April 1977 (\$0.119/Mcf in mid-1980) and (2) a compression charge of \$0.10/Mcf increasing at a rate of 6% per year from date of installation of compression facilities. Alaska Gas and Service Co. advises that the compressors have been installed but not yet used. They expect that this could occur at any time.

(a) Letter from John Horn, Phillips Petroleum Co. to Robert E. LeResche, May 29, 1980.

DISCOVERY DATE: 12/20/65

FIELD OR UNIT: North Fork

INITIAL PRODUCTION: na

LOCATION: Kenai Peninsula near Homer

WELLS FLOWING: 0 SHUT IN: 1

STATE ROYALTY: 0

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: 0.1 BCF

OPERATOR: Chevron USA

OTHER PARTICIPANTS:

ESTIMATED REMAINING RESERVES: 12 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 12 BCF, DATE: 1/1/80

REMARKS:

1. Remote from existing pipelines

CONTRACT PROVISIONS:

DISCOVERY DATE: 11/15/64

FIELD OR UNIT: N. Middle Ground Shoal

INITIAL PRODUCTION: na

LOCATION: Cook Inlet - Offshore

WELLS FLOWING: 0 SHUT IN: 1

STATE ROYALTY: 12.5

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: na BCF

OPERATOR: Amoco Production Co.

OTHER PARTICIPANTS: Shell (?)

ESTIMATED REMAINING RESERVES: na BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: BCF, DATE:

REMARKS:

CONTRACT PROVISIONS:

DISCOVERY DATE: 8/4/61

FIELD OR UNIT: Sterling

INITIAL PRODUCTION: 5/62

LOCATION: Kenai Peninsula

WELLS FLOWING: 1 SHUT IN: 1

STATE ROYALTY: 2.72237 in Value

PRODUCTION 1979: 0.02543 BCF

CUMULATIVE PRODUCTION 1/1/80: 1.961 BCF

OPERATOR: Union Oil Co.

OTHER PARTICIPANTS: Marathon - 50% (?)

ESTIMATED REMAINING RESERVES: 23 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 23 BCF, DATE: 1/1/80

REMARKS:

CONTRACT PROVISIONS:

Original to Sport Lake Greenhouses (11/1/73), assigned to Peninsula Greenhouses (2/18/76). Quantity "... as may be produced and available from time to time but not to exceed 300 Mcf/day and not more than 50,000 Mcf in any one year." May be terminated by either party on 30 days notice. Price not available.

DISCOVERY DATE: na

FIELD OR UNIT: Stump Lake

INITIAL PRODUCTION: na

LOCATION: W. Side Cook Inlet (Onshore)

WELLS FLOWING: na SHUT IN: na

STATE ROYALTY: na

PRODUCTION 1979: na BCF

CUMULATIVE PRODUCTION 1/1/80: na BCF

OPERATOR: Chevron, USA

OTHER PARTICIPANTS: Pacific Lighting

ESTIMATED REMAINING RESERVES: na BCF, DATE:

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: BCF, DATE:

REMARKS:

1. Near Ivan River Field
2. Potential discovery - indefinite confidentiality date

CONTRACT PROVISIONS:

DISCOVERY DATE: 8/24/57

FIELD OR UNIT: Swanson River

INITIAL PRODUCTION: na

LOCATION: Kenai Peninsula

WELLS FLOWING: 1 SHUT IN: 5

STATE ROYALTY: ~ 3.09%

PRODUCTION 1979: 120.3 Injection BCF

CUMULATIVE PRODUCTION 1/1/80: 1,173.7 Injection BCF

OPERATOR: Chevron USA

OTHER PARTICIPANTS: Atlantic Richfield
Union Oil Co. - 1.51%
Marathon Oil Co. - 1.51%

ESTIMATED REMAINING RESERVES: See Remarks BCF, DATE:

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 242 BCF, DATE: 1/1/80

REMARKS:

1. Primarily an oil field. Rental gas from Kenai Field being injected for pressure maintenance. Blowdown expected to commence 1/89.
2. Original indigenous reserves estimated at 59.6 Bcf. Anticipated recovery of injected gas on blowdown estimated at 182 Bcf for a total of about 242 Bcf.

CONTRACT PROVISIONS:

DISCOVERY DATE: 6/1/65

FIELD OR UNIT: Trading Bay

INITIAL PRODUCTION: 12/68

LOCATION: Cook Inlet (Offshore)

WELLS FLOWING: na SHUT IN: na

STATE ROYALTY: 12.5%

PRODUCTION 1979: 0.7705 BCF

CUMULATIVE PRODUCTION 1/1/80: 0.822 BCF

OPERATOR: Union Oil Co.

OTHER PARTICIPANTS: Atlantic Richfield
Texaco, Inc.

ESTIMATED REMAINING RESERVES: na BCF, DATE: ____

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: ____ BCF, DATE: ____

REMARKS:

1. Casing head gas, lease use

CONTRACT PROVISIONS:

DISCOVERY DATE: na

FIELD OR UNIT: Trail Ridge

INITIAL PRODUCTION: na

LOCATION: 55 m NW of Anchorage
T20N - R10W

WELLS FLOWING: 0 SHUT IN: 0

STATE ROYALTY: na

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: 0 BCF

OPERATOR: Union Oil Co.

OTHER PARTICIPANTS:

ESTIMATED REMAINING RESERVES: na BCF, DATE:

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: BCF, DATE:

REMARKS:

1. Wildcat well drilling below 13,100 feet (Oil and Gas Journal, 12/8/80)

CONTRACT PROVISIONS:

DISCOVERY DATE: 11/28/65

FIELD OR UNIT: Tyonek

INITIAL PRODUCTION: na

LOCATION: W. Side Cook Inlet (Onshore)

WELLS FLOWING: 0 SHUT IN: 3

STATE ROYALTY: 0% (C.I.R.I.)

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: na BCF

OPERATOR: Pacific Lighting, SIMPCO

OTHER PARTICIPANTS:

ESTIMATED REMAINING RESERVES: na BCF, DATE:

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE
Pacific Alaska LNG Assoc.	100%	

UNCOMMITTED REMAINING RESERVES: BCF, DATE:

REMARKS:

1. Also identified as Albert Kaloa and Moquawki Fields.

CONTRACT PROVISIONS:

Pacific Alaska LNG Associates executed 8/17/77. Take or pay starting 7/1/81. Estimated reserves to be determined by DeGolyer and MacNaughton. Price: $1.48/Mcf as of January 1, 1978 escalating at 1¢/quarter. On deregulation, pay same as for Lewis River Field contract.

DISCOVERY DATE: 3/29/62

FIELD OR UNIT: West Foreland

INITIAL PRODUCTION: na

LOCATION: W. Side Cook Inlet

WELLS FLOWING: 0 SHUT IN: 1

STATE ROYALTY: 0

PRODUCTION 1979: 0 BCF

CUMULATIVE PRODUCTION 1/1/80: 0 BCF

OPERATOR: Amoco Production Co.

OTHER PARTICIPANTS:

ESTIMATED REMAINING RESERVES: 20 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE

UNCOMMITTED REMAINING RESERVES: 20 BCF, DATE: 1/1/80

REMARKS:

1. Semi-remote field - could be connected to existing submarine pipeline to Nikiski.

CONTRACT PROVISIONS:

DISCOVERY DATE: 9/26/60

FIELD OR UNIT: West Fork

INITIAL PRODUCTION: 10/78

LOCATION: Kenai Peninsula

WELLS FLOWING: 1 SHUT IN: 0

STATE ROYALTY: 0%

PRODUCTION 1979: 0.7705 BCF

CUMULATIVE PRODUCTION 1/1/80: 0.8220 BCF

OPERATOR: Halbouty Alaska

OTHER PARTICIPANTS:

ESTIMATED REMAINING RESERVES: 7 BCF, DATE: 1/1/80

DEDICATED REMAINING RESERVES:

BUYER	BCF	DATE
Alaska Pipeline Co.	?	

UNCOMMITTED REMAINING RESERVES: BCF, DATE:

REMARKS:

1. Alaska Gas and Service Co. indicates that this field is not a significant source of supply, a single well field that produces less than 2,000 Mcf daily. Operating problems may result in shut in (letter Bill B. Hickman, Alaska Gas and Service Co. to W. H. Swift, January 13, 1981).

CONTRACT PROVISIONS:

Alaska Pipeline Co.