513 HRES HB 854 (NOTEBOOK)

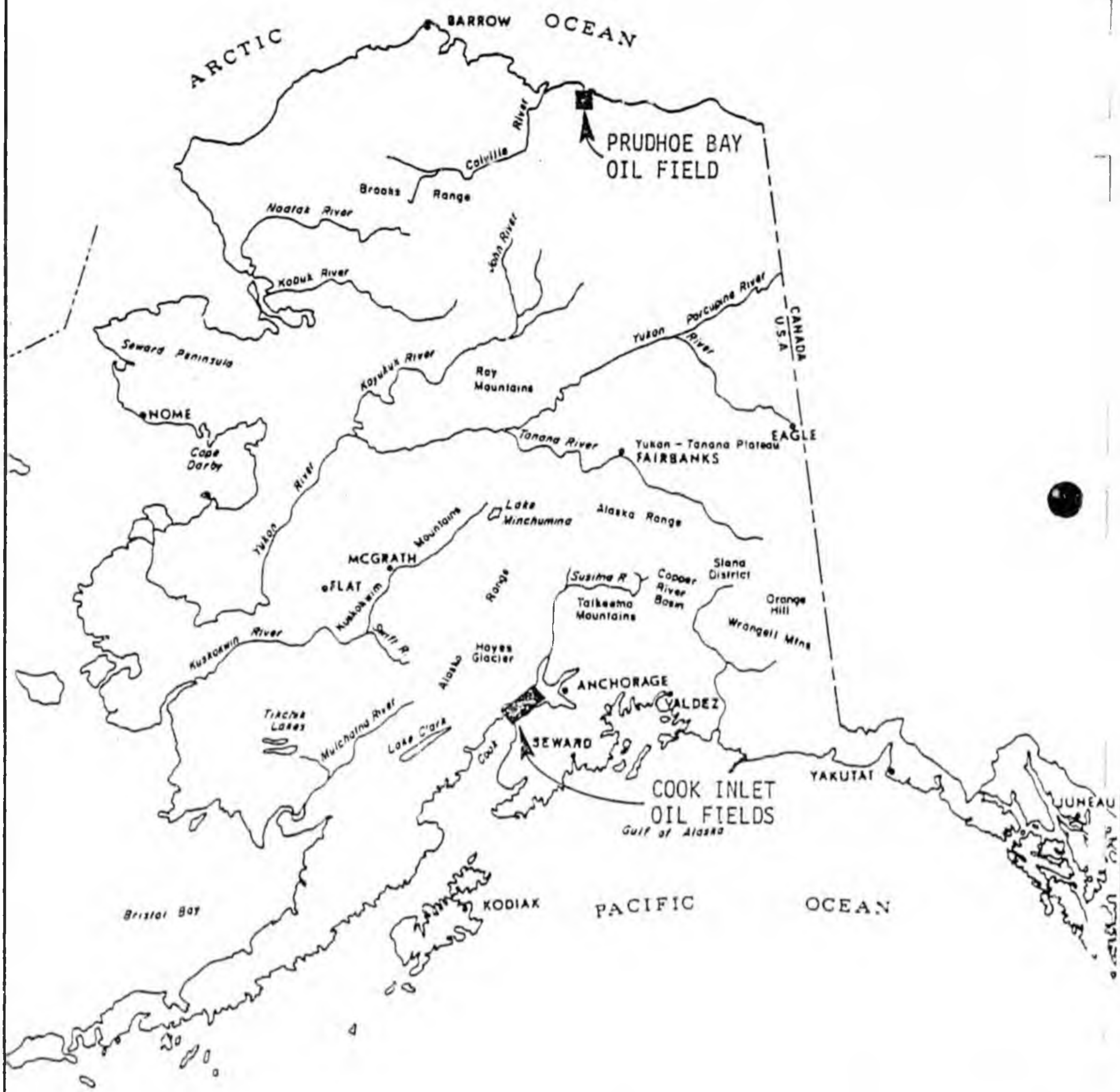
There is no such thing as a "typical" oil field, but certain physical characteristics and development activities are common to all fields in a geographic region such as Alaska. The model oil fields used in this study are based on Trading Bay, Granite Point and McArthur River Oil Fields in Cook Inlet and Prudhoe Bay on the North Slope. Table K-1 lists all of the physical characteristics of the model fields. Note that reserves are listed as recoverable reserves. In actuality, the oil in place (i.e. in the ground) can be as much as three times greater than the recoverable oil. This study assumes an average recovery rate of 30% using secondary recovery techniques. Thus, Mercury Oil Field with recoverable reserves of 50 million barrels actually may have 166.67 million barrels of oil in the ground. The largest model field, Jupiter, has recoverable reserves of five billion barrels and may have oil-in-place of 16.67 billion barrels.

The physical parameters, such as the feet of pay, acres occupied, porosites and permeabilities, for each model field are all adapted from the corresponding real field as are the gas-oil ratios, oil gravities, and sulfur contents. In some cases, the acres occupied by a model field are scaled down from the real fields to reflect the differences in amounts of reserves.

Although most of the real Alaskan fields are producing oil from several pools, the leasing study fields are modeled using one producing pool. Consultation with petroleum engineers of the Division of Oil and Gas Conservation committee indicated that this assumption will not appreciably affect the computer results, or the validity of the conclusions.

COOK INLET AND PRUDHOE BAY OIL FIELDS

STATE OF ALASKA



COOK INLET AND PRUDHOE BAY OIL FIELDS

The Sensitivity of State Petroleum
Income to Various Leasing Methods

January 1977 Figure K-1

PHYSICAL PARAMETERS
OF THE MODEL FIELDS

FIELD NAME	FIELD CLASSIFICATION	RECOVERABLE RESERVES (MILLION BARRELS)	FEET OF PAY (FEET)	AREA (ACRES)	AVERAGE POROSITY (%)	AVERAGE PERMEABILITY (MD.)	NUMBER OF POOLS	DEPTH TO POOL (FEET)	GAS/OIL RATIO (AVERAGE OVER FIELD LIFE) (SCF/STB)	AVERAGE GRAVITY (API°)	SULFUR CONTENT OF CRUDE (WT. %)
MERCURY[1]	MARGINAL	50±	100-300	1,400	16.1	130	1	7,500	300	32.8	.08
MARS[2]	SMALL	110±	250-600	3,200	14	10	1	7,750	400	42.5	.02
VENUS[3]	MEDIUM	600±	0-450	12,400	14.8	73.3	1	9,100	400	34.6	.11
NEPTUNE[4]	LARGE	1000±	0-444	19,000	22	265	1	8,200	730	28	1.12
JUPITER[4]	GIANT	5000±	0-444	94,000	22	265	1	8,200	730	28	1.12

[1]Based on Trading Bay Field - Recoverable reserves of 75 million barrels (MMB)

[2]Based on Granite Point Field - Recoverable reserves of 110 million barrels

[3]Based on McArthur River Field - Recoverable reserves of 503 million barrels

[4]Based on Prudhoe Bay Field - Recoverable reserves of 8 billion barrels

PHYSICAL PARAMETERS OF THE MODEL FIELDS

The Sensitivity of State Petroleum Income to Various Leasing Methods

January 1977 Table K-1

Figure K-2 illustrates the development history of Northern Cook Inlet oil fields upon which the model fields development histories are based. For the purpose of this study, time zero is the lease sale date. All development takes place in relation to that date. It can be seen on Table K-2 that the average length of time from lease sale to production in the Cook Inlet has been approximately five years; therefore, the study uses that time span, also.

Table K-3 is a compilation of the production histories of the model fields. Based on the accepted historical average, each model field requires three exploratory wells. Mercury, Mars and Venus are located offshore and Neptune and Jupiter are situated onshore. Mercury uses two offshore production platforms while Mars and Venus require three. The number of production wells ranges from 32 to 240 with the average initial production rates ranging from 12,500 to 9,120,000 barrels per month. Eight to eleven years elapse between the lease sale date and the date when the fields reach peak production. Peak production rates range from 400,000 to 29,000,000 barrels per month and lasts from five to seven years, depending on the particular model field.

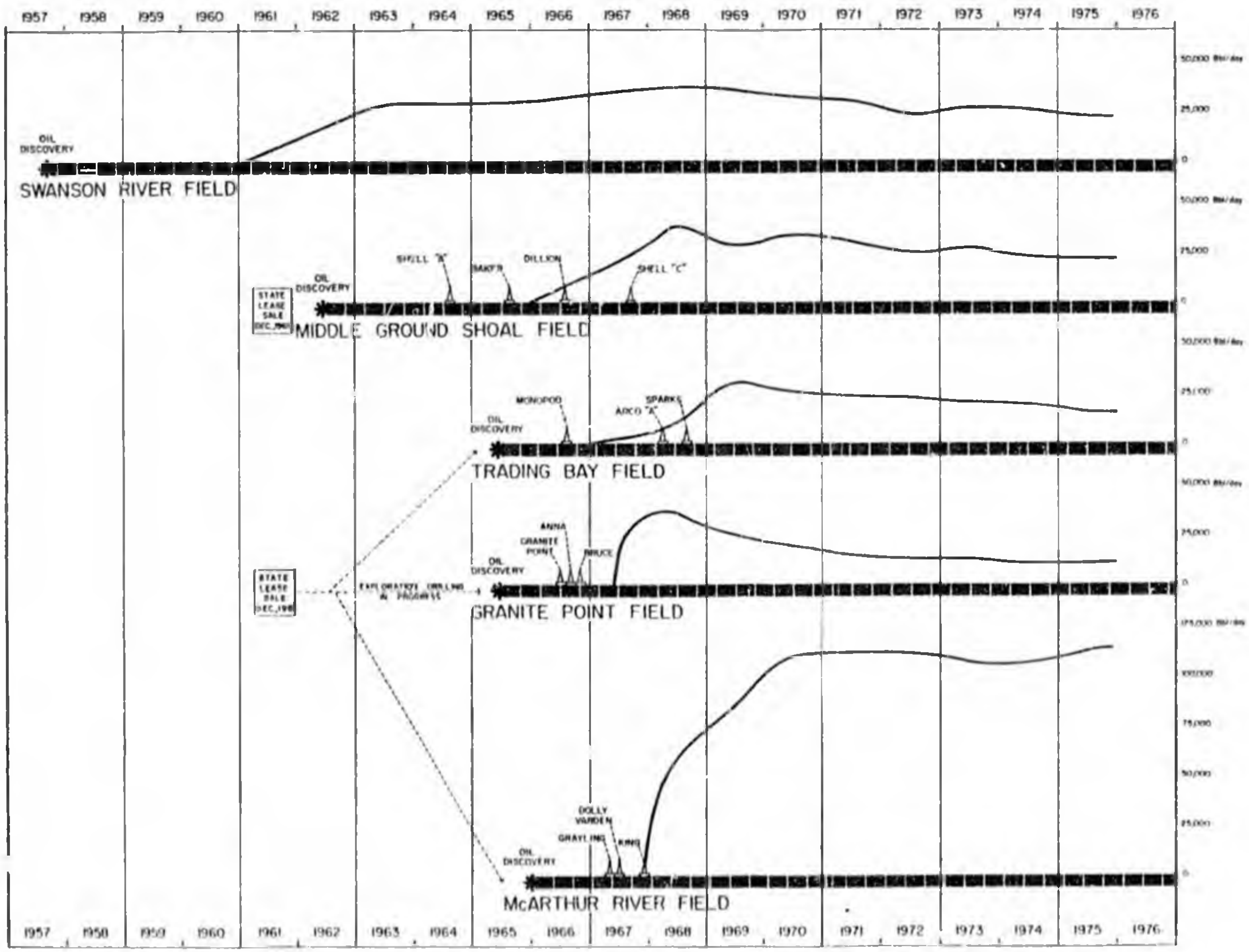
Based on the history of Alaskan oil development, it is also assumed that all of the model fields require water injection for secondary recovery pressure maintenance, which begins from eight to twelve years after the lease sale. The number of injection wells range from 13 to 30.

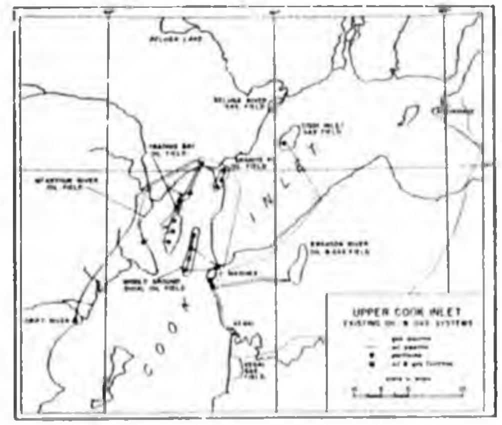
Production of the various fields begins to decline from 12 to 16 years after the lease sale. Decline rates vary from 10 to 20 percent, and the production rate at the end of the economic life of the fields range from 25,000 to 330,000 barrels per month.

Figures K-3 through K-7 illustrate the production histories of their model fields. Mercury oil fields' economic life (years of production) is estimated to be 27 years. All of the other larger fields may produce for 30 years. These are based on accepted historic averages. The length of any fields' economic life is very difficult to predict because of the uncertainties involved in changing technology and economics. It is possible that improved secondary recovery techniques and higher oil prices may extend production years far beyond the above mentioned estimations. Economic life also varies with the type of leasing method employed. Some of the computer analyses did run the economic lives beyond 30 years, but the amount of oil produced during that time is very insignificant when compared to the total production.

In the actual analysis for a future lease sale, engineering/geologic models of the potential risk oil fields to be leased will be modeled in the same manner as presented here. The expertise and knowledge gained through this modelling program will be invaluable for assessing the cost benefits of developing Alaska's energy and mineral resources.

NORTH COOK INLET OIL FIELD DEVELOPMENT HISTORY





NORTH COOK INLET
OIL FIELD DEVELOPMENT HISTORY

State of Alaska
Department of Natural Resources

October, 1976 by Edward Cole

Figure K2

UPPER COOK INLET OIL FIELD STATISTICS

FIELD	SALE DATES	DISCOVERY	TIME TO DISCOVERY	FIRST PRODUCTION	TIME TO PRODUCTION
Middle Ground Shoal	12/19/61	6/10/62	.5 years	12/65	4.0 years
McArthur River	12/19/61 7/11/62	10/24/65	4.0 "	11/67	5.9 "
Trading Bay	12/19/61 7/11/62	6/01/65	3.5 "	1/67	5.1 "
Granite Point	7/19/61 7/11/62	6/09/65	4.0 "	3/67	5.7 "
Swanson River	Federal non-competitive leases	8/24/57		8/61	
					20.7 "
				Average	5.2 "

Table K-2

PRODUCTION HISTORIES OF MODEL FIELDS

Fields: Name	Fields: Class.	Exploratory Wells: No. of Wells	Exploratory Wells: Yrs. to Compl.	Number of: Plat-forms	Number of: Prod. Wells	Initial[5] Prod. Rate	Water Inject.: No. of Wells	Water Inject.: W. I. starts	Prod. Decline: Decline starts	Prod. Decline: Decline Rate	At Assumed Economic Limit: Final Prod. Rate	At Assumed Economic Limit: Field Life*
		(No.)	(Yrs.)	(No.)	(No.)	(BBL/MO.)	(No.)	(Yr.)	(%)	(Yr.)	(BBL/MO.)	(Yr.)
Mercury[1]	Marginal	3	1,2,2,5	2	32	12,500	13	9	15	13	25,000	27
Mars[2]	Small	3	1,2,2,5	3	40	127,700	16	9	11	12	70,000	30
Venus[3]	Medium	3	1,2,2,5	3	63	760,000	22	8	15 @ 4 yrs. 20 @ 13 yrs.	16	85,000	30
Neptune[4]	Large	3	1,2,2,5	N/A	95	3,040,000	20	11	10 @ 3 yrs. 15 @ 5 yrs. 20 @ 13 yrs.	15	100,000	30
Jupiter[4]	Giant	3	1,2,2,5	N/A	240	9,120,000	30	12	10 @ 5 yrs. 15 @ 5 yrs. 20 @ 9 yrs.	16	330,000	34

*This data may vary with the use of different leasing methods.

[1]Based on Trading Bay Field - Recoverable reserves of 75 million barrels (MMB)
[2]Based on Granite Point Field - Recoverable reserves of 110 million barrels.
[3]Based on McArthur River Field - Recoverable reserves of 503 million barrels.
[4]Based on Prudhoe Bay Field - Recoverable reserves of 8 billion barrels.
[5]For all cases, production starts 5 years after the lease sale.

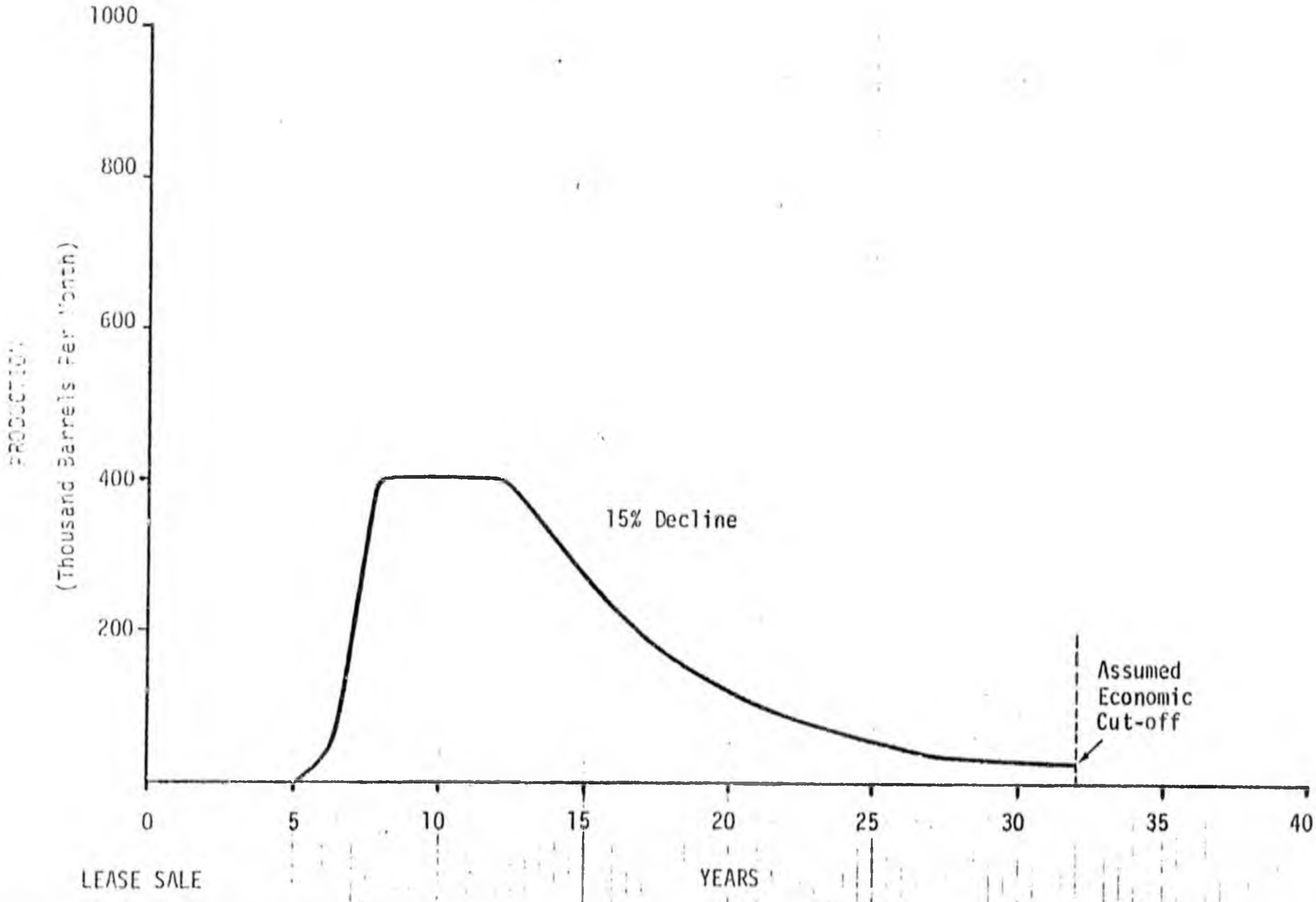
PRODUCTION HISTORIES OF MODEL FIELDS

The Sensitivity of State Petroleum Income to Various Leasing Methods

January, 1977 Table K-3

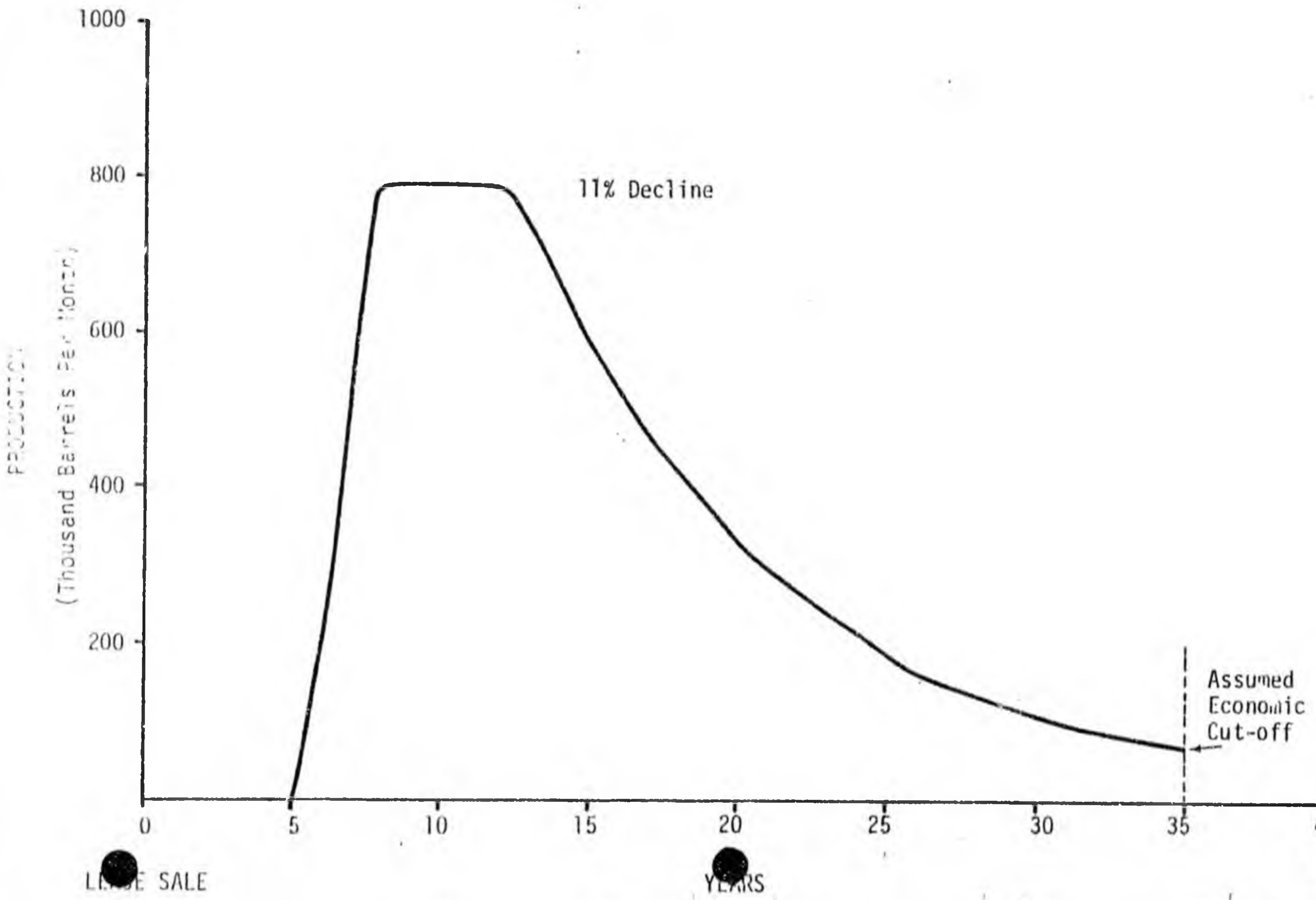
PRODUCTION HISTORY OF MERCURY OIL FIELD

(Recoverable Reserves 50± Million Barrels)



PRODUCTION HISTORY OF MARS OIL FIELD

(Recoverable Reserves 110± Million Barrels)



PRODUCTION HISTORY OF VENUS OIL FIELD

(Recoverable Reserves 600± Million Barrels)

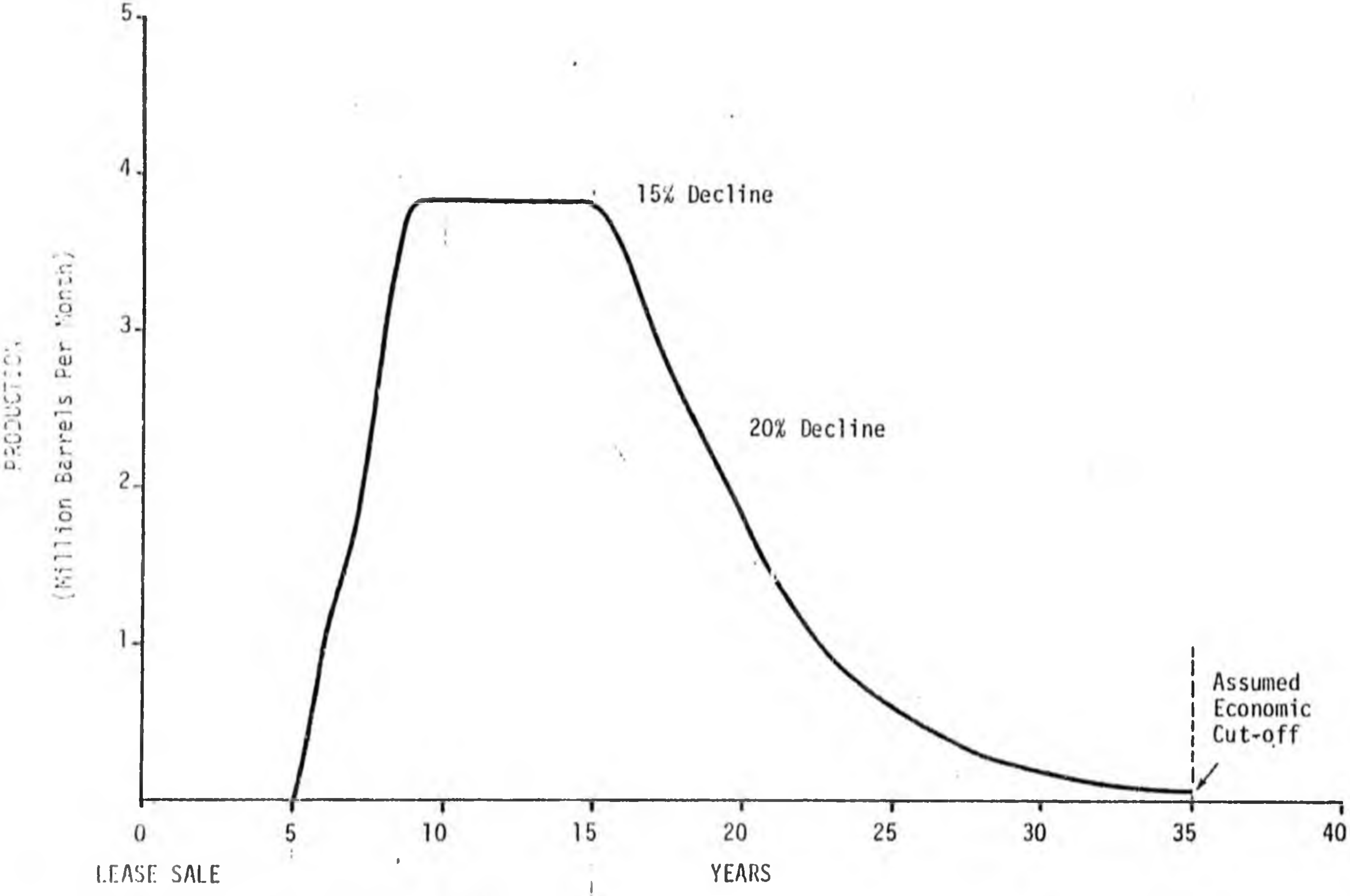


Figure K-5

PRODUCTION HISTORY OF NEPTUNE OIL FIELD

(Recoverable Reserves 1± Billion Barrels)

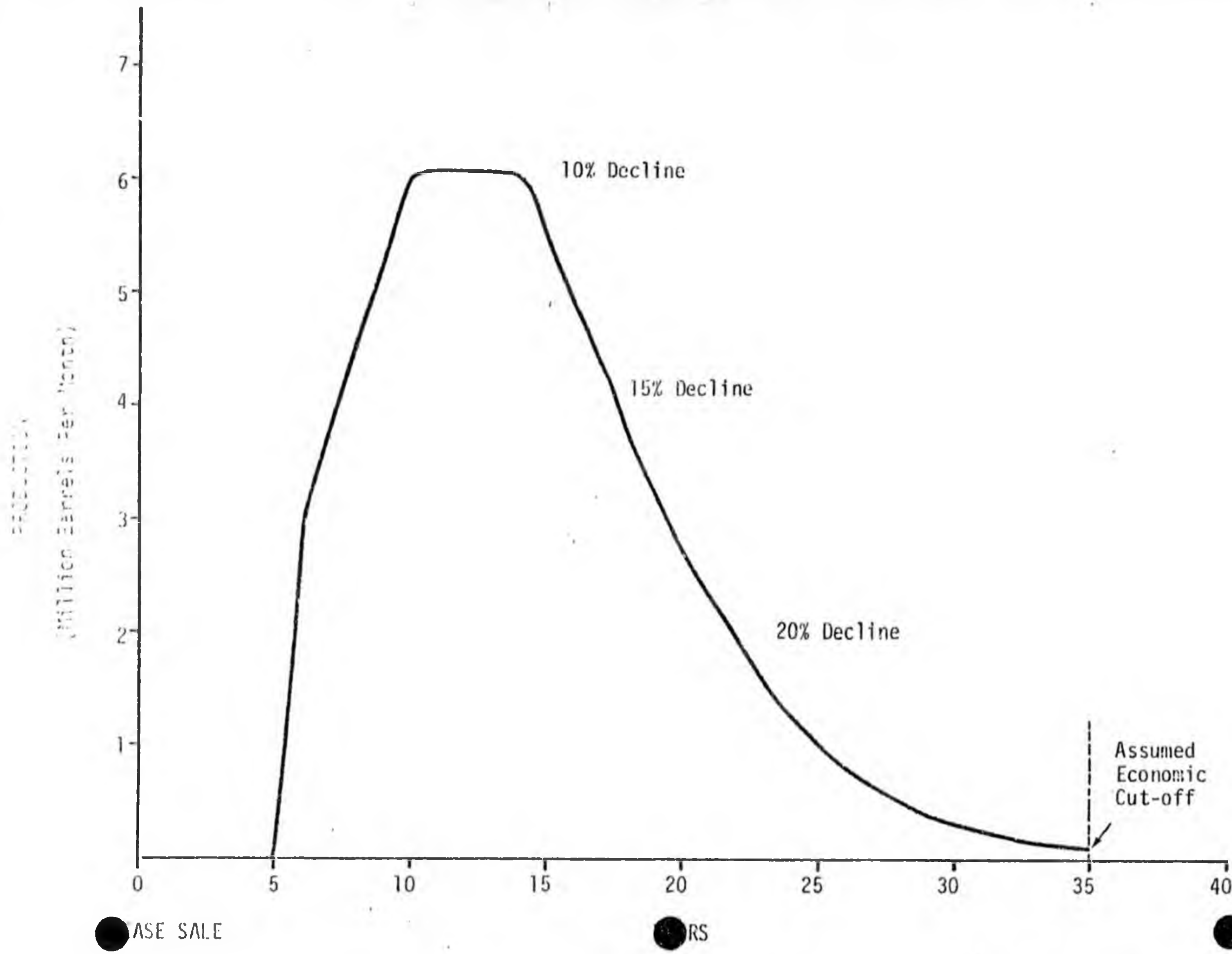


Figure K-6

PRODUCTION HISTORY OF JUPITER OIL FIELD

(Recoverable Reserves 5± Billion Barrels)

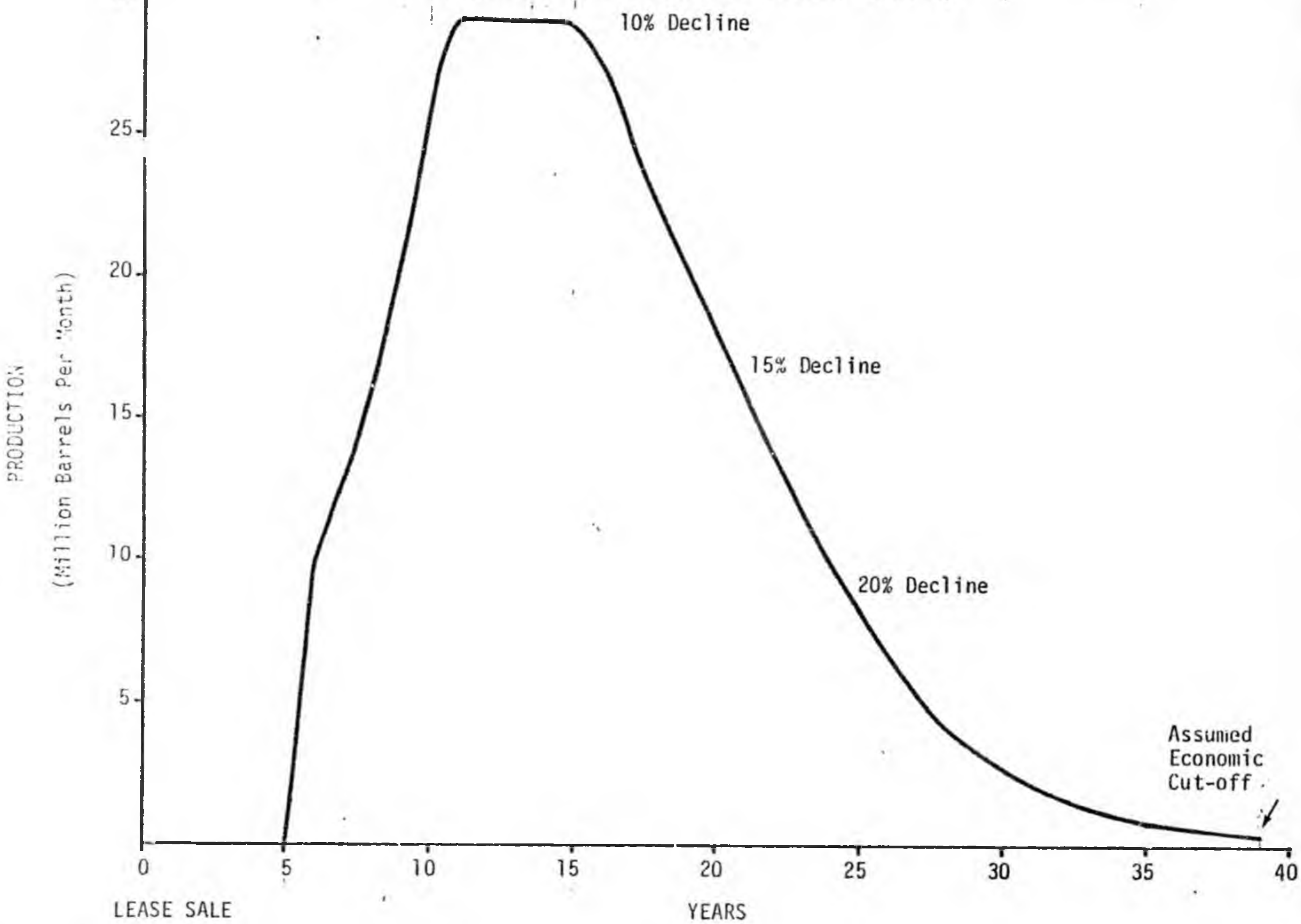
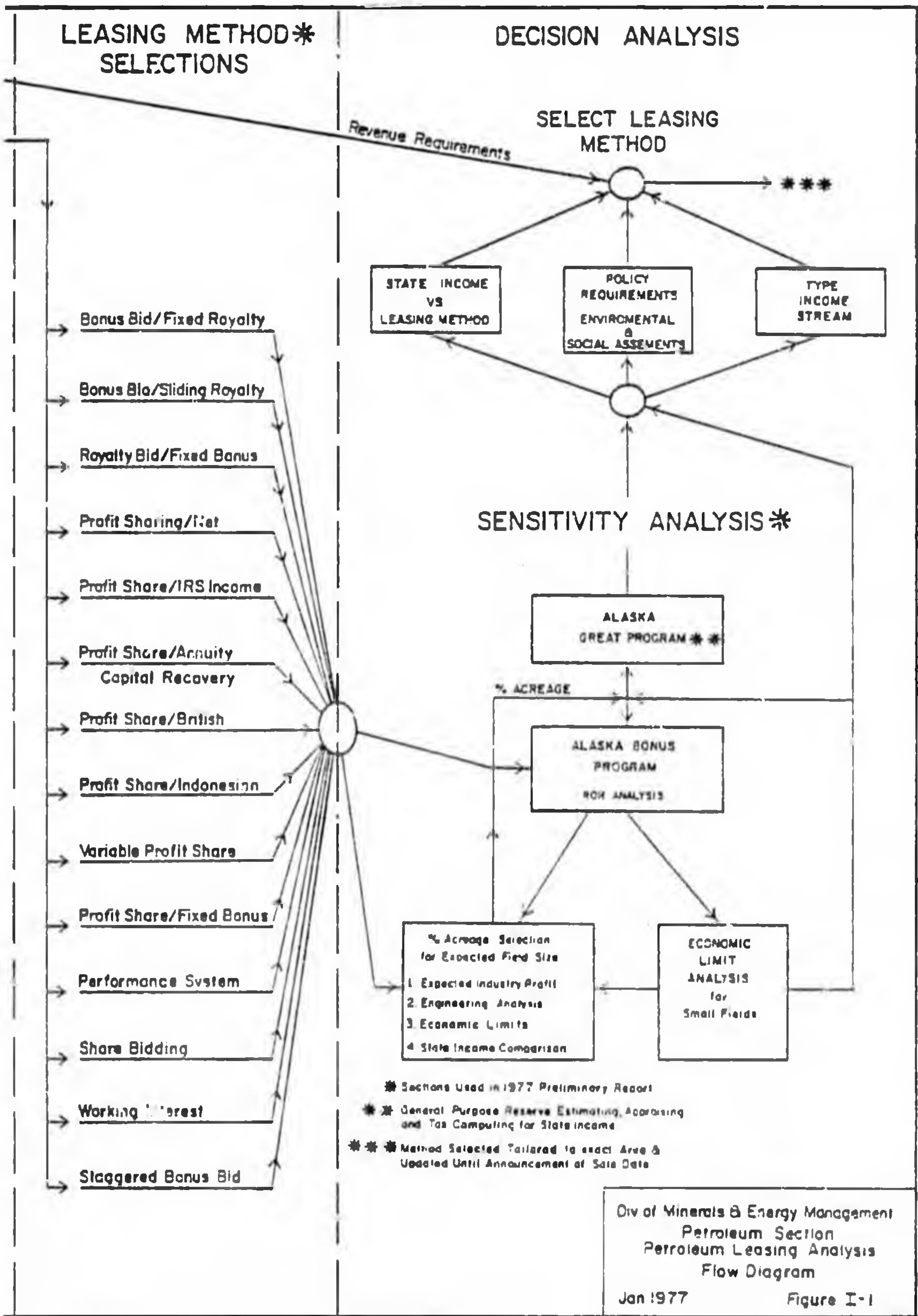


Figure K-7

Sensitivity Analysis - Computer Model System

The section of the Alaska Resource Evaluation and Leasing System that covers the sensitivity of the State's income to the leasing method utilized is described in this appendix. The following chart displays that portion of the general flow diagram that will be covered.



The computer model system employed uses a modern econometric approach designed for an industrial cash flow analysis for a potential venture. Since it is assumed that the State already owns the entire potential field it can approach the problem from a combined average position. In other words, the State will receive income from all the various bidders and can therefore model the entire oil field dealing with only one composite oil company cash flow. The econometric model uses this composite oil company as the test case to determine what incomes and rates of return will result from winning the leases in the sale, then exploring and developing the field.

Because of the unique circumstances surrounding the oil and gas leasing situation in the State of Alaska, it was necessary to have a computer model system developed to fit its needs. Garrett Computing Systems, Inc. of Dallas, Texas refurbished its GREAT system (Generalized Reserve Estimating, Appraising and Tax Computing) to suit these necessary variations and to provide the kind of output the State needed for use in its study of the sensitivity of oil and gas leasing methods.

Two program variations were developed. These programs, the ALASKA BONUS program and the ALASKA GREAT program, are combined into a system which provides an Income to the State of Alaska report as a final product. Figure V-1 shows how the various inputs are incorporated into the ALASKA BONUS program, with the resulting outputs to be used in the ALASKA GREAT program to produce the final report.

Following through this flow diagram in detail, the first decision to be

SENSITIVITY ANALYSIS
COMPUTER MODEL SYSTEM

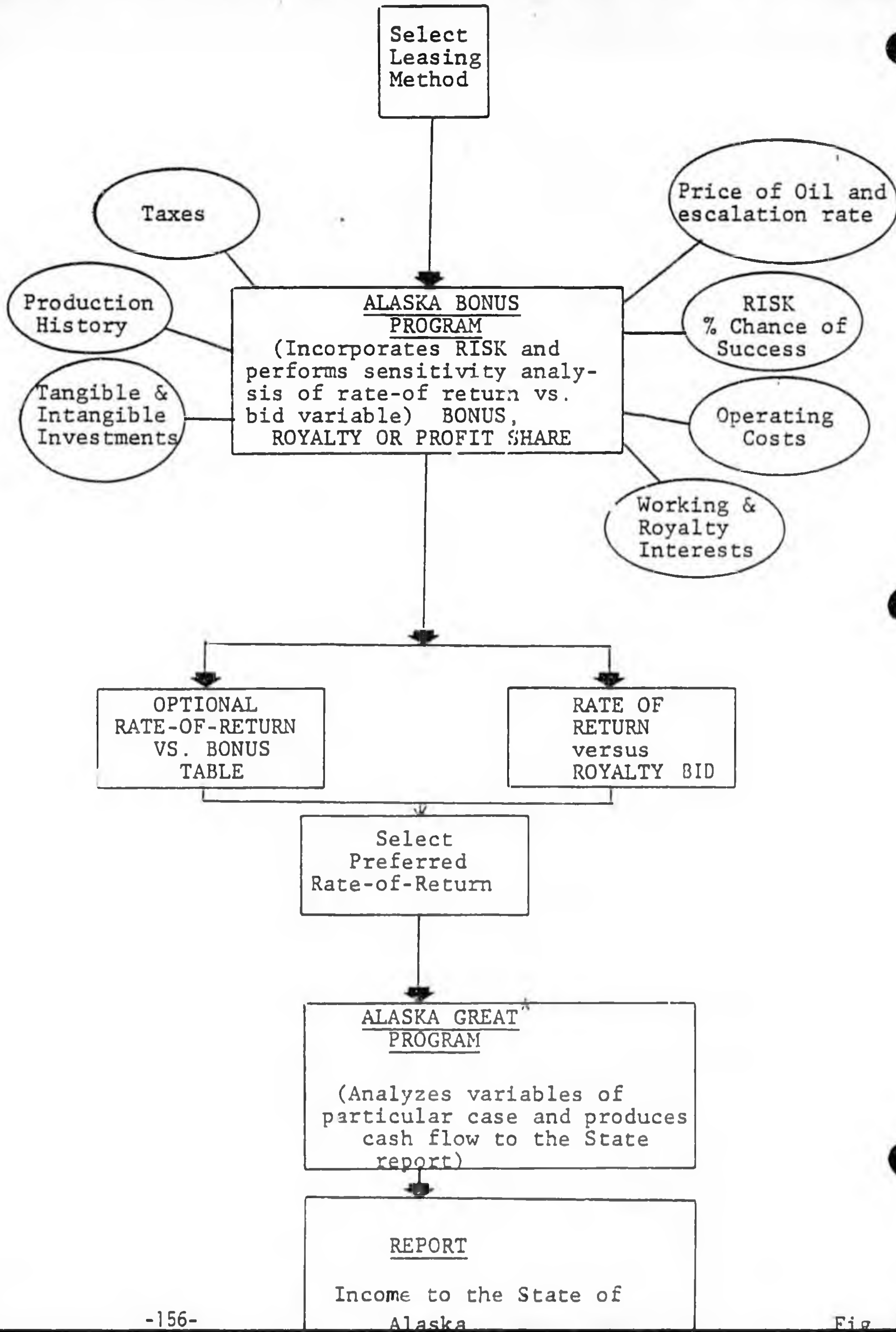


Fig. V-1

made is the choice of a leasing method. The resultant bonuses and/or royalties are used as inputs to the BONUS program along with the other input parameters specified, including taxes, production history, operating costs, price of oil, etc. The ALASKA BONUS program incorporates RISK and performs a sensitivity analysis producing a table of rates of return versus the bonus bid variables. The predetermined rate of return is taken from the table along with its corresponding bonus bid. This bonus bid is used as input to the ALASKA GREAT program which analyzes all of the inputs and produces the finalized report of the Income to the State of Alaska.

ALASKA BONUS PROGRAM

The ALASKA BONUS program is a special computer model used to analyze the cash flow from a lease to the company winning the bid and developing the field. It incorporates risk, entered as the percent chance of success, and performs sensitivity analyses of rate of return versus the bid variable (bonus, royalty, or profit share).

The basic input data to the computer is composed of the investments, expenses, production, prices, etc. of a lease. The investments are designated by type - for example, bonus payment, intangible, exploratory cost, tangible well cost, etc., and by the timing of the investment. Production, expenses and product prices are scheduled for the life of the field. The prices and expenses may be escalated if so desired.

A risk factor is entered into the BONUS program as a percent chance of success. These adjustments for risk are handled as follows:

1) The dry hole/success ratio is calculated as the probability of a success. For a 10 percent chance of success this ratio is 9 (.9/.1), for a 50/50 chance the ratio is 1, etc.

2) Investments such as BONUS and EXPLORATORY are made whether or not the project is a success, and so are equal to the dry hole cost.

3) BONUS type investments are used for the lease bonus. For tax purposes, a bonus is capitalized when made and amortized over the life of production on a units of production basis. If the lease is determined to be non-commercial, the bonus may be written off as a lump sum at that time.

4) EXPL type investments are used for both tangible and intangible exploratory investments. Intangibles are written off when they are made and tangibles are capitalized and depreciated if a success or written off as a lump sum if non-commercial.

5) All other investment types are for those investments made only if the lease is productive.

6) The BONUS version multiplies each BONUS and EXPL type investment by the dry hole/success ratio to arrive at the dry hole cost associated with each success. These costs are then handled as described in 3-4 above.

7) A discounted cash flow analysis is then performed on the composite of the dry hole case with its associated tax treatment and the successful case with its associated tax treatment.

8) If so desired, this model will automatically perform a sensitivity analysis by varying the BONUS and producing a BONUS versus rate of return profile. A plot of a typical BONUS versus rate of return profile is included at the end of this report.

9) Other sensitivity analysis features are available to produce royalty or profit share versus rate of return tables.

THE ALASKA GREAT PROGRAM

The ALASKA version of GREAT is the computer model written by Garrett for the State to analyze the income to be received by the State of Alaska in the form of taxes, royalties, bonuses, profit shares, etc., from the various leasing alternatives. After the BONUS version has been used to determine a likely bid variable (bonus, royalty, or profit share), the case is analyzed by the ALASKA version to produce the cash flow to the State.

The options available allow the analyst to see the cash flow to the State under a variety of conditions such as assuming a success, assuming a dry hole, expected value combining success and failure, etc.

The reports show income to the State by year for each of the following categories:

- -Bonus
- -Royalties and/or Profit Shares
- -Severance Taxes
- -Conservation and Ad Valorem Taxes
- -State Income Taxes
- -Total Income to State

In addition, it shows total gross production, life of production, and the present worth of the cash flow discounted at eight rates from 2 percent to 20 percent. Figure V-2 is an example of the Alaska Great output for an expected value oil field of 600 Million Barrels at 10 percent risk.

INPUTS FOR VARIOUS LEASING METHODS

Several leasing alternatives were explored in this sensitivity analysis, but fewer than had been anticipated due to time constraints. Those methods explored were:

1) Bonus Bid with Fixed Royalty
2) Fixed Bonus with a Royalty Bid
3) Fixed Bonus with Net Profit Share
4) Bonus Bid with Sliding Scale Royalty
5) Percentage of Acreage Withheld Option

Each method had to be dealt with differently within the constraints of the system of programs. In the bonus bid with fixed royalty method, the royalty rate (either 12.5 or 25 percent) is input into the ALASKA BONUS program, which produces the rate of return versus bonus bid table.

VENUS
SOUTH REGION
ONE PCT CHANCE OF SUCCESS
PRICE = $10.56 + 5% TO $13.00
BONUS BID + 12.5% ROYALTY

DATE: 02/02/77
TIME: 12:15CST
FILE: AVENHIT

INCOME TO THE STATE OF ALASKA

AS OF DATE: 12/31/1976

YEAR	NON-TAX REVENUE M$	GROSS TAX SEVERANCE M$	CONSERV+ ADVAL TAX M$	STATE INC. TAX M$	TOTAL INC TO STATE M$
BONUS	173030.				
2	173030.	0.	0.	-4580.	168450.
3	0.	0.	0.	-345.	-345.
4	0.	0.	0.	-26247.	-26247.
5	0.	0.	0.	0.	0.
6	0.	0.	0.	-969.	-969.
7	1922.	1319.	141.	1095.	4477.
8	3450.	2368.	241.	1700.	7759.
9	6230.	4275.	415.	3749.	14670.
10	8490.	5826.	539.	5162.	20017.
11	8914.	6117.	539.	5192.	20762.
S TOT	202036.	19904.	1876.	-15242.	208575.
AFTER	98038.	67275.	5556.	57334.	228203.
TOTAL	300074.	87179.	7432	42092.	436777.

PEAK INCOME
SINGLE PERIOD 2.
5 YRS W/BONUS 2.- 6.
5 YRS WO/BONUS 13.- 17.
LIFE (YEARS) 34.8

GROSS PRODUCTION
OIL (MBBL) 53386.13
GAS (MMCF) 0.
OTHER (MUNITS) 0.

DISC%	PW - M$	DISC%	PW - M$
2.00	362149.032	10.00	210138.872
4.00	307083.700	12.00	191110.736
6.00	265511.910	15.00	169530.964
8.00	234402.472	20.00	145315.032

Figure V-2

A step by step analysis of how the bonus bid with 12.5 percent royalty method is input into the computer follows:

Lines 100 - 107 contain the information for the heading of the report.

```
101 VENUS
102 SOUTH REGION
103 10 PCT CHANCE OF SUCCESS
104 PRICE = $10.86 + 5% TO $18.00
105 BONUS BID + 12.5% ROYALTY
107 BONCOM 10
```

Lines 210 and 220 include the basic information dealing with working interests, royalties, operation costs, initial rates, prices and the chance of success.

```
210 100 12.5 340000 0 0 12 31 1976
220 0 0 0 17.88275 7.9 1
```

Lines 300 through 304 designate a stream of operating costs based on cost per development well per year for the life of the field.

```
300 STREAM -33
301 0 0 0 0 0 0 12150000 15795000
302 18225000 19440000 20655000 21870000 23085000 24300000 25515000 25515000
303 25515000 25515000 25515000 25515000 25515000 25515000 25515000 22680000
304 19845000 16200000 19440000 [illegible] [illegible] 8100000 8100000 4050000
```

Lines 410 through 415 deal with projections of the future reserves and rates of production. The rates of production can be increased or decreased over a fixed period of time based on real production histories.

```
410 CRP 0 0 B/M 5 YRS
411 SET 0 760000 B/M 0 0
412 CPD 0 3830000 B/M 8 YRS
413 CRP 0 3830000 B/M 15 YRS
414 CPD 15 0 B/M 19 YRS
415 CPD 20 0 ELC 0 0
```

The 600 and 700 series is used to modify any data previously entered into the program as constants; such as royalties, operating costs, taxes, increases in oil prices, etc. These values are modified by overlays which replace data originally there; or are escalated, which increments the value of the data entries during a specified period of time.

```
609 10.86 $/B 0 NPT
610 5 PCC 18.00 $
650 0.11725 $/B 0 NPT
710 0 NPI 151285 M$NWI
711 63.438 NPI 0 NPT
```

The 800 series outlines the investment section of the program, scheduling tangible, intangible and salvage values. These investments include exploratory costs, the bonus lease payment, drilling, platform costs, etc.

```
801 BONUS 0 YRS G 0 48186 0
802 EXPL 1 YRS G 1135 4505 0
803 EXPL  2.5 YRS G 2270 9010 0
804 PLATFRM 4.35 YRS G 78546 67427 0
```

The BONUS program reads the input data, makes the necessary adjustments for the risk, and performs an after-tax discounted cash flow analysis. The single output from this program is a bonus versus rate-of-return table.

WHEN BONUS IS 0. M$, ROR = 38.7 PCT.
~~WHEN BONUS IS 7067. M$, ROR = 29.8 PCT.~~
WHEN BONUS IS 17667. M$, ROR = 24.5 PCT.
WHEN BONUS IS 35334. M$, ROR = 19.8 PCT.
~~WHEN BONUS IS 53001. M$, ROR = 17.3 PCT.~~
WHEN BONUS IS 70668. M$, ROR = 15.0 PCT.
WHEN BONUS IS 141336. M$, ROR = 10.3 PCT.
~~WHEN BONUS IS 247333. M$, ROR = 5.9 PCT.~~
WHEN BONUS IS 353340. M$, ROR = 4.4 PCT.
WHEN BONUS IS 459343. M$, ROR = 3.0 PCT.
~~WHEN BONUS IS 565345. M$, ROR = 1.6 PCT.~~
WHEN BONUS IS 706681. M$, ROR = 0. PCT.

The bonus bid which corresponds to the desired pre-determined rate of return can then be selected. This bonus bid is input to the ALASKA GREAT program producing the Income to the State of Alaska report.

In the second leasing method, The Fixed Bonus with a Royalty Bid, the fixed bonus is determined as follows.

Fixed Bonus = 2.5 cents per barrel of expected recoverable oil

The royalty bid is then determined by running a TRACE ROR (rate-of-return) on the BONUS program, which contains a first guess at the royalty percentage. By trial and error, and by using the TRACE ROR, two points can be obtained above and below the desired 18 percent rate-of-return. By interpolation the exact royalty percentage can be found.

The Fixed Bonus with a Net Profit Share method produces the most problems with the computer input. It was first determined that the company must be allowed to recapture the amount of its tangible investment plus 4 percent interest, to give the company some return on its investment. After this amount has been calculated, a TRACE ROR is run to compute the Net Profit Interest at an 18 percent rate of return to the oil company. (This trace is done within the BONUS program).

Next, a TRACE A is run on the ALASKA GREAT program to trace line 44 or the "Net Profit Stream." A list is provided of thirty-two values which tell at what time the investment plus 4 percent interest will be recaptured and when the state will begin to get its percentage of profit share. It is necessary to put a "0" in the royalty slot on line 210.

The net profit stream from the TRACE A is input on lines 305 through 309 into the ALASKA GREAT program, producing the income to the state of Alaska. Of course, the fixed bonus in this method is determined in the same way as it is paired with the Royalty Bid.

The fourth leasing alternative, the Bonus Bid with a sliding scale royalty is handled in a slightly different manner. It was determined that approximately five percent increments gave an adequate representation of a sliding scale royalty. These royalty increments are input on line 183. Lines 181 and 182 denote barrels of available oil, and barrels to be added to each step of the royalty up the scale. For example, a 20 percent royalty of production over 1,000,000 barrels added to a base figure of 200,000 Bbls would be the royalty in this case. Therefore the royalty is a function of the production of the oil field.

The final leasing method dealt with is the Percentage of Acreage Withheld Option. In this method, the entire area under consideration is divided into tracts with 40 percent withheld for sale at a later date. Sixty percent of the tracts are sold at a 10 percent risk, and are input to the computer as such. The remaining tracts are sold two years later, so all of the time limits of production and investments must be increased by two years. Also a 90 percent risk factor is used at this later date. The resultant incomes from these two runs are added together to give the total income to the State of Alaska.

The major economic factors are calculated by the ALASKA BONUS program and the ALASKA GREAT program in this fashion:

Production*= Field Size x Risk Factor

$$\text{Total Bonus Amount} = \frac{\text{Bonus per Structure}}{\text{Risk Factor}}$$

$$\text{Total Dry Hole Cost} = \frac{\text{Dry hole costs per Structure}}{\text{Risk Factor}}$$

Gross Revenue = Expected Production x Crude Oil Price

Severance Tax = Gross Revenue x .079

Royalty Value = (Gross Revenue - Severance Tax) x Royalty Fraction

Revenue to Oil Company = Gross Revenue - Severance Tax

Conservation and Advalorem Tax = Gross Production x .1175¢/Barrel

Operating Cost = Wells per year x Fixed value depending on Field Size

State Income Tax = (Oil Co. Revenue - Operating Cost - Depreciated Tangible Investment - Amortized Bonus - C & A Tax) x .094

Fed Income Tax less Investment Tax Credit = (Oil Co. Rev - Operating Cost - Depreci te tangible Investment - Amortized Bonus - C & A Tax - State Income Tax x .48

Profit = Oil Co. Revenue - Bonus - Investment - Operating Cost - C& A Tax - State Income Tax - FIT

State Income = Bonus + Severance Tax + Royalty + C & A Tax + State Income Tax

*In this study production is called "Expected Value Production."

APPENDIX C

COST, PRICE AND EXPECTED VALUE

The approach used in this report is to approximate actual conditions expected wherever possible. To accomplish this a considerable effort was used to determine what the possible future prices of oil could be and what operating costs might occur on State lands. We have selected only one price method for our sensitivity study although we realize that there may be considerable uncertainty in future Alaskan prices and costs. In an actual resource management analysis we will be using a probabilistic input for costs and prices and a Monte Carlo sampling technique for the economic calculations to account for this uncertainty. The price and cost approach we have used appears to be quite adequate for showing the sensitivity of income to leasing methods.

PRICE

A great deal of uncertainty surrounds FEA pricing of new oil. Therefore, for purposes of this study, the price used in the low price case has been either the current upper tier price in Cook Inlet, or the expected price to be received at Prudhoe Bay as published in the Oil and Gas Journal. In the high price case the world price of OPEC oil adjusted for transportation costs was used. These prices were escalated by 5% per year to a maximum of $18.00 per barrel with the expectation that the OPEC countries will raise the real price of oil each year by at least this percentage and that the FEA will allow the real price of oil to rise at this rate. This price approach is probably conservative since real price increases in the value of petroleum in the next thirty years may be spectacular.

COST

Because very little has been published on costs of petroleum production or investment costs in the State of Alaska, the costs used in this study were predicted on the best estimate available. To assist in this estimate, cost parameters from the Cornell University study (Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf), and from special studies published by the American Petroleum Institute were used, among others.

In addition to the costs of operating a field and its associated investment costs for platforms, production facilities, exploratory and development wells; a rate for Federal and state income tax, Alaska severance tax, ad valorem tax, and conservation tax was included.

Due to the inconsistency of income received from Alaska corporation income tax due to the provision for apportionment, the scenarios are based on the operations of a domestic oil company. By using this approach all companies are placed on the same tax basis.

Ad valorem tax and conservation tax is computed on a per barrel basis. The study "Analysis of the Profitability of Operations in the Cook Inlet Basin by the Oil and Gas Industry, Taken as a Whole" prepared by the Department of Revenue, was used to estimate ad valorem tax on a per barrel basis.

Operating costs were based on a cost per well since operating costs follow closely increased development, and decline with well shut ins. Operating costs include lifting costs and remedial well work.

The most commonly used method of computing depreciation of equipment on producing oil properties is the "unit-of-production" method, and this method was used in this study. The distinguishing feature of this method is that depreciation per unit is obtained by dividing the estimated units of hydrocarbon reserve into the investment in equipment. The number of barrels produced in a given period is multiplied by the depreciation per unit to obtain the amount of depreciation for the period.

So far as this study is concerned, the situation in which the operator has the full working interest and there are no other outstanding interests except the basic royalty or net profit interest was the only one considered.

For purposes of computing Federal income tax, the oil company was allowed a 10% investment tax credit, which is in line with current tax procedure.

All costs, such as geological and geophysical costs, are considered "sunk" at the time of lease sale, and are given no consideration in investment costs of the project. Sunk costs and the costs of borrowing money are considered, though, when choosing a rate-of-return equitable to the oil company. The Cornell study also considered prior costs to be "sunk" at the time of lease sale. Price and cost regions (Figure C1) are discussed in Section IV of the report.

Expected Value

The expected value concept was used throughout this study as a method of uniting uncertainty and economic factors into a meaningful decision criterion. For any course of action there are at least one and often many possible outcomes.

COST REGIONS

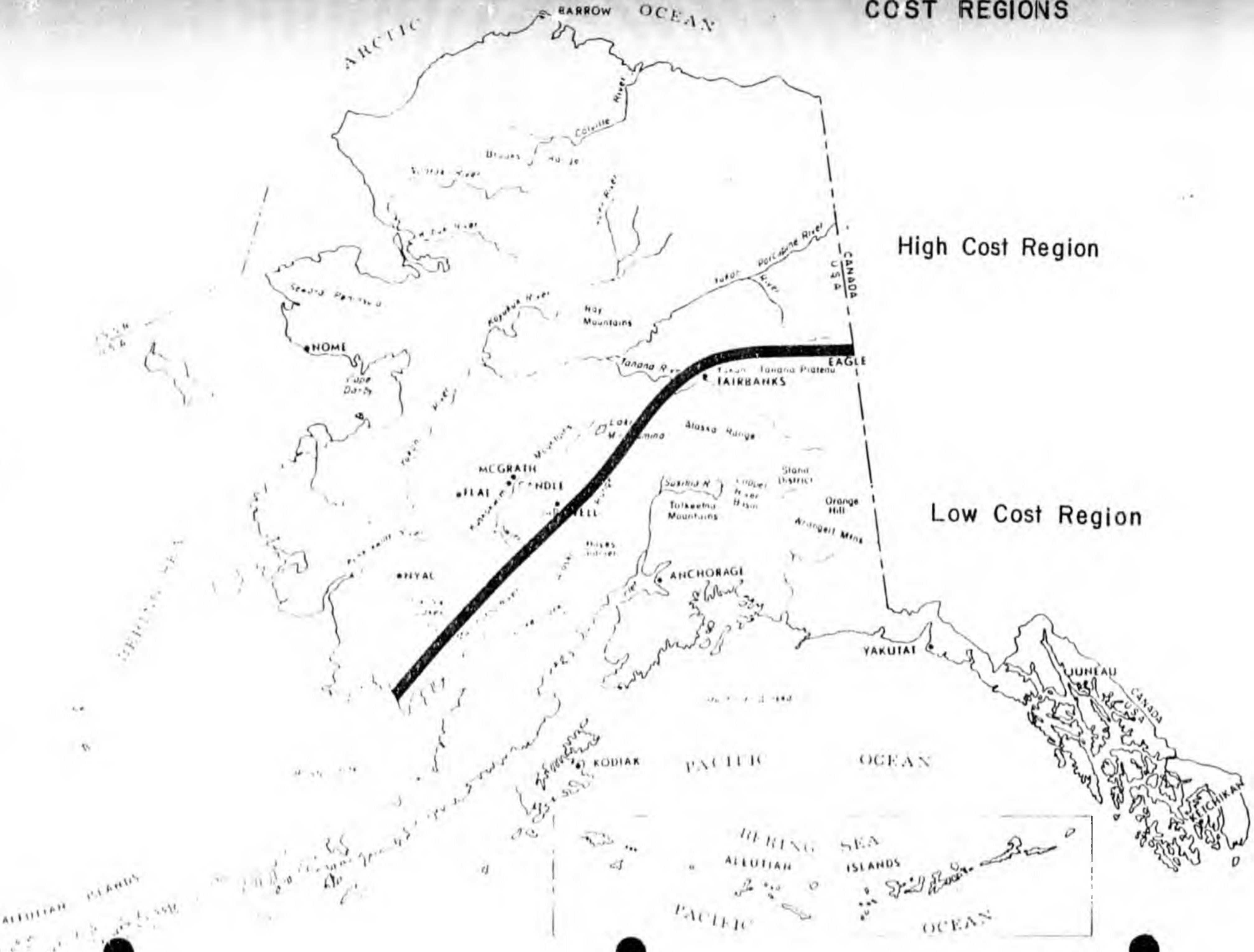


FIGURE C-1

The probabilities of each of these possible outcomes, each expressed as a fraction from 0 to 1.0, must sum to 1.0. If an event has a certain outcome then that outcome has a probability of 1.0 If an event has multiple possible outcomes, such as the flip of a fair coin, the sum of the probabilities of occurrence must equal 1.0, e.g. probability of heads (0.5) plus probability of tails (0.5) equals 1.0.

The expected value of an outcome is defined as the value received if that outcome occurs times the likelihood of its occurrence. The expected value of a course of action is the sum of the expected values of its possible outcome. For example, if nine dry structures are drilled for each discovery drilled, the probability of a discovery for any specific structure is one in ten or 10%. This then means that the average oil recovery for each of the ten structures drilled is 10 percent of the productive structure. Suppose additional information on the field was obtained, causing some structures not to be drilled because of low probability of an economical size field. It would then be likely that the probability of occurrence would increase (due to better information) as would the expected value. Let's say that with the new information, only four dry structures are drilled for each discovery drilled. This results in the expected value of recoverable oil to increase from 10 percent to 20 percent. Therefore, based on this information, for each field leased, the cash bonus bid to the State should be increased in direct proportion to the increase in the probability of the expected event occurring.

In business and economic decision making, a major decision criterion is often expected monetary value or EMV. For instance, assume that the president of the company has two alternative courses of action for a proposed investment. The first alternative has a 50/50 chance of either losing $100,000 or making

$1,000,000 thus its EMV = (.5)(-100,000)+(.5)(1,000,000)= -50,000 + 500,000 = $450,000. Alternative two has a 30 percent chance of losing $100,000 and a 70 percent chance of making $700,000, with an EMV of (.3)(-100,000) + (.7)(700,000) = -30,000 + 490,000 = $460,000. Therefore, if the company president based his decision on EMV, he would select alternative number two. Of course, there may be other overriding considerations but strictly from the standpoint of maximizing EMV, alternative two is superior.

In this analysis, the monetary value was most often represented by cash flows and their discounted values rather than simple lump sum values.

Currently, the State of Alaska's leasing system is a cash bonus bid with a minimum fixed royalty of 12.5 percent. The methods analyzed in this report include the present system with different fixed royalties, sliding scale royalty with bonus bid, net profit share bid with fixed bonus, royalty bid with fixed bonus and percentage of acreage withheld. This limited number of methods were chosen for analysis from a great number of possible methods due to time limitation factors. In the future The Division of Minerals and Energy Management plans to analyze a number of other methods possibly including fixed bonus with oil payment bidding, performance system, share bidding, working interest system, staggered bonus bidding, profit share with an IRS income base, annuity capital recovery profit share, British-type profit share, Indonesian production sharing, variable profit share, fixed bonus with profit share bidding. The basic elements of these methods are summarized below after a discussion of the methods utilized in this study. If a more detailed description of these methods is desired, please refer to Federal Leasing of Petroleum on the Outer Continental Shelf or Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf (see bibliography).

EXAMINATION OF METHODS USED IN THIS STUDY

(1) Bonus Bid With Fixed Royalty

Bonus bid with fixed royalty is the system currently used by the State of Alaska. In a lease sale, the winning bid for a tract is the one which makes the highest sealed cash bonus bid. There is also a minimum royalty of 12.5 percent. An advantage of this system is that government receives revenue regardless if there are economical quantities of oil or gas found and/or produced. However, bonus bids are depressed to account for risk. An inherent difficulty is that royalty affects income but not cost. For evaluation purposes, we have used two different fixed royalty rates: our current rate of 12.5% and an increased rate of 25%. To avoid early termination of production, royalties need to be flexible during a field's declining years.

(2) Sliding Scale Royalty With Bonus Bid

Under this system, the government receives a cash bonus bid and a sliding scale royalty. We used 12.5% as a minimum figure and 60% as a ceiling wherein the rate in any period is dependent upon the production of that period. If the production rate is high, then a higher royalty rate is applied. This encourages production to continue in order to extend the field's economic limit. The royalty rate falls as production declines. Greater flexibility in setting the initial rate is the major advantage of this system while not running the risk of an uneconomically (for Industry) high royalty rate. On the other hand, to achieve an overall lower royalty payment, a company might spread out production over a longer period of time. Usually, however, because of the time value of money and increased operating costs, oil companies generally try to accelerate production.

(3) Net Profit Share Bid With Fixed Bonus

The fixed bonus in this report was calculated by multiplying 2.5 cents per barrel times estimated recoverable reserves. This small fixed bonus is required as earnest money. The bonus is low enough to encourage producers to bid a high net profit share while permitting profitable development. In this system, the operator recovers all of the capital investment plus 4% nominal interest per year before the government takes its share of the profit.

(4) Royalty Bid With Fixed Bonus

This system utilizes the same method to calculate fixed bonus as described for Net Profit Share. The bid parameter is a function of production instead of net profits. Since the bonus is fixed, interested parties bid on the royalty rate that the government is to receive. The advantage of royalty bidding is that little front end money is needed by Industry. However, this would encourage speculation causing an overbid. Royalty bidding should encourage more conpetition among bidders and may allow the smaller companies a better chance of winning the tract.

(5) Percentage of Acreage Withheld Option

This option should be considered for use in any high risk bidding situation, except for small fields. As its title implies, a percentage of the acreage is withheld from the initial lease sale situation. Analysis has shown that the lessor can derive significantly higher incomes by withholding a percentage of a petroleum structure for a deferred sale. The percentage to be withheld would be determined from geologic/geophysical data and economic analysis on the prospective structure.

Refer to the analysis section for further discussion of these methods.

POSSIBLE METHODS FOR FUTURE ANALYSIS

(1) Fixed Bonus With Oil Payment Bidding

A fixed bonus is specified in dollars whereas the oil payment can be designated as a percent of production or as a set number or barrels to be paid for each year of the lease. The primary advantage is that both government and private industry share the market price risk of petroleum. However, if the oil payment percentage of production, then this method is actually royalty bidding. Moreover, if the payment is in terms of barrels paid per year, then the system is actually a rental system. Both royalty and rental systems have their advantages and disadvantages so there is not a unique advantage to having an oil payment bidding system.

(2) Performance System

This system, which has been used by Canada and Great Britain, replaces the competitive market place with administrative evaluations. The government, as the authorized leasing agent, itemizes the performance criteria such as the rate and amount of work to be performed on each tract, and the amount of capital expenditures. The performance system provides government with the authority to specify the exact rate and extent of resource development. This allows for stringent control over the use of the resources. Another advantage of this system is that it may give small operators greater access to the resources.

(3) Share Bidding or Phillips Plan

The entire structure is leased in this system. Bonus bids are entered for the entire field instead of for a specific tract. Based on their equity in the field, each company receives a percent of the profits or losses with a maximum of 20 percent participation by any one company. The companies form a corporation with each company having the same percentage of control as they have equity. One operator is responsible for exploration and development. Bonus bids held in escrow may be used for field development costs. The advantage of this system is that the bonus bids are used as working capital to explore and develop the field. However, the administrative complexity of such a plan necessitates close government monitoring of the corporations' activities. This monitoring increases administrative costs to the government, but in return the government acquires detailed knowledge of operation economics.

(4) Working Interest

In this system, the companies bid for working interest shares of the structure rather than for a specific tract. The winning bidders are those whose bids sum to the largest total bid for the entire area. The lessor selects an operator to undertake exploration and development of the area after the lease sale. The economics of this system are similar to the profit share or royalty systems. The difference is that this system allows for more than one owner of the structure since it is likely that there will be several winning bidders.

(5) Staggered Bonus Bidding

The bonus is not paid in one lump sum, but in several stages. For instance, paying at the time of sale, when petroleum is found and when production begins. The primary advantage of this system is that there is less capital expended at the front end, thereby allowing more funds for exploration and development.

(6) Profit Share Systems

Profit share systems consist of a variable cash bonus bid plus profit sharing taken on net income. Since there are a number of ways to define net income, there are also a number of profit sharing systems. In these profit sharing systems there is no allowance for loss sharing if no development occurs. The remainder of the leasing methods will be some variation of profit sharing.

(A) Profit Share System With an IRS Income Base

The IRS income base is defined as gross revenue minus operating costs and depreciation. This definition is essentially net operating revenue in each year allowing for the depreciation of capital investment. One advantage of this system is that since costs are deducted before the profit share is taken, it reduces the possibility of early termination of production.

(B) Annuity Capital Recovery Profit Share System

The annuity, with a pre-specified interest rate and length of capital recovery period, is derived from all of the capital investment plus interest to the time production begins. To obtain the profit share base, the amount of the annuity is subtracted from net operating profits. After the investment capital has been recovered, the government profit share is taken from the net operating profit. The profit share rate can generally be set high since the profit share base approximates a true economic share. The problem of no development occurring because the profit share rate was set too high has been alleviated by this system.

(C) British Type Profit Share System

In this system, the government does not take its profit share until after some factor times the total capital investment is recovered from net profits. Otherwise, the economics are the same as the annuity capital recovery system except that the investment capital is recovered sooner and over a shorter time interval.

(D) Indonesian Production Sharing System

All capital equipment becomes government property in this system. However, a rental rate of up to 10% per year is allowed to be added to operating costs. Each year operating cost can be deducted from forty percent of production. If operating costs exceed forty percent, they can be carried forward to the following year. The profit share is then taken from the remaining sixty percent. This system is more appropriately called a constrained profit system, since total recoverable costs cannot exceed forty percent of the value of production. There is no provision in this system for return on initial investment capital in the profit share basis.

(E) Variable Profit Share System

Variable profit share is similar to the sliding scale royalty system with the exception that the variation in profit share rate is expressed in terms of annual net profits rather than annual production. This system could be used with any of the profit share systems described thus far. There is the advantage in this system of more flexibility in setting the rate before reserves and costs are known than in fixed rate system. Production may be spread over a longer time period to achieve a lower profit sharing rate.

(F) Fixed Bonus With Profit Share Bidding System

The bonus is fixed in this system and interested parties bid on the profit share that the government is to receive. This system encourages speculation, however, and to what degree, can only be evaluated in conjunction with the type of profit share base being used.

COMBINATIONS

Of the leasing methods just discussed, it is apparent that some of the methods can be combined to give a large possible number of leasing alternatives. Combinations will not be examined individually because inferences can be drawn from the basic alternatives previously described.

SECTION IV

THE VARIATION OF PETROLEUM LEASING CRITERIA WITH GEOGRAPHIC LOCATION

SUMMARY

Limited data was available for this study and many subjective decisions were used during the analysis. Even within the limited scope of this work it is apparent that areas of the state can be divided into different leasing classifications for oil and gas. An on-going resource/economic analysis of resource areas by the Division of Minerals and Energy Management will insure refinement of this classification system and an optimum cost/benefit leasing program.

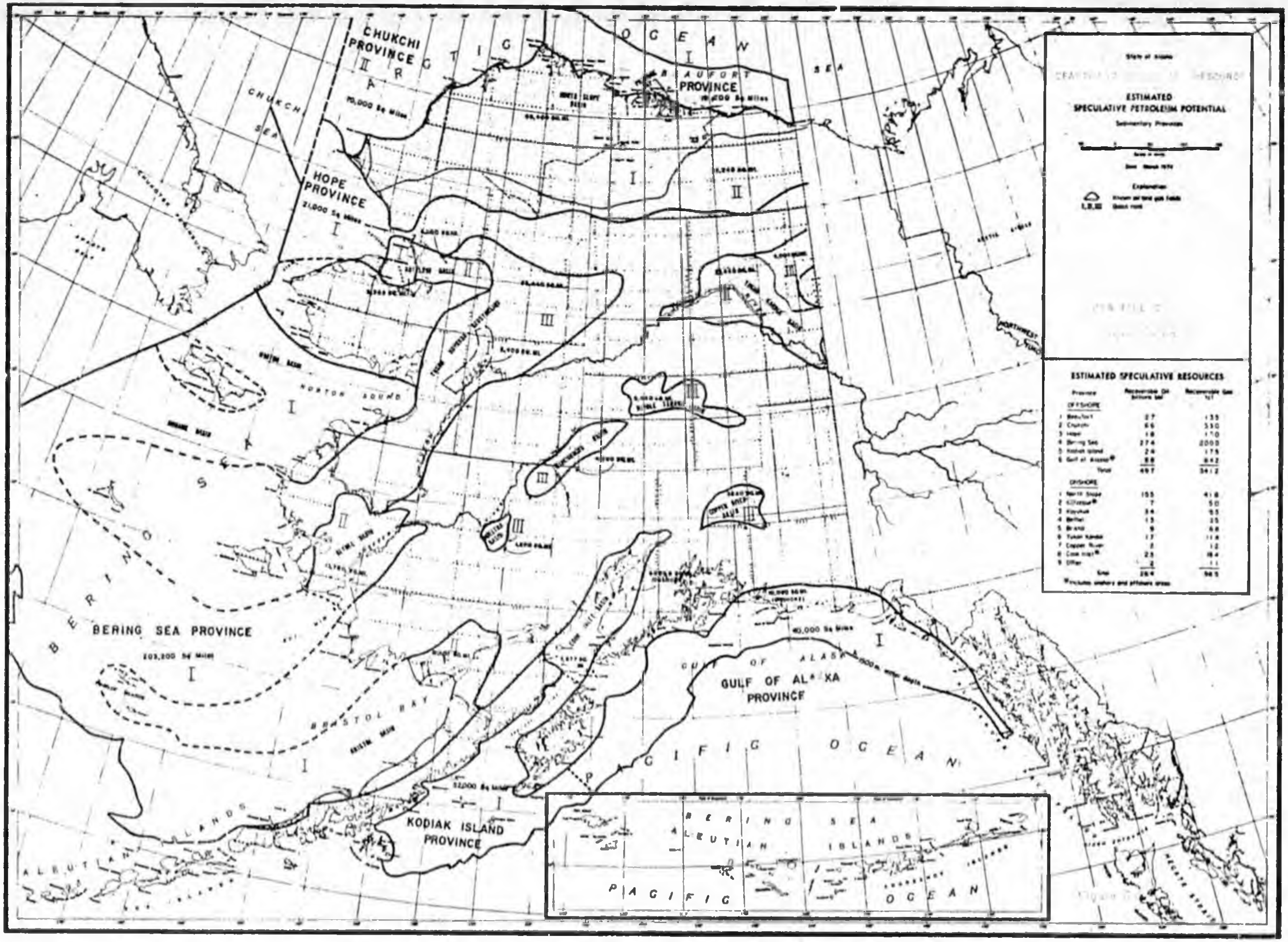
The lessons learned here and the technical abilities developed can be used for determining the cost/benefit of leasing other Energy and Minerals. Coal and Uranium would both fall easily into this type of analysis. Uranium is leased everywhere in the United States but Alaska on a royalty per pound basis. Up to now no economic/cost benefit attempt has been made to establish what the optimum price would be for leasing coal and uranium. Some coal leases have been let for 10¢ a ton on twenty year contracts. The application of an analysis similar to the one used for petroleum to other resources would be the first step to ENERGY Resource Management.

SECTION IV

The State of Alaska is unique in its position as a potential national source of petroleum and its derivatives. The vast area to be developed along with the explorative immaturity of the state provides many variables which can change with time. In this report, these variables will be examined and some conclusions will be drawn as to the potentials of oil and gas resources on state lands in Alaska, and the possibility of state leasing sales to be held in the future.

The analysis "Sensitivity of State Income to Various Leasing Methods" revealed four key variables with respect to oil and gas leasing. (1) The amount of the expected petroleum resources, (2) the risk of finding these reserves, (3) cost of operations and (4) the price of petroleum. This study indicates that all four of these variables are dependent upon their geographic locations in Alaska. Since income to the State from oil and gas development is therefore dependent upon a knowledge of the resource and regional characteristics, flexible leasing methods will be necessary if income to the state is to be maximized.

We have found that the state can be divided into regions based on the key leasing criteria. These Resource/Risk/Cost/Price provinces can be used when considering leasing methods and would establish the type of input variables for economic resource analysis before leasing.



CHUKCHI PROVINCE
70,000 Sq Miles
BEAUFORT PROVINCE
HOPE PROVINCE
21,000 Sq Miles
NORTON SOUND
BERING SEA PROVINCE
BRISTOL BAY
GULF OF ALASKA PROVINCE
KODIAK ISLAND PROVINCE
PACIFIC OCEAN
BERING SEA
ALEUTIAN ISLANDS
State of Alaska
ESTIMATED
SPECULATIVE PETROLEUM POTENTIAL
Sedimentary Provinces
Explanation
ESTIMATED SPECULATIVE RESOURCES
OFFSHORE
ONSHORE
Total

Potential Oil & Gas Regions on State Lands

The potential of the state oil and gas lands has been calculated from the Division of Geological and Geophysical Survey's Open File Report 50 (Figure G-1) which outlines basin by basin estimates of recoverable oil and gas resources in Alaska. As this report states, these state land calculations are subject to a high degree of error, given the lack of information and exploration data in some of these areas. The information available to the state at this time for evaluation of petroleum resource 's limited but the Division of Minerals and Energy Management in its long range analysis of petroleum potential for leasing will acquire seismic and other data in the future to adequately evaluate each state province. There is a possibility of large oil fields in some of the more promising sedimentary basins which might make these estimates too low, but there is also the possibility of no fields or very small fields in some of the state held areas which could make the estimates too high.

As previously stated, Alaska's sedimentary basins are relatively unexplored. The variability in the amount of explorative data is great, ranging from the exhaustively explored areas of the Upper Cook Inlet and Prudhoe Bay to the Western Chukchi and Norton Sound Provinces which have never been drilled. The amount of hydrocarbons in these areas is a highly speculative question, and future information will surely modify the resource picture of the State of Alaska.

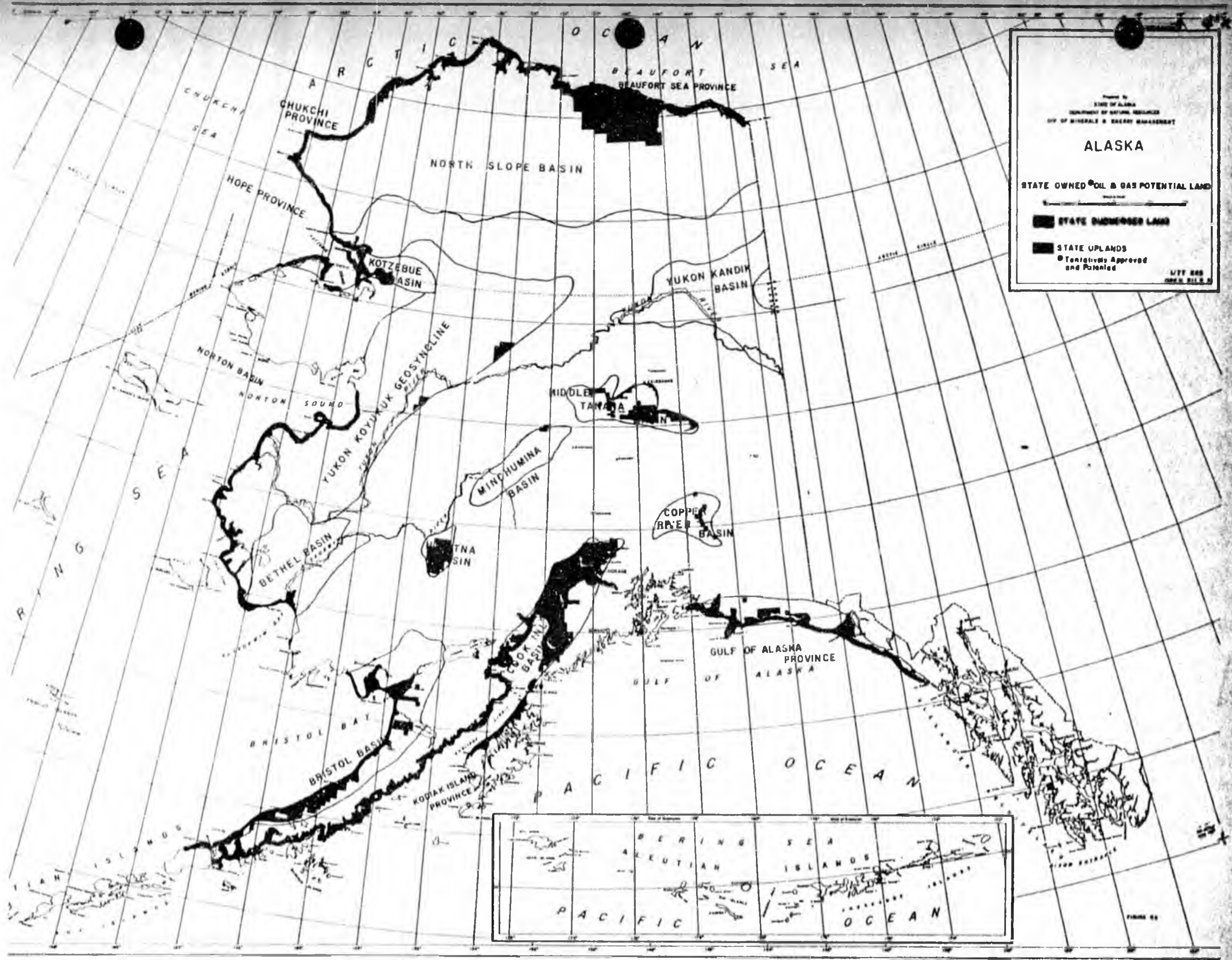
Both patented and tentatively approved state lands lie within the onshore oil basins in Alaska (Figure G-2). The onshore lands are generally not too high in petroleum potential, with the exception of those on the North Slope and in Bristol Basin. Generally, interior areas have a greater potential for gas than oil.

The State owns or has tentative approval on a large amount of promising land in the Bristol Bay - Alaska Peninsula region, the North Slope, and on the Kenai peninsula in Lower Cook Inlet. At this time, these lands appear to have potential for both oil and gas and would be relatively low in cost of production, owing to existing transportation systems.

In addition to its onshore lands, the State owns coastal waters to a limit of three miles from state shorelines (Figure G-2) The three mile limit submerged lands provide the state with some good petroleum potential areas notably in the Gulf of Alaska, Cook Inlet, Bristol Bay and Beaufort Sea regions. As Federal OCS leasing progresses and offshore discoveries are made, the three mile limit submerged lands will need to be seriously considered for leasing.

In this section we have outlined the potential recoverable oil and gas reserves on state lands including those within Alaska's three mile limit. Their potential will be discussed in the light that future exploration data will change these estimates.

Because of this degree of variability, it is necessary to look at the State in different sections, or leasing provinces. Each leasing province contains different risk and cost parameters, as well as more or less potential for oil reserves. Figure G-1 has shown the location of these provinces,



ALASKA
STATE OWNED OIL & GAS POTENTIAL LAND
STATE SUBMERGED LAND
STATE UPLANDS
Tentatively Approved and Patented
ARCTIC OCEAN
BEAUFORT SEA
BEAUFORT SEA PROVINCE
CHUKCHI SEA
CHUKCHI PROVINCE
NORTH SLOPE BASIN
HOPE PROVINCE
KOTZEBUE BASIN
YUKON KANDIK BASIN
NORTON BASIN
NORTON SOUND
YUKON KOYUKUK GEOSYNCLINE
MIDDLE TANANA BASIN
MINCHUMINA BASIN
COPPER RIVER BASIN
BETHEL BASIN
COOK INLET BASIN
GULF OF ALASKA PROVINCE
GULF OF ALASKA
BRISTOL BAY
BRISTOL BASIN
KODIAK ISLAND PROVINCE
PACIFIC OCEAN
BERING SEA
ALEUTIAN ISLANDS

Table G-1 gives an estimate of their geographic size and a speculative assessment of the possible oil & gas reserves to be expected. A province by province discussion is given in Appendix A.

Table G-1
PETROLEUM POTENTIAL AREAS AND
ESTIMATED QUANTITIES ON STATE LANDS

GEOLOGIC BASIN OR PROVINCE	SQ. MILES ONSHORE	SQ. MILES OFFSHORE	OIL POTENTIAL	AMOUNT OF OIL LOW (MMB)	AMOUNT OF OIL HIGH (MMB)	O-G RATIO	AMOUNT OF GAS LOW (TCF)	AMOUNT OF GAS HIGH (TCF)	PERCENT RELIABILITY
Gulf of Alaska	630	3,308	I	0	354.4	6.1	0	2,161.84	30
Cook Inlet	1,116	1,188	I	163.0	325.0	6.1	992	1,983.0	30
Bristol Basin & Ak Peninsula	2,088	3,132	I	323.5	647.9	6.1	1,976.1	3,952.19	30
Bering Sea			I	0	Unknown*		0	Unknown*	
(Norton Basin)		972							
(Bethel Offshore)		506							
(Yukon-Koyukuk)		612							
Hope Basin		468	I	0	Marginal		0	Marginal	
North Slope Uplands	6,624		I	<1,260.0	>1,260.0	2.7	<3,402.0	>3,402.0	50
Beaufort Sea		2,160	I	300.0	Unknown**		1,500.0	Unknown**	
Chukchi Sea		1,440	I	0	Unknown*		0	Unknown*	
Kotzebue Province		864	II	30.1	115.0	6.1	187.0	716.0	30
Kodiak Island		800	III	0	Marginal		0	Unknown*	
Hollitna Basin	1,260		III	0	Marginal		0	Marginal	
Minchumina	144		III	0	Unknown*		0	Unknown*	
Copper River	342		III	0	Marginal	6.1	0	146.1	25
Middle Tanana	1,980		III	0	Unknown*		0	Unknown*	
Yukon-Koyukuk (Onshore)	540		III	0	Marginal		0	Unknown*	
Total State Land	14,724	14,110							

*Not enough explorative information is available in this region to make an estimate of potential resource quantities.
**Large reserves possible, but not enough explorative information available.

LEASING CRITERIA

Price

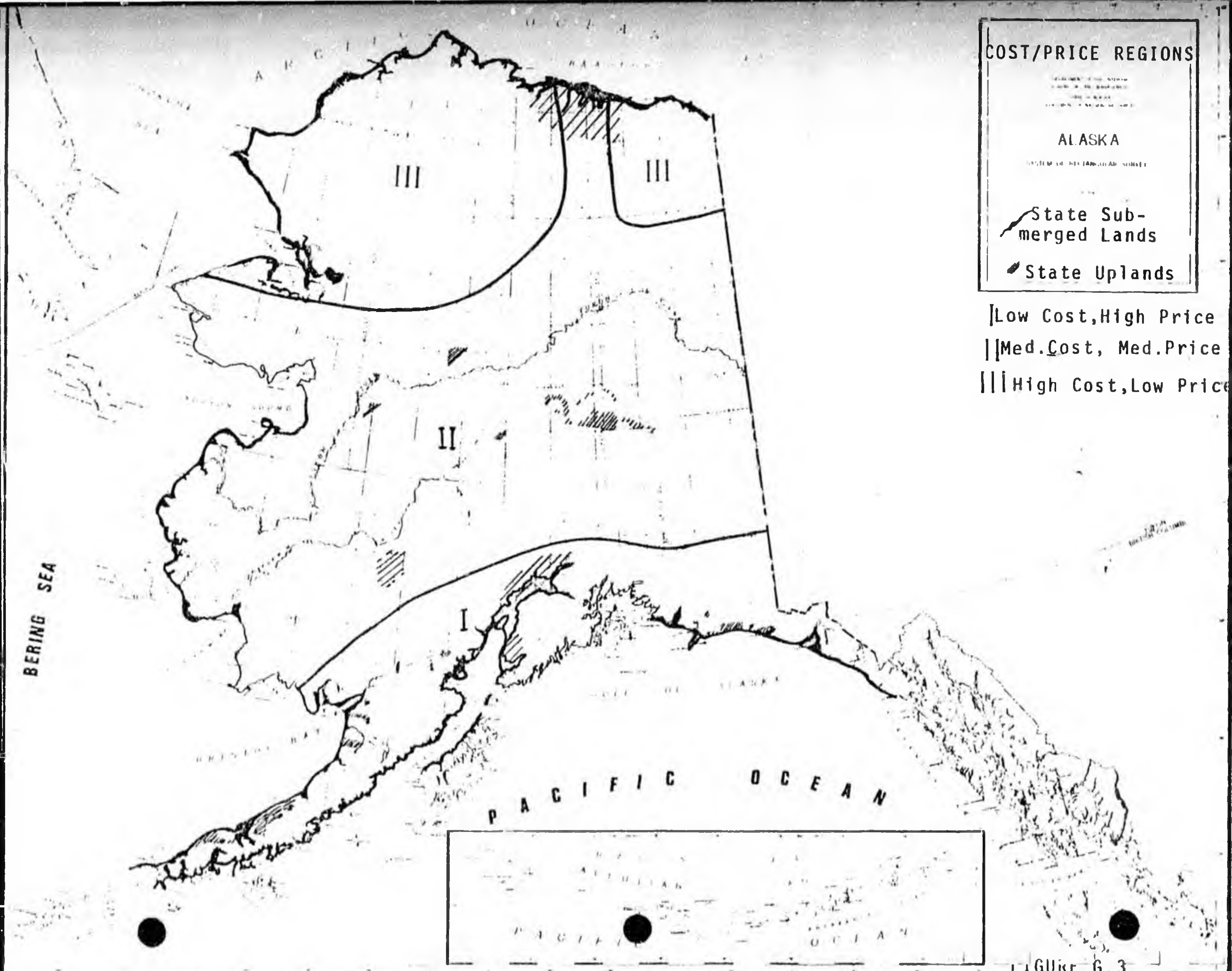
Well head price difference within the State for new Alaskan petroleum is primarily a function of the cost of transporting the crude to market. In this initial study we have simply chosen price regions based on the availability and cost of transportation. These regions were chosen subjectively and will be refined when our studies on transportation and development costs are completed. Figure G-3 show a rough Price-Cost region breakdown for the State. Three pricing criteria that can be used are:

1. Low Well Head Price: High pipeline cost, difficult tanker movement, long distances.
2. Medium Well Head Price: Less than number 1.
3. High Well Head Price: Ice free areas, near Coast, cheaper pipelines, shorter distances.

Cost

In this report, the State of Alaska has been divided into three cost regions (Figure G-3). These cost determinations have been based on location, existing transportation, (pipelines, etc.), navigability of adjacent waters (ice free ports all year or not), cost and availability of labor, materials, and location near population centers. What all of these factors have in common is location. The more remote the petroleum potential area, the higher the cost. These cost parameters are outlined below:

1. Low Cost: Near to existing transportation system, close to population center, lower labor and material cost, southern location.
2. Medium Cost: Middle-Alaska location, possible extensions to existing pipeline systems, feasibility of roadways, etc.


COST/PRICE REGIONS
ALASKA
State Submerged Lands
State Uplands
I Low Cost, High Price
II Med. Cost, Med. Price
III High Cost, Low Price
III
III
II
I
BERING SEA
PACIFIC OCEAN
FIGURE G. 3

3. High Cost: Remote, northern location. Difficult transportation (no ice-free ports or existing pipeline systems), high labor and material costs, no existing social infrastructure.

Risk

For our purposes, risk is a function of the exploration maturity of a petroleum potential area, and the degree of confidence that oil or gas will be discovered. In general, the less exploratory information available in a petroleum region, the higher the risk factor. To outline the leasing criteria in this study, we have estimated the level of public knowledge, as well as the overall potential for oil and gas resources within an area. When selecting a leasing method for a particular sale, the degree of confidence factor would be a major consideration.

1. Low Risk: Good potential for either oil or gas, previous discoveries within the region under discussion, a high level of exploration maturity.
2. Medium Risk: Medium to good potential for oil or gas, no previous discoveries in the area, and/or moderate knowledge level of the region through explorative methods. (Seismic work, etc.)
3. High Risk: Poor oil or gas potential, exploration maturity level is low, and no previous oil or gas discoveries in area or closely located regions.

Table G-3 groups the geographic petroleum provinces by exploration maturity (Risk) and cost region. The largest number of provinces lie in the high risk category and this is indicative of the lack of exploratory information available in the central and northern provinces of the state. Only the Upper Cook Inlet and Prudhoe Bay areas can be classified as mature enough to assign a Low Risk type leasing method analysis. Ideally, areas should not be selected for leasing in a high risk category. Since this will not always be possible because of outside influences such as OCS development, lack of drilling date, etc., analysis for leasing procedure will have to be done using arbitrary decisions and tables such as these.

The important factor to recognize is that the various petroleum potential areas of the state are each different with respect to the key leasing parameters. Each province must be approached on an individual basis and leased with a method that fits its unique status. Once the decision has been reached to consider leasing, a detailed risk analysis of the expected value petroleum features would need to be undertaken. As shown in the economic analysis of leasing methods, it is to the advantage of the state to always attempt to decrease the risk before actual leasing, and a decrease in risk can be achieved by insuring that there is as much public knowledge of the petroleum potential area as possible. Flexibility, public knowledge, and analysis are absolute prerequisites for optimum cost benefit resource development.

Table G-3 - Rough Estimates of Risk by Cost Region

I - Southern Provinces and Basins

Low cost and high price parameters

High Risk	Med Risk	Low Risk
Kodiak Island	Gulf of Alaska Lower Cook Inlet Bristol Basin and Alaska Peninsula	Upper Cook Inlet

II - Middle Alaska Provinces and Basins

Medium Cost and high price parameters

High Risk	Med Risk	Low Risk
Bering Sea (Norton) Bering Sea (Yukon-Koyukuk) Yukon-Koyukuk Geosyncline Bering Sea (Bethel Basin)		

III - Northern Provinces and Basins

High cost and high cost parameters

High Risk	Med Risk	Low Risk
Kotzebue Province Hope Province Chukchi Province Middle Tanana Minchumina Copper River Hollitna	North Slope Beaufort Sea Province	Prudhoe Bay Area

PETROLEUM POTENTIAL AREAS AND CORRESPONDING LEASING CRITERIA

The various leasing criteria can be combined to give the leasing character of each resource province. These approximate classifications can then be used for planning future leasing and in the economic analysis for selection of an optimum leasing method. Referring to Figure G-2 which shows the various leasing provinces, Table G-2 lists each of these provinces along with its corresponding leasing characteristics.

Table G-2 can be utilized for the establishment of priorties on exploratory data acquisition and as a preliminary tool for long range lease planning. As the table is refined, it will be used as a classifications input for a leasing method analysis.

Table G-2 - Petroleum Potential Areas and Corresponding Leasing Criteria

Petroleum Province or Basin	Price*	Risk*	Cost*
Gulf of Alaska	High	Med	Low
Upper Cook Inlet	High	Low	Low
Lower Cook Inlet	High	Med	Low
Kodiak Island	High	High	Low
Bristol Basin	High	Med	Low
Bering Sea (Norton)	Med	High	Med
Bering Sea (Yukon-Koyukuk)	Med	High	Med
Bering Sea (Bethel Basin)	Med	High	Med
Yukon-Koyukuk Geosyncline	Med	High	Med
Kotzebue Province	Low	High	High
Hope Province	Low	High	High
Chukchi Province	Low	High	High
North Slope Uplands	Low	Med-High	High
Prudhoe Bay Area	Low	Low-Med	Med
Beaufort Province	Low	Med-High	High
Middle Tanana, Minchumina, Copper River, Hollitna	Med	Med-High	Med

*Note - All classifications can change with time and further knowledge.

STATE LAND WITH PETROLEUM POTENTIAL

BY

PROVINCE

Following is a description of each potential area, both onshore and offshore, including estimates of their petroleum potential.

GULF OF ALASKA

Figure G-4

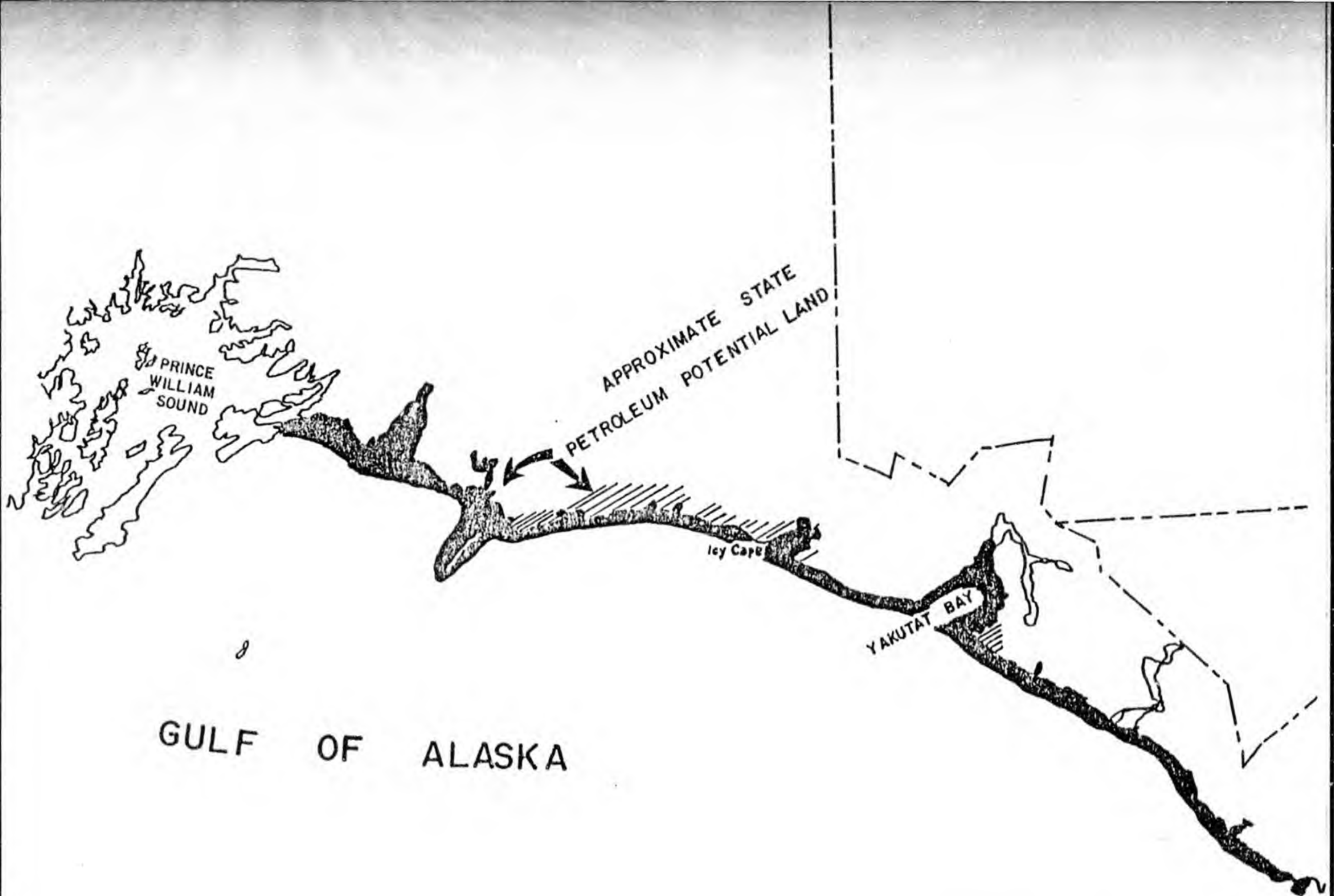
The State submerged lands in the Gulf of Alaska could contain a few small petroleum fields or one large field, or perhaps, God forbid, nothing but salt water. Both onshore and offshore statelands which lie in the Gulf of Alaska total approximately 3,940 square miles. The average thickness of the sedimentary deposits in this area is about 1.8 miles, making the available amount of sediments about 7,088 cubic miles. A low to high estimate of petroleum reserves ranges from zero to 354 million barrels. Gas reserves could range from zero to 2,000 TCF.

COOK INLET BASIN (LOWER & UPPER COOK INLET)

Figure G-5

It is becoming increasingly apparent that the Upper Cook Inlet Basin has been developed near the economic limit of its resources and capacity, and that future oil and gas discoveries will lie further south.

The estimate of recoverable oil and gas in offshore areas has been lowered as more exhaustive exploration has yielded fewer discoveries than previously expected. Also, the remaining state owned areas to be explored lie on the fringes of the Cook Inlet basin, where oil and gas potential may not be as high as in the middle portion of the basin Because of this, the estimate of 115,000 bbls/cubic mile in Alaska Open File 50 has been dropped to 50,000 bbls/cubic mile, to serve as a more realistic bottom line figure for



GULF OF ALASKA PROVINCE

FIGURE G-4

recoverable oil and gas resources on remaining state submerged lands.

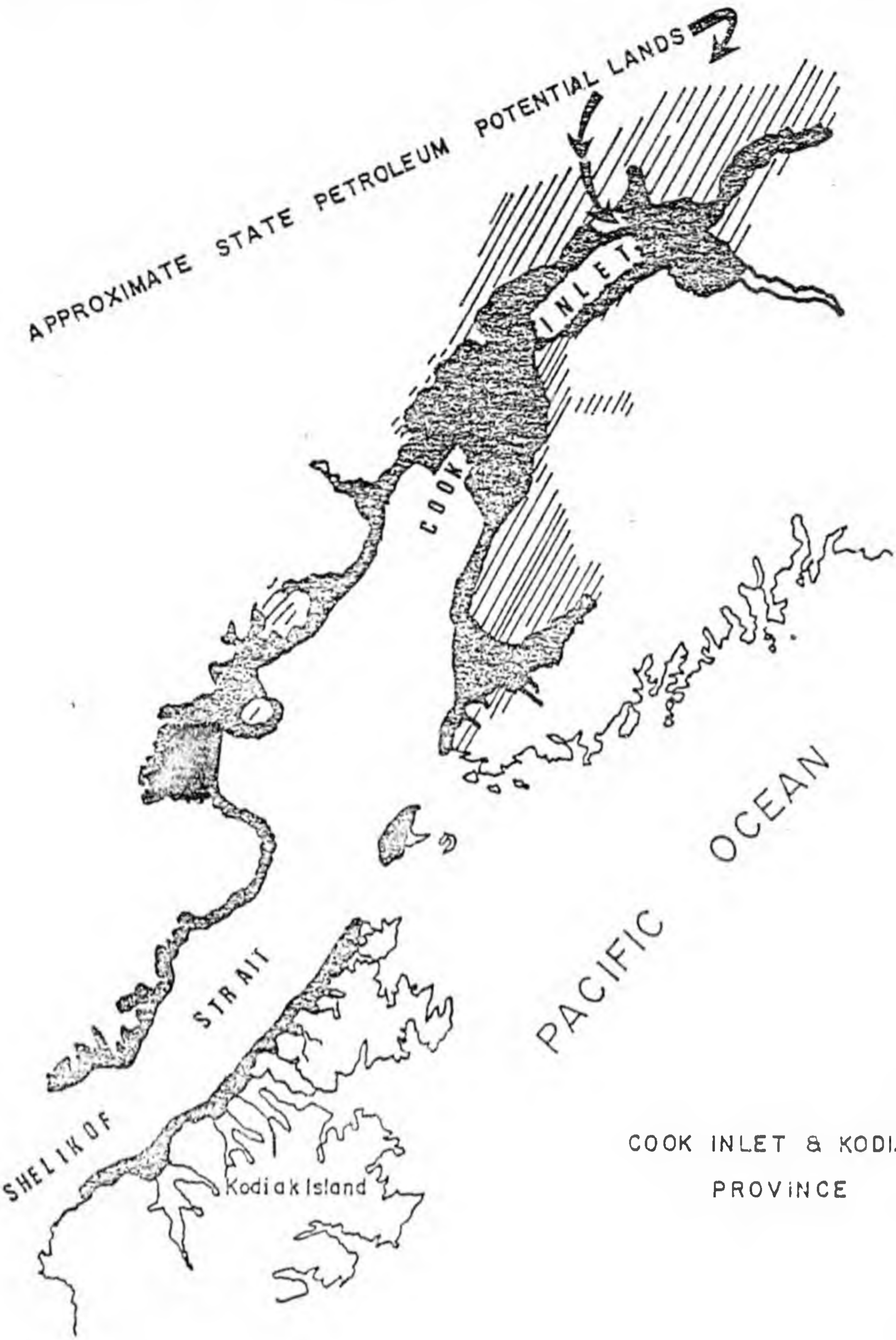
Onshore areas of the Upper Cook Inlet contain a large amount of both patented and tentatively approved state lands. These lands were believed to be of high petroleum potential, but exploration in the northern onshore areas has not been as successful as anticipated. Therefore, the estimation in this area also has been scaled down to 25,000 bbls/cubic mile.

KODIAK ISLAND

Figure G-5

The State owns very little petroleum potential land in the Kodiak Island province. The three mile limit area around Kodiak Island is at the edge of the petroleum province and the speculative estimated petroleum resources are low.

Approximately 4,000 square miles of petroleum potential lands are in this province. Because of the poor petroleum potential of this area, and its location at the edge of the petroleum basin, we estimate the quantity of available hydrocarbons in this region to be from zero to marginal. Our outlook for possible economic recovery of resources is pessimistic.



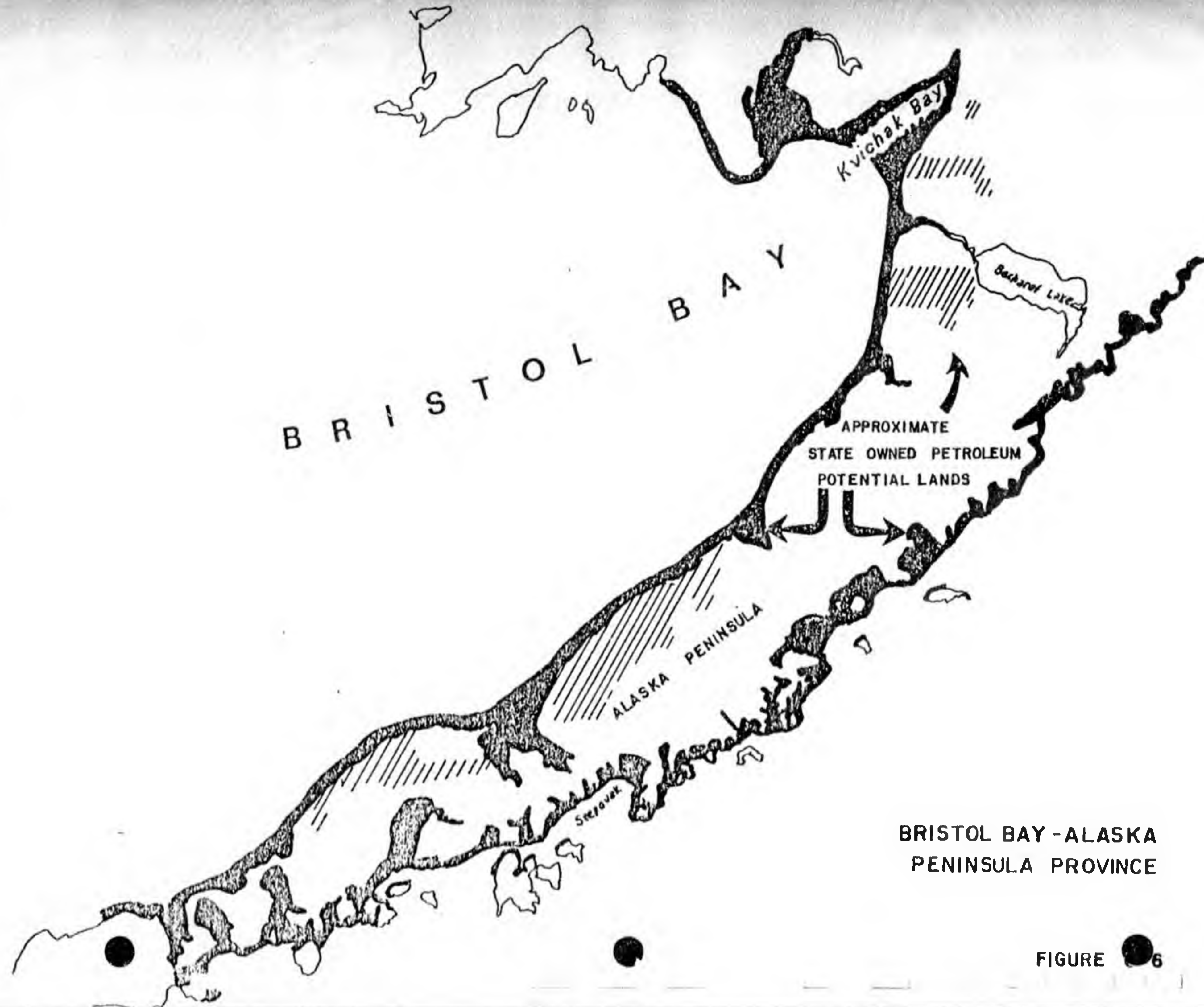
COOK INLET & KODIAK ISLAND
PROVINCE

FIGURE G-5

BRISTOL BASIN & THE ALASKA PENINSULA

Figure G-6

Presently the Bristol Bay Basin and the Alaska Peninsula are two of the more promising areas in Alaska for future reserves of petroleum. Although exploration efforts have revealed no commercial quantities of petroleum to date, drilling operations continue. In time we should know more about this area and its potential for hydrocarbon deposits, but for now the amount of estimated speculative recoverable petroleum ranges from 300 MMB to 650 MMB. Of course, this could lie in small deposits or in one large petroleum reserve. Speculative potential natural gas on state owned land averages 29.65 TCF.



BRISTOL BAY - ALASKA
PENINSULA PROVINCE

FIGURE 6

BERING SEA (Bethel Offshore)
(Yukon-Koyukuk Offshore)
(Norton Basin)

Figure G-7

State owned lands of the Bering Sea petroleum potential basins are geologically complex, and the chance of finding giant oil and gas fields is small. The fields are more likely to be small and scattered; however, the cumulative reserves in these fields could be potentially economic. Future OCS development may lead to discoveries in the state submerged lands.

There are no onshore state lands adjacent to the Bering Sea provinces under discussion. The petroleum potential of coastal submerged lands of the Yukon-Koyukuk Basin (612 Sq. miles), the Bethel Basin (506 sq. miles), and the Norton Sound (972 sq. miles) is relatively unknown. The development of OCS acreages and onshore native activity will provide information in the future. Seismic data will also be needed for evaluation of these state lands.

MINCHUMINA, HOLLITNA, LOWER TANANA, COPPER RIVER, AND THE YUKON-KOYUKUK GEOSYNCLINE

There has been very little state land selected in the interior petroleum basins. As indicated in Open File 50, the majority of state land selections to date in interior Alaska have been in the hard mineral highland areas. Only a few miles of state selections appear on the fringes of the lowland petroleum basins (See Figure G-2). An estimate of the petroleum potential in these scattered lands is not possible with the limited data available to the state at this time. Hopefully, the state will be able to select

BERING SEA PROVINCES

FIGURE G-7

additional lowlands in the future. The Division of Minerals and Energy Management will need to evaluate the interior lands as conditions permit.

KOTZEBUE PROVINCE

Figure G-8

Onshore and offshore areas of the Kotzebue Province are in a potential petroleum area, and future exploration could lead to discoveries. State petroleum potential lands total approximately 864 square miles in this area, all lying offshore or located in Selawick Lake. Very little drilling has occurred in this region, with only two dry holes drilled on land to date, but generally these state submerged lands lie in the thicker sedimentary portions of the petroleum basin than the areas where the unsuccessful tests were made.

As in the case of the Bering Sea petroleum areas, future OCS and native development may give us more information on this area. Seismic data will also give a clearer picture of petroleum potential.

HOPE PROVINCE

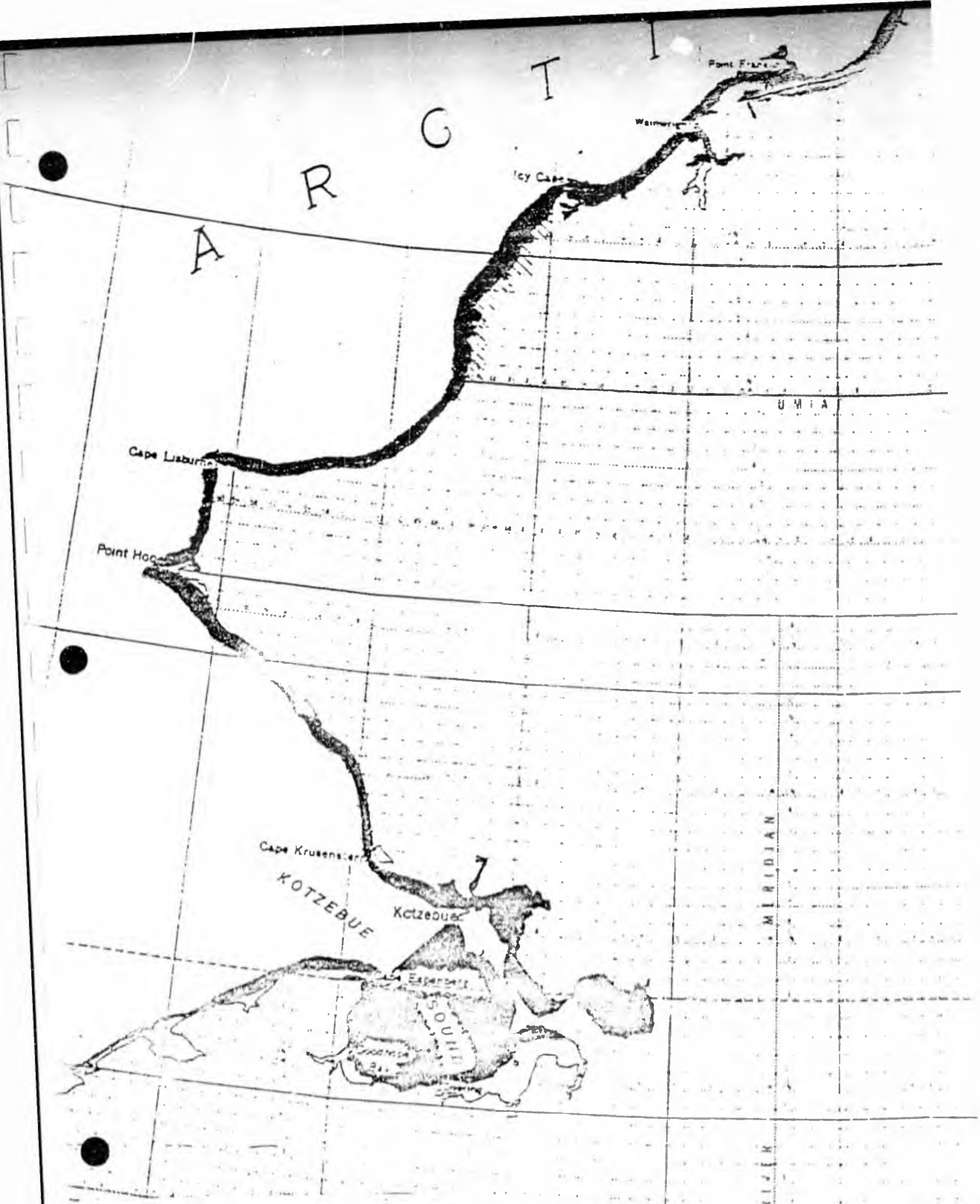
Figure G-8

State lands contained within the Hope Province consist of about 450 square miles along the coastline of the lower Chukchi Sea. It is difficult to speculate on amounts of recoverable oil and gas in the Hope Province because of the small amount of public exploratory work which has been done to date, but on the basis of available information, the state owned lands do not appear to be very promising. Estimates of potential reserves will have to be made in the future after sufficient data becomes available.

CHUKCHI PROVINCE

Figure G-8

The oil and gas potential of the Chukchi Province is highly speculative



Kotzebue Province
Hope Province
Chukchi Province

Figure G-8

due to the lack of seismic and explorative data in this area. The state-owned lands contained within the Chukchi Province are all submerged, three mile limit lands. When more information is available we should have a better picture of the hydrocarbon potential of the entire Chukchi region.

State owned submerged lands in the Chukchi total about 1,440 square miles.

NORTH SLOPE REGION

Figure G-9

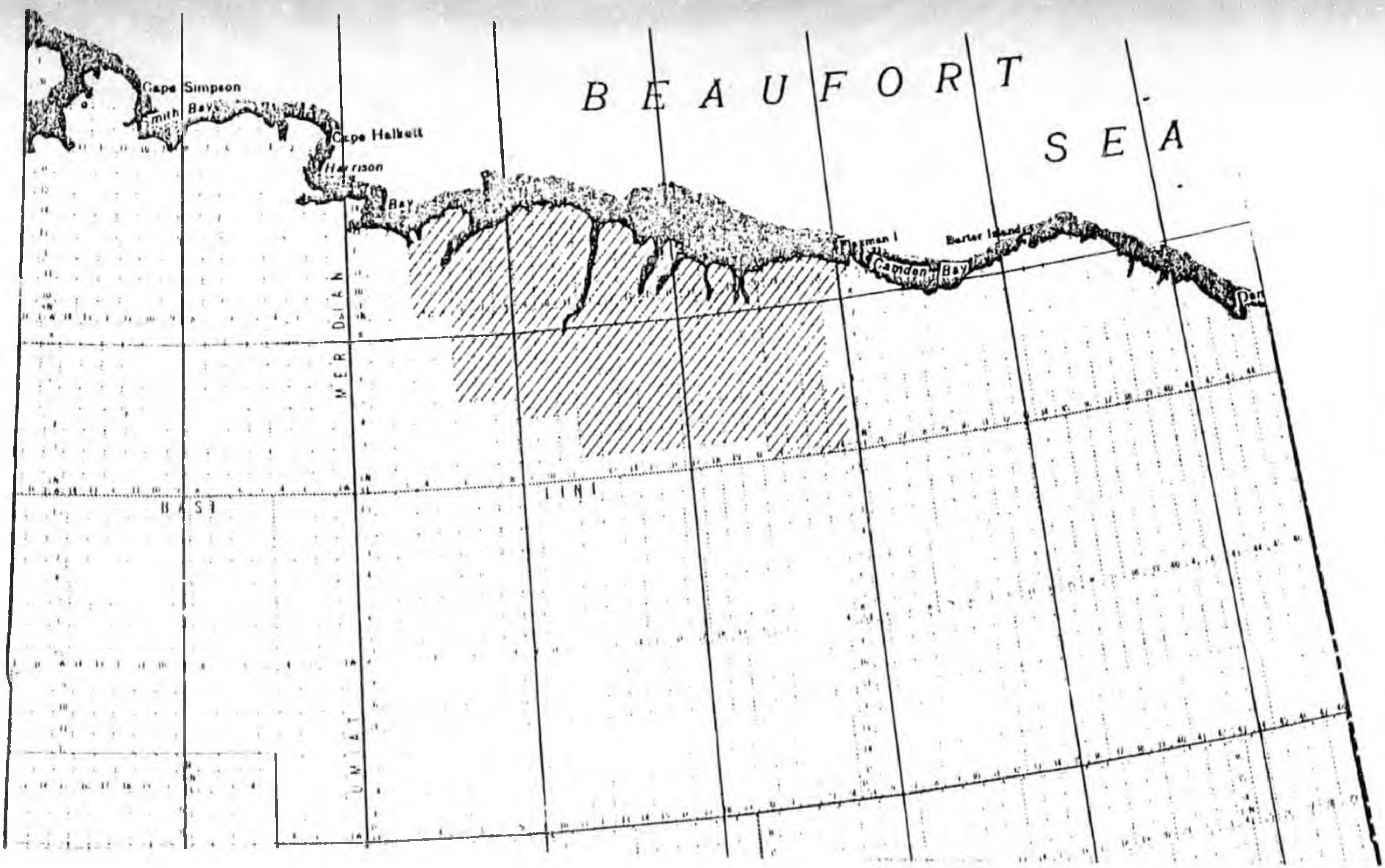
State owned uplands of the North Slope are shown on Figure G-10. These lands have been under active industry exploration for a number of years and contain the Prudhoe Bay giant petroleum field. The potential for additional oil is high here and a rough estimate of remaining reserves would be as follows:

There are approximately 6,624 square miles of state lands contained within the North Slope uplands. This total is about ten percent of the entire number I potential lands on the Slope. Taking ten percent of the potential recoverable reserve figure in Open File 50, there are about 1,200 MMB of recoverable oil reserves, and 3,400 TCF of natural gas. These are middle estimates, and real recovery could be more or less than these reserve figures. Seismic data is needed to map the structures in these state uplands.

BEAUFORT PROVINCE

Because of the proximity of the Beaufort Sea area to the Prudhoe Bay discovery, and its geological similarities to Prudhoe Bay, the Beaufort Sea region is high on the list of state areas available to oil and gas leasing. There are about 2,160 square miles of state offshore lands available for leasing in the Beaufort Sea area, including the coastal areas of the NPR4 and the Wildlife Refuge.

Department of Natural Resources Open File Report 50 gives the entire Beaufort Sea a figure of 15.5 billion barrels of recoverable oil and 41.8 trillion cubic feet of gas. The lease area is only a small part of this province, so it is difficult to estimate the amount of recoverable oil and gas. Using volumetric methods of analysis, a low estimate of petroleum resources would be 306 MMB. A low natural gas estimate would equal 129.8 TCF. There is a good possibility for these resources to lie in large deposits, and because of the proximity to Prudhoe Bay, chances of economical recovery would be good. These estimates are bottom line since there is a good chance of much larger reserves lying in the unleased vicinity of Prudhoe Bay.



North Slope (Eastern)
Be... ort ... Pr... ice

Figure G-

SECTION V

STAFF AND BUDGETING NEEDS

OF

SOME LEASING METHODS CONSIDERED

By

Jack Roderick, Deputy Commissioner

Department of Natural Resources

STAFF AND BUDGETING NEEDS

Historically, the State has operated its leasing system, both competitive and non-competitive, with a staff of fewer than 20 people. This includes management and all administrative help. Competitive bonus bid, royalty bid, cost or profit sharing (auditing) and ad valorem charge (appraising) systems of leasing, or any combination, take different levels of staffing. The type and quality of information required by the State, before and/or after leasing, controls the level.

The competitive cash bonus-fixed royalty leasing system used to date by the State causes the least administrative burden. Compared to any of the alternative systems being considered it requires the least "value judgements" by administrators and the least amount of information from companies.

Moving away from this standard system, thereby increasing the State's need for information, increases the administrative costs of the State. How much will depend upon the mix of various systems and the volume of information required by state personnel and/or consultants and contractors.

One basic assumption is made: that a system or systems of leasing can be devised that will keep the number of state personnel required to a minimum. However, the quality of the people in any system must be very high, and much of the data collection and interpretation, be it accounting or geophysical, can be contracted out.

One other assumption is that once having accepted part of the "risk" (unlike the bonus bid system) the State will not spend great amounts of money for statisticians, computer analysts and economists to only second-guess the results of lease sales. A postmortem review procedure will be necessary, but we have assumed that it will not be overly involved.

The staffing needs for the various leasing alternatives will be presented as follows:

1. Bonus bid (with delay rental);
2. Royalty bid - sliding or otherwise;
3. Cost (profit) sharing; and
4. Ad valorem (reserves) charge.

Generally, existing administrative staff in the State are capable of handling bonus bid or delay rental and royalty bid systems. Depending on the number of lease sales, the number of operators and the complexities of the ante and post sale information analysis, the "team" is presently in place. Any change in the present bonus bid system will, based on a cursory examination of other jurisdictions, cost the State more money.

At the present time, like the Federal Government, the State must do some estimating of anticipated reserves before a sale in order to evaluate the bids when received. In a royalty bid situation, more emphasis would have to be placed on monitoring production rates and establishing wellhead values after production begins. Before discovery, no significant increase in staff would appear necessary. (Australia is presently in a fight over what offshore wellhead values should be.)

A competitive royalty leasing system would inevitably require some work commitments from the (operator). The simplest commitment would be to do so much exploration work up to and including a well or wells. Some jurisdictions simply permit affidavits attesting to the work accomplished; others require certified audits. In any event, the State would have to require some auditing staff to satisfy itself that the work required to offset the smaller bonus was being done. No estimate of additional staff required under a royalty bid leasing system has been made here because the work commitments would be part of the lease terms and they are almost infinite, ie. they would be "negotiated" between the operator and the State.

The present budget of the Department of Natural Resources Division handling oil and gas leasing is approximately $1.1 million. This includes the Director of the Division of Minerals and Energy Management, a leasing manager and staff, a petroleum manager, one petroleum reservoir engineer, one petroleum economist, one petroleum geophysicist, one petroleum geologist, one petroleum engineer, and one petroleum revenue audit supervisor.

This "team" appears equipped to manage oil and gas leases in either a bonus bid or royalty bid situation. If bonuses are paid with a delay rental method several more land management officers and clerks would likely be necessary. If royalty were bid, skilled lease negotiators would be needed.

The cost (profit) sharing, or net profits, system would be the most costly to administer, again depending on the specific requirements. This, for the reason that the State would need to obtain and evaluate the operators' cost figures. A few major oil companies, it can be argued, would be easier to monitor than a large number of smaller oil operators, but one of the State's goals may be to increase the number of operators, thereby increasing the administrative costs.

Cost padding, sometimes known as "gold plating," useful life of the asset, depreciation paths, etc., in short all the necessities of auditing a business are called for in a net profits type leasing system.

Like administering on income tax (IRS), this "cost" leasing system requires that costs be allocated to tax or deduction impacts. Other governments, notably the Canadian Federal Government and several provinces are into variations on the "net profits" arrangements. Production offshore Long Beach, California involves these type of cost sharing leases.

As cost sharing leasing system would necessitate auditors experienced or trained in the petroleum exploration business. These auditors would most likely be located in a division of the government concerned with monitoring state revenue. In Alberta, approximately 100 people administer approximately 50,000 agreements (leases), where as some 60 persons are involved with "auditing" certain costs involved with petroleum production.

Knowing actual costs of operating a business will involve the State more substantially. Estimates of administrative costs to the State must be very general depending on whether State law requires financial disclosure, the general relationship between the State and the operators, and how many operators and fields are being monitored.

Based on experiences in other states and foreign countries, most administrators of leasing systems feel that a "net profits" system of leasing will cost "substantially more" to administer. Assuming the same number of operators and equal number of leases as are now being administered under the bonus bid or prospective royalty bid systems, staffing needs could double again the needs under the ad valorem charge system.

Thus, whereas an additional $240,000.00 might be expected to administer an ad valorem system, (see following), $500,000.00 could be necessary to administer a "net profits" system.

The ad valorem (reserve) charge type leasing system would place the emphasis on appraising the value of the reserves in the ground once a discovery had been made. This would necessitate determining the size of the field, the potential productivity and the estimated rate of flow. This is basically now being done by the staff of the Department of Revenue in establishing the reserves tax. Again, depending on the number of oil and gas fields involved and the level of sophistication needed (with the sums of money involved the level would need to be very high), the administrative costs could be significant.

Again, assuming several fields discovered in the Arctic and assuming an ad valorem (reserves) charge based on a percentage of assessed value of the discovered reserves, the following minimum staffing and budgeting could be anticipated to set a workable ad valorem charge:

1 petroleum assessor	$ 25,000
2 petroleum appraisors	40,000
1 petroleum economist	30,000
3 research analysts	45,000
4 contract petroleum engineers	100,000
Total salaries	$240,000

The subject of what kind of information the State should acquire prior to offering its land under any leasing system, may be as important as the system itself. How much information is necessary to make wise decisions involving public resources is a matter of continued heated debate. The debate falls between the true laissez-faire proponents on the one hand to the government owned exploration firm on the other, with the "resource manager" somewhere in between.

Also, almost as important as the amount and type of information required, is the decision of what to do with the information once acquired. Recognizing the need for confidentiality of "proprietory" information, should the subsurface information acquired by public funds be made public? What will be the result of such publication?

Each government involved with petroleum exploration has to deal with the information question. Alberta has recently begun a scheme in which it will expend some $20 million a year to acquire geophysical information. Rather than using the information to predetermine the potential of the lands to be leased or to enter into the business in competition with operators, Alberta requires that the information be made public at a nomi' ;' cost, usually after the lease sale. Alberta decided that this method would encourage competition in bonus bid sales and further activity in the later phases of exploration.

In Alaska, costs of acquiring seismic data and of modeling the results must be examined by the Legislature if it decides to direct the administration to devote more energy to "managing" the State's oil and gas resources. Attached hereto is an estimate of approximate costs of acquiring seismic data necessary to evaluate an area 100 by 15 miles in Alaska. (Appendix A). Depending on a number of variables, the costs can range from $70,000 to as high as 2 1/2 million dollars.

Caution should be used in examining these figures because they are only estimates. However, it is significant to note that joining others obviously brings the costs down and, in any event, the costs are high.

Compared to the cost of acquiring the raw data, interpreting it would be comparatively cheap. We have estimated $10,000 for a consultant to interpret 500 miles of seismic records. This latter cost becomes important particularly if reconnaissance data becomes available from the U.S.G.S or more data is acquired from operators by the State. Depending on the volume acquired more state personnel might be required. The Division